COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO ATTORNEY GENERAL'S INITIAL
REQUEST FOR INFORMATION
DATED JULY 8, 2016

12. Describe the manner in which the Company physically retires plant pursuant to the pipeline replacement program. Describe the physical process from identification of the plant that will be replaced, to accessing the pipe or other plant that will be replaced, to cutting the pipe over from the retired plant to the replacement plant, the actions that are taken to remove or secure the retired plant, and the disposition of any physical plant that is removed. Please provide a copy of all documentation that addresses this entire process from start to finish.

Response:

In general, Columbia utilizes Optimain^{DS} to characterize the pipe into a risk profile where the pipeline segments can be ranked and combined into larger AMRP projects, though risks not quantified by Optimain^{DS} may influence the priority of a project.

Once the candidate projects are identified, a budget quality estimate is developed along with a job order sketch proposing the construction work plan.

The estimate and plan are reviewed with Columbia's construction department with the estimate and plan being revised if necessary. The cumulative amount of the design capital job orders and associated blanket work is compared with the amount of replacement capital work authorized for that year and the final project list identified.

During the design process, all necessary land rights, street cut permits, railroad permits, environmental permits, etcetera are identified and obtained as required by the permitting authority. A tie-in and purge plan is developed and reviewed with the construction department. As construction nears, outreach with customers and elected officials also occurs.

Immediately prior to construction, either Columbia or Columbia's contractor, depending on who is doing the excavation, will contact Kentucky's One Call system and request locates for the utilities within the scope of the project.

Once construction begins, excavation at the tie-in holes generally occurs first. If directional boring is required, the sewer laterals are inspected with video camera equipment both before and after construction to ensure that gas pipes have not pierced sewer laterals, creating a safety hazard. If the open cut method of installation is used, construction proceeds in accordance with the work plan and permit requirements. The new main is installed and pressure tested before introducing natural gas. A connection is then made between the existing pipe that will remain in service and the new pipe while the pipe to be retired is also kept in service. The new pipe is purged of air and filled with gas. Next, the service lines are replaced and tied over from the old pipe to the new. Once all the services are tied over, the old main will be retired. This retirement involves disconnecting the old main from the active main and purging the remaining gas out of the old line. Additionally, a wipe sample of the old main is taken, when required, to ensure there are no environmental hazards being left in the ground. The old main is abandoned in place provided the results from the wipe sample come back favorably.

Columbia has a comprehensive set of gas standards that provide precise details of the Columbia's processes. That documentation is attached.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Definitions**	Standard Number: **GS 1012.010**
Supersedes: 01/01/2014		Page 1 of 11

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Parts 191.3; 192.3, 192.5, 194.5; American Gas Association (AGA); American Petroleum Institute (API); Gas Piping Technology Committee (GPTC); National Association of Corrosion Engineers (NACE); NiSource; PHMSA Pipeline Glossary

"Abandoned" means permanently removed from service. (Source: 49 CFR Part 192.3)

"Active corrosion" means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety. (Source: 49 CFR Part 192.3)

"**Administrator**" means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate. (Source: 49 CFR Part 192.3)

"Alarm" means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters. (Source: 49 CFR Part 192.3)

"Appurtenance" means an accessory, such as a fitting, that is attached to or is part of a pipeline. (Source: NiSource)

"Arc Burn" is a pipeline surface discontinuity consisting of locally re-melted or heat affected metal resulting from electrical energy between an electrode or ground and the pipeline outside of the welding groove. Lightning strikes can cause the same effect. (Source: NiSource)

"Class Location Unit" is an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline. (Source: 49 CFR Part 192.5)

"Class 1 Location" is a class location unit that has 10 or less buildings intended for human occupancy. (Source: 49 CFR Part 192.5)

"Class 2 Location" is a class location unit that has more than 10 but less than 46 buildings intended for human occupancy. (Source: 49 CFR Part 192.5)

"Class 3 Location" is:

a. any class location unit that has 46 or more buildings intended for human occupancy; or a building that is occupied by 20 or more persons during normal use; or

b. an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(Source: 49 CFR Part 192.5)

"Class 4 Location" is a class location unit where buildings with four or more stories above ground are prevalent. (Source: 49 CFR Part 192.5)

"Control Point" is a location at which gas flow originates or terminates or gas pressure is increased or decreased. Such points may include but are not limited to:

1. the outlet of a regulator (pressure decrease)
2. the outlet of a compressor station (pressure increase)
3. a gas well (gas flow originates)
4. the end of a pipeline (gas flow terminates)
5. valve (possible termination point)

(Source: NiSource)

"Control room" means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility. (Source: 49 CFR Part 192.3)

"Controller" means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility. (Source: 49 CFR Part 192.3)

"Customer buried piping" means buried piping that extends from the point of delivery to the entry of the first building downstream, or if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. The customer's buried piping does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. The point of delivery shall be considered to be the outlet of the service meter assembly, or the outlet of the service regulator or shutoff valve where no meter is provided. (Source: 49 CFR Part 192.16)

"Customer meter" means the meter that measures the transfer of gas from an operator to a consumer. (Source: 49 CFR Part 192.3)

"Customer-owned service lines" are jurisdictional pipelines owned by the customer, typically from curb valve or property line to meter. (Source: NiSource)

"Defective weld" means a weld containing an imperfection of sufficient magnitude to warrant rejection based upon the standards of acceptability as outlined in API 1104, "Welding of Pipelines and Related Facilities". (Source: API 1104)

"Dent" means a depression in the surface of the pipe, which produces a gross disturbance in the curvature of the pipe without reducing the pipe wall thickness. (Source: 49 CFR Part 192.309)

"Distribution Line" means a pipeline other than a gathering or transmission line. (Source: 49 CFR Part 192.3)

"Electrical survey" means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline. (Source: 49 CFR Part 192.3)

"Exchange Station" See "Interchange."

"Exposed underwater pipeline" means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet deep, as measured from mean low water. (Source: 49 CFR Part 192.3)

"Gas" means natural gas, flammable gas, or gas which is toxic or corrosive. (Source: 49 CFR Part 192.3)

"Gas pipeline emergency" means any sudden and unexpected situation where leakage, blowing gas, loss of gas pressure, an overpressure condition, or loss of communications or control systems have or may cause serious injury or damage to life and/or property. (Source: NiSource)

"Gate station" See "Point of delivery."

"Gathering Line" means a pipeline that transports gas from a current production facility to a transmission line or main. (Source: 49 CFR Part 192.3)

"General corrosion" is considered corrosion pitting so closely grouped as to affect the over all strength of the pipe and should be considered as affecting the pipeline's serviceability. (Source: 49 CFR Parts 192.485 and 192.487)

"Gouges" are elongated grooves or metal thinning resulting from impact and mechanical deformation of the pipe surface. Deformed metal will usually be evident at the edges. (Source: NiSource)

"Graphitization" is the process where the ferrous (iron) portion of the cast-iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal. Only gray cast-iron is susceptible to graphitization. (Source: NACE/NiSource)

"Hazard to navigation" means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet deep, as measured from the mean low water. (Source: 49 CFR Part 192.3)

"High pressure distribution system" means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer. (Source: 49 CFR Part 192.3)

NOTE: See definition of **"normal operating pressure"** for more information.

"Incident" means any of the following events:

(1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
   - (i) A death, or personal injury necessitating in-patient hospitalization;
   - (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
   - (iii) Unintentional estimated gas loss of three million cubic feet or more;

(2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

(Source: 49 CFR Part 191.3)

"Interchange" or "Interconnect" or "Exchange station" is a type of **point of delivery** (POD) where gas is exchanged between LDCs. Volumes are typically tracked and balanced on a Company-wide basis. Some interchanges are designed to flow in either direction, as needed. (Source: NiSource)

"Interconnect" See "Interchange."

"Jurisdictional facilities" means pipeline (e.g., pipe, components) located upstream of the outlet of the customer meter or the connection to the customer's houseline. (Source: NiSource)

"Line section" means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves. (Source: 49 CFR Part 192.3)

"Localized corrosion pitting" is a leaking or non-leaking area on the pipe surface that contains corrosion pits over a non-contiguous area. Localized corrosion does not necessarily affect a pipe's serviceability. (Source: NiSource)

"Listed specification" means a specification listed in section I of Appendix B of 49 CFR Part 192. (Source: 49 CFR Part 192.3)

"Low-pressure distribution system" means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer. (Source: 49 CFR Part 192.3)

NOTE: See definition of **"normal operating pressure"** for more information.

"Made Safe" means that **"adequate precautionary measures"** were completed. **"Adequate precautionary measures"** is defined as action(s) taken to reasonably ensure the public's safety, which shall be validated by ensuring that the action(s) taken resulted in the gas dissipating and the situation is non-hazardous. (Source: NiSource)

"Main" means a distribution line that serves as a common source of supply for more than one service line. (Source: 49 CFR Part 192.3)

"Market" consists of one **piping system** or several interconnecting piping systems that are supplied by an **interchange**, a **point of delivery** (POD), or multiple interconnecting interchanges and/or PODs. (Source: NiSource)

"Master meter system" means a natural gas pipeline system for distributing natural gas for resale within, but not limited to, a distinct area, such as a mobile home park, housing project, or apartment complex, where the operator of the master meter system purchases metered gas from an outside source. The natural gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means such as by rent. (Source: 49 CFR Part 191.3)

"Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of 1 year. (Source: 49 CFR Part 192.3)

"Maximum allowable operating pressure (MAOP)" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part. (Source: 49 CFR Part 192.3)

"Maximum operating pressure (MOP)" is the highest pressure at which a **piping system** may be operated. This pressure will not exceed the design pressure of the weakest link in a piping system or established MAOP of any pipeline segment and includes all components or adjoining facilities. (Source: NiSource)

"Municipality" means a city, county, or any other political subdivision of a State. (Source: 49 CFR Part 192.3)

"Navigable waterways" are those waterways 'where a substantial likelihood of commercial navigation exists. Further guidance in determining the navigable waterways is available in a geographic database of navigable waterways in and around the United States called the National Waterways Network. The database includes commercially navigable waterways and noncommercially navigable waterways. A list of the commercially navigable waterways by state can be found in the National Pipeline Mapping System at: https://www.npms.phmsa.dot.gov/CNWData.aspx. (Source: PHMSA Pipeline Glossary)

"Normal operating pressure" means system pressure as expected, either through experience or records. (Source: NiSource)

NOTE 1: For the Columbia Distribution Companies, pipeline systems are further subdivided into the following pressure system designations:

a. Low Pressure (LP), where the gas pressure in the main normally ranges from 7 to 14 inches of water column.

b. Intermediate Pressure (IP), where the gas pressure in the main normally ranges from 2 to 10 psig, but may drop to 1 psig during times of high demand.

c. Medium Pressure (MP), where the gas pressure in the main normally ranges from 11 to 60 psig, but may drop to 2 psig during times of high demand.

d. High Pressure (HP), where the gas pressure in the main or transmission line is normally greater than 60 psig.

NOTE 2: For NIPSCO, pipeline systems are further subdivided into the following pressure system designations:

a. Low Pressure (LP), where the gas pressure in the main normally ranges from 7 to 14 inches of water column.

b. Medium Pressure (MP), where the gas pressure in the main normally ranges from 2 to 100 psig.

c. High Pressure (HP), where the gas pressure in the main or transmission line is normally greater than 100 psig.

"Offshore" means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters. (Source: 49 CFR Part 191.3 & 192.3)

"Onshore" means on, or under, any land within the United States. (Source: 49 CFR Part 194.5 modified)

"Operator" means a person who engages in the transportation of gas. (Source: 49 CFR Part 192.3)

"Overpressure protection device" consists of apparatus such as a monitoring regulator or primary relief device which, under abnormal conditions, will act to reduce, restrict or shut off the supply of gas flowing into a transmission line or a distribution main in order to prevent the gas pressure from exceeding the maximum allowable operating pressure (MAOP) plus the allowable build up. (Source: GPTC/NiSource)

"Petroleum gas" means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psig at 100°F. (Source: 49 CFR Part 192.3)

"Person" means 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. (Source: 49 CFR Part 192.3)

"Pipe" means any pipe or tubing used in the transportation of gas, including pipe-type holders. (Source: 49 CFR Part 192.3)

"Pipeline" 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. (Source: 49 CFR Part 192.3)

"Pipeline environment" includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion. (Source: 49 CFR Part 192.3)

"Pipeline facility" means new and existing pipeline, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation. (Source: 49 CFR Part 192.3)

"Piping system" is a network of one or more pipeline segments between two or more designated **control point**s. (Source: NiSource)

"Pit" is an underground structure with full-opening doors for entry. (Source: NiSource)

"Point of delivery" is generally, a location (premises) where there is a change of ownership (i.e. custody transfer) of gas. There are two types of **"points-of-delivery"**:

(1) between a supplier and an LDC, which is also known as a **"gate station"** (Source: NiSource) or
(2) between an LDC and a customer, which shall be considered the outlet of the customer meter or the connection to the customers piping, whichever is further downstream, or the connection to the customer's piping if there is no meter. (Source: 49 CFR Part 192.3, definition of "service line")

"Pressure regulating station" consists of apparatus installed for the purpose of automatically reducing and regulating the gas pressure in the downstream transmission line or distribution main to which it is connected. Station apparatus may include regulators, control instruments, control lines, recording pressure devices, heater, valves, enclosures and ventilating equipment, and any piping. (Source: GPTC/NiSource)

"Purging" is the act of removing the content of a pipe or container and replacing it with another gas. (Source: NiSource)

"Replaced service line" means a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced. (Source: 49 CFR Part 192.383)

"RSTRENG®" is a software program developed by the American Gas Association to predict the remaining wall strength of corroded pipe. (Source: AGA)

"Safety-related condition" is defined as any gas-related condition that might, if not addressed, "constitute an immediate danger" or "potentially cause an incident". (Source: NiSource)

"Service line" means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter. (Source: 49 CFR Part 192.3)

"Service regulator" means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold. (Source: 49 CFR Part 192.3)

"Specified minimum yield strength (SMYS)" means:

(a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with the applicable section of the DOT code. Contact Engineering for further information.

(Source: 49 CFR Part 192.3)

"Subsurface Gas Detection Survey" is the sampling of the subsurface atmosphere through barholes and/or available openings with a combustible gas indicator (CGI). (Source: NiSource)

"Supervisory Control and Data Acquisition (SCADA) system" means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility. (Source: 49 CFR Part 192.3)

"Surface Gas Detection Survey" is a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to aboveground gas facilities using an instrument approved for this type of survey on the appropriate sensitivity scale. (Source: NiSource)

"Transmission line" means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

(Source: 49 CFR Part 192.3)

"Transportation of gas" means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce. (Source: 49 CFR Part 192.3)

"Vault" is an underground structure accessed through a limited means of access such as a manhole. (Source: NiSource)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Periodic Review of Operations and Maintenance Activities**	Standard Number: **GS 1014.010**
Supersedes: 08/01/2010		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 06/01/2012	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

The purpose of this gas standard is to provide guidelines on how periodic reviews of the work done by Company or Contract personnel is performed to determine the effectiveness and adequacy of the gas standards used in operation and maintenance activities.

2. REVIEW PROCESS

The review shall consist of observing the operation or maintenance activity being performed, including feedback from personnel performing the work and documenting if the gas standard is deficient.

These reviews may be conducted during the course of normal business processes such as:

a. External or internal audits,

b. Training,

c. Local field leadership observations, and

d. Annual O&M Manual review.

3. RECORDS

Documentation should be maintained for all procedure modifications and retraining of personnel. (i.e., WMS, LMS, or equivalent system)

If the person performing the review believes the written gas standard is ineffective or inadequate, that person shall submit a request to revise the gas standard or if applicable, to create a new gas standard. Form GS 1014.010-1 “Request for New or Revised Gas Standard” shall be used to request the revision (See Exhibit A).

Engineering Gas Standards shall be responsible for modifying gas standards when deficiencies are found in accordance with the Standards Review and Approval Process.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Periodic Review of Operations and Maintenance Activities	Standard Number: **GS 1014.010**
Supersedes: 08/01/2010		Page 2 of 2

EXHIBIT A

Request for New or Revised Gas Standard

Please fill out this form to request a new standard or suggest changes to existing operating procedures, programs, plans or manuals. Send the form to a Gas Standards team member listed at the bottom of the form. You may also send the request electronically to the "Gas Standards" mailbox via Lotus Notes. A Standards team member will review your ideas and suggestions, and then contact you for further discussion.

Name:	**Company:** Choose an item.	**Date:**
Work Location:	**Phone:**	**Supervisor:**
Standard Number & Title:	**Page/Section Number:**	**Standard Effective Date:**

What specifically do you feel should be changed?

Why do you feel it should be changed?

Please recommend specifically what the standard *should* say or mark-up a copy of the standard and include it with this sheet:

- Please submit only one suggested new standard or revision per form.
- Use additional sheets if necessary.
- Include a sketch where applicable.
- You may make additional copies of this sheet.

Send completed forms to one of the Gas Standards team members listed below:

Columbia Gas of Kentucky & COH South – **Bob Lawless** (blawless@nisource.com)
Columbia Gas of Massachusetts – **Ed Collins** (ECollins@NiSource.com)
Columbia Gas of Ohio (Columbus) – **Chris Maynard** (cmaynard@nisource.com)
Columbia Gas of Ohio (North) – **Dave Firth** (dfirth@nisource.com)
Columbia Gas of Pennsylvania & Maryland – **Phil Toomey** (ptoomey@nisource.com)
Columbia Gas of Virginia – **Chris Emerson** (cemerson@nisource.com)
NIPSCO – **Tim Wojcinski** (TJWojcinski@NiSource.com)
All Companies – Gas Standards mailbox (gas standards@nisource.com)

Form GS 1014.010-1 (01/2016)

NOTE: Form available for download on the Gas Standards MySource site.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Customer Notification**	Standard Number: **GS 1016.010**
Supersedes: 04/01/2010		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 48 CFR Part 192.16

1. GENERAL

This standard was developed for the purpose of notifying customers of their responsibility to maintain their buried gas piping. The Company shall notify each customer once in writing of the following information within 90 days of the customer first receiving gas at a particular location.

a. The Company does not maintain the **customer's buried piping**.

b. If the customer’s buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

c. Buried gas piping should be:

   1. periodically inspected for leaks,
   2. periodically inspected for corrosion if the piping is metallic, and
   3. repaired if any unsafe condition is discovered.

d. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

e. Plumbing and heating contractors can assist in locating, inspecting, and repairing the customer’s buried piping.

2. NOTIFICATION METHODS

A notification shall be sent to new customers by at least one of the following methods:

a. new customer information packet,

b. bill statements four(4) times a year, or

c. bill inserts four(4) times a year.

It is the responsibility of the Company to assure that new customers receive the required information.

Copies of the notification language are available upon request.

3. RECORDS

The Company shall maintain records that this notification has been sent to all affected customers within the previous 3 years, plus the current year.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Safety-Related Conditions	Standard Number: GS 1020.010
Supersedes: 01/01/2014	Recognition, Notification and Reporting	Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 191.1, 191.3, 191.23, 191.25, 192.605(b)(4)

1. GENERAL

A **safety-related condition** is defined as any gas-related condition that might, if not addressed, "constitute an immediate danger" or "potentially cause an **incident**".

Front line workers and front line leaders/supervisors are responsible for recognizing that a safety-related condition exists.

Contractor personnel working for the Company are also responsible for immediately notifying a Company representative of a suspected safety-related condition.

2. RECOGNIZING A SAFETY-RELATED CONDITION

Table 1 provides a list of probable safety-related conditions; however, the list is not meant to be all inclusive. Other conditions may exist that meet the definition of a safety-related condition.

The person discovering a probable safety-related condition shall promptly notify the most appropriate front line leader/supervisor. The most appropriate front line leader/supervisor might be your immediate supervisor, a technical operations leader, or a leader responsible for the local area where the condition exists.

If a probable safety-related condition exists on a **transmission line**, the front line leader/supervisor shall promptly notify the personnel responsible for managing the Company's Integrity Management Program.

NOTE: Timely notification is very important so that the condition can be investigated and corrected in a prompt manner. Also, it is possible that a formal written report may be required to be submitted to the applicable federal and state agencies within a short time frame after discovery of the condition.

Table 1

EXAMPLES OF SAFETY-RELATED CONDITIONS WHERE A FRONT LINE LEADER/SUPERVISOR SHALL BE PROMPTLY NOTIFIED		
Type of Safety-Related Condition	**Type of Facility**	**Qualifying Circumstances**
General Corrosion	**Transmission Line**	At all times.
	All others	At all times.
Localized Corrosion Pitting	**Transmission Line**	At all times.
	All others	If leakage might result in a **gas pipeline emergency** (e.g., wall to wall pavement, conduits nearby where gas could migrate, past experience in area, etc.).
Unintended Movement or Abnormal Loading by Environmental Causes	All	If the movement or loading affects the integrity of the pipeline or if the current condition might worsen.
Material / Construction Defect or Physical Damage[1]	**Transmission Line**	At all times.
	All others	If the material defect or damage affects the integrity of the pipeline.
Malfunction or Operating Error	All	If it causes pressure to increase above the MAOP or fall below the minimum operating pressure.
Leak	All	If it creates a **gas pipeline emergency.**
Any	All	If it could lead to an imminent hazard.

[1] A material defect might consist of broken bolt in a valve, faulty weld seam on pipe, coating disbondment, etc. A construction defect might consist of a faulty field weld, wrinkle bend, improper coating installation, etc. A physical damage might consist of a dent, a gouge, etc. It may also be appropriate to complete a facility damage report or a facility failure report.

3. DETERMINING IF SAFETY-RELATED CONDITION EXISTS AND IS REPORTABLE

Certain safety-related conditions are considered reportable to applicable federal and state agencies.

The front line leader/supervisor shall promptly initiate an investigation, by gathering advice from technical support personnel as necessary, and notify Engineering to determine if a safety-related condition exists and if it is reportable.

Compliance shall make the final determination if a safety-related condition exists and if it is reportable.

If the condition results in one of the following measures:

a. shutdown of operation of a pipeline for purposes other than abandonment,

b. a reduction of operating pressure (see NOTE 2 below) of a pipeline, or

c. patrolling a pipeline on a more frequent basis,

then, this may constitute a reportable safety-related condition.

Table 2 can also be used to help determine if a safety-related condition is reportable.

NOTE 1: A timely investigation must occur to meet the federal and state reporting requirements. If a safety-related condition is determined to be reportable, a written report is due to the applicable federal and state agencies within five working days (not including Saturday, Sunday, or Federal Holidays) after the day the Company first determines that the condition exists, but not later than 10 working days after the day the Company discovers the condition.

NOTE 2: The term “operating pressure” used in this gas standard typically means the actual operating pressure at the time the condition is discovered. However, if a pressure reduction has been instituted for such reasons as precautionary measures for performing indirect assessments, defects found that impact pipeline serviceability, etc., then the “operating pressure” shall be considered as the “normal operating pressure” of the pipeline for determination of reporting requirements (in Table 2 below) and not the “actual operating pressure” of the pipeline when the condition is discovered.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Safety-Related Conditions**	Standard Number: **GS 1020.010**
Supersedes: 01/01/2014	**Recognition, Notification and Reporting**	Page 4 of 7

Table 2

DETERMINATION OF REPORTING REQUIREMENTS FOR SAFETY-RELATED CONDITIONS						
Location	**Time Factor**	**Type of Safety-Related Condition**	**Effect on Facility Operation**		**Written Report Required?**[2] Operating less than 20%SMYS[3]	**Written Report Required?**[2] Operating greater than or equal to 20%SMYS[3]
Within the right-of-way of an active railroad, paved road, street, or highway Or within 220 yards of a building intended for human occupancy or outdoor place of assembly	Will not be corrected by repair or replacement within 5 working days after determination or 10 working days after discovery, whichever comes first	General Corrosion	Causes the MAOP to be reduced		No	**Yes**
			Does not cause the MAOP to be reduced		No	No
		Localized Corrosion Pitting	Leakage might result		No	**Yes**
			Leakage unlikely to result		No	No
		Unintended Movement or Abnormal Loading by Environmental Causes	Impairs serviceability		**Yes**	**Yes**
			Does not impair serviceability		No	No
		Material Defect or Physical Damage	Impairs serviceability		No	**Yes**
			Does not impair serviceability		No	No
		Malfunction or Operating Error	Causes pressure to increase above MAOP + allowable build-up		**Yes**	**Yes**
			Does not cause pressure to increase above MAOP + allowable build-up		No	No
		Leak	Creates a **gas pipeline emergency**		**Yes**	**Yes**
			Does not create a **gas pipeline emergency**		No	No
		Any Condition	Could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the Company), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline		**Yes**	**Yes**
			All others		No	No
	Will be corrected by repair or replacement within 5 working days after determination or 10 working days after discovery, whichever comes first	General Corrosion	Causes the MAOP to be reduced		No	**Yes**
			Does not cause the MAOP to be reduced		No	No
		Localized Corrosion Pitting	Leakage might result	Effectively coated & cathodically protected	No	No
				Bare & unprotected or ineffectively coated & unprotected	No	**Yes**
			Leakage unlikely to result	All conditions	No	No
		All Other Conditions	All		No	No
All Other Areas					No	No

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[2] A written report is not required for any safety-related condition that exists on a master meter system or a customer-owned service line, or is an incident or results in an incident before the deadline for filing the safety-related condition report.

[3] Consult Engineering for information regarding the operating pressure with respect to the percentage of specified minimum yield strength (SMYS).

4. WRITTEN REPORT

Once it is determined that a reportable safety-related condition exists, the *Safety-Related Condition Report*, Form GS 1020.010.1 (see Exhibit A), shall be prepared to record and communicate relevant information. Separate conditions may be described in a single report if they are closely related.

4.1 Front Line Leader/Supervisor

The front line leader/supervisor is responsible for preparing and submitting the draft *Safety-Related Condition Report* to the Compliance Manager, copying other applicable managers (Operating Center Manager, Engineering Manager, etc), within a timely manner after discovering the condition.

4.2 Compliance Manager

The Compliance Manager shall submit the final *Safety-Related Condition Report* to the Associate Administrator, Office of Pipeline Safety and simultaneously to the applicable state governmental agency within five working days (not including Saturday, Sunday, or Federal Holidays) after the day the Company first determines that the condition exists, but not later than 10 working days after the day the Company discovers the condition. Reports may be transmitted by telefacsimile (fax), dial (202) 366-7128. Copies of final versions should also be routed back to the applicable managers (Operating Center Manager, Engineering Manager, etc.) for their files.

5. FOLLOW-UP REPORTS

5.1 Front Line Leader/Supervisor

The front line leader/supervisor is responsible for updating the Compliance Manager, copying other applicable managers as necessary, on a periodic basis until the safety-related condition is resolved. Follow-up reports should utilize the *Safety-Related Condition Report* form.

5.2 Compliance Manager

The Compliance Manager is responsible for updating the federal and applicable state regulatory agencies when deemed necessary, or as requested. Follow-up reports should utilize the *Safety-Related Condition Report* form. Copies of final versions should also be routed back to the applicable managers (Operating Center Manager, Engineering Manager, etc.) for their files.

6. RECORDS

A file of all safety-related condition reports shall be maintained by the Company's Compliance Manager. In addition, copies of all safety-related condition reports for transmission lines shall be filed with the Integrity Management Program (IMP) files for the applicable transmission line and retained for the life of the pipeline. Also, Engineering should file a copy of each safety-related condition report within the appropriate **Maximum Allowable Operating Pressure** (MAOP) record file and retain for the life of the pipeline.

EXHIBIT A

SAFETY-RELATED CONDITION REPORT

TO: ASSOCIATE ADMINISTRATOR
DEPARTMENT OF TRANSPORTATION
OFFICE OF PIPELINE SAFETY
FAX: (202) 366-7128

INITIAL REPORT ☐
SUPPLEMENTAL REPORT ☐

COMPANY NAME/OPERATOR ID: <PICK FROM LIST>
STREET ADDRESS:
CITY: STATE: ZIP:

NATURAL GAS ☐ LNG ☐ | ONSHORE ☒ OFFSHORE ☐

LOCATION OF SAFETY-RELATED CONDITION (nearest street address, intersection, survey station number, milepost, landmark, or name of pipeline):

CITY/TOWNSHIP: COUNTY: STATE:

DATE CONDITION DISCOVERED: DATE CONDITION DETERMINED TO BE REPORTABLE:

PERSON WHO DETERMINED THAT THE REPORTABLE CONDITION EXISTS:

TITLE: PHONE NUMBER:

DESCRIPTION OF CONDITION (including circumstances leading to discovery and any significant effects of the condition on safety):

INITIAL CORRECTIVE ACTION TAKEN (before report is submitted):

ADDITIONAL ACTION TO BE TAKEN:

ANTICIPATED START DATE: ANTICIPATED COMPLETION DATE:

SUBMITTED BY: DATE:
TITLE: PHONE NUMBER:

Form GS 1020.010-1
(01/16)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Incident Reporting**	Standard Number: **GS 1020.020**
Supersedes: 01/01/2013		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 191.1, 191.3, 191.5, 191.7, 191.9, 191.15, 191.23, 191.25; 192.605(b)(4)

1. REPORTABLE INCIDENTS

The Company shall follow federal and applicable state regulations when reporting an **incident**. Procedures for adhering to these regulations are found in the Company's emergency plan.

An incident, for the purpose of this procedure, means any of the following events.

a. An event that involves a release of gas from a pipeline or from an LNG facility and results in:
   1. a death, or personal injury necessitating in-patient hospitalization;
   2. estimated property damage of $50,000 or more, including loss to the Company and others, or both, but excluding the cost of gas lost; or
   3. unintentional estimated gas loss of three million cubic feet (3000 mcf) or more.

b. An event that results in an emergency shutdown of an LNG facility.

c. An event that is significant, in the judgment of the Company, even though it did not meet the criteria of paragraphs (a) or (b).

2. NOTIFICATION REQUIREMENTS

2.1 Immediate Notification

2.1.1 Federal

The Company shall give notice at the earliest practicable moment following confirmed discovery of each incident, but not later than one (1) hour following the time of such confirmed discovery.

For the purposes of this procedure, "confirmed discovery" is when the incident has been verified by Company leadership (e.g., FOL, FLL, Supervisor, Compliance Manager, incident management team), based upon an assessment of the data reported by the first responder.

Each notice shall be made by either telephone to the National Response Center (NRC) (800-424-8802) or electronically at http://www.nrc.uscg.mil and shall include the following information:

a. Company name and person making report and their telephone numbers,

b. the location of the incident,

c. the time of the incident,

d. the number of fatalities and personal injuries, if any, and

e. all other significant facts that are known by the Company that are relevant to the cause of the incident or extent of the damages.

If additional information is gained within 48 hours following an incident that leads to a change (greater or lesser) in the estimated number of fatalities and injuries or the estimated property damage is 10 times greater than the initial reported property damage estimate, the Company should make an additional report to the NRC referencing the initial NRC Report Number.

2.1.2 State Telephonic Reports

For State telephonic reporting requirements refer to the following documents.

a. Columbia – Emergency Manual Section 4.

b. NIPSCO – Emergency Operating Plan.

2.2 Written Reports

2.2.1 Federal

The Company shall submit the applicable Pipeline and Hazardous Material Safety Administration (PHMSA) Form PHMSA F7100.1 “Incident Report – Gas Distribution System” for a distribution pipeline system and Form PHMSA F7100.2 “Incident Report – Gas Transmission And Gathering Systems” for a transmission or a gathering pipeline system as soon as practicable but not more than 30 days after detection of an incident.

Refer to the applicable LNG Plan for reporting incidents related to LNG facilities.

Where additional related information is obtained after a report is submitted, the Company shall make a supplemental report, when deemed necessary, as soon as practicable with a clear reference by date and subject to the original report.

Written reports shall be filed electronically via the PHMSA electronic on-line reporting system, available at the following URL: https://opsweb.phmsa.dot.gov/cfdocs/opsapps/pipes/main.cfm.

2.2.2 State

For state written reporting requirements refer to the following documents:

a. Columbia – Emergency Manual Section 4.

b. NIPSCO – Emergency Operating Plan.

2.3 Rescinding Reports

If an incident is found not to meet the criteria of a reportable incident (as identified in Section 1 above) after the initial notification, an e-mail request to rescind the initial notification shall be submitted to the federal authorities at the following e-mail address:

InformationResourcesManager@phmsa.dot.gov

Requests shall include the following information, if applicable:

a. Report ID (the unique 8-digit identifier assigned by PHMSA),

b. Company name,

c. PHMSA-issued OPID number for applicable Company,

d. the number assigned by the National Response Center (NRC) for the immediate notification (if supplemental reports were made to the NRC for the event, list all NRC report numbers associated with the event),

e. date of the event,

f. location of the event, and

g. a brief statement as to why the report should be retracted.

This e-mail should also be sent or forwarded to the applicable state authority Refer to the applicable emergency manual/plan for the appropriate state commission contact information.

3. RECORDS

The Company should retain a copy of the applicable regulatory forms and reports that were submitted.

NiSource
Distribution Operations

Gas Standard

Effective Date: 06/01/2014	**Reporting Exceedances of Maximum Allowable Operating Pressure for Transmission Lines**	Standard Number: **GS 1020.030**
Supersedes: N/A		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE Section 23 Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011; PHMSA Advisory Bulletin ADB-2012-11

1. GENERAL

This reporting requirement applies only to Company-owned gas transmission lines.

The Company must report to PHMSA and the State each occurrence of when a pipeline pressure exceeds maximum allowable operating pressure (MAOP) plus the build-up allowed for operation of pressure-limiting or control devices.

2. REPORTING EXCEEDANCES OF MAOP

The person discovering a condition that the pressure in a transmission exceeds the MAOP, plus the build-up allowed for operation of pressure-limiting or control devices, shall promptly notify their front line leader/supervisor.

When notified, the front line leader/supervisor shall promptly notify their Manager. The Manager, or designee, shall immediately notify the Compliance Manager.

NOTE: Timely notification is very important so that the condition can be investigated and corrected in a prompt manner. In addition, a written report is required to be submitted to the applicable federal and state agencies within five calendar days of occurrence.

3. WRITTEN REPORT

Once it is determined that an exceedance of MAOP plus allowable build-up occurred, Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report” (see Exhibit A) shall be prepared to document and communicate relevant information.

Using Form GS 1020.030-1, the written report shall provide the following information.

a. The name and principal address of the operator, date of the report, name, job title, and business telephone number of the person submitting the report.

b. The name, job title, and business telephone number of the person who determined the condition exists.

c. The date the condition was discovered and the date the condition was first determined to exist.

d. The location of the condition, with reference to the town/city/county and state or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, and the name of the commodity transported or stored.

e. The corrective action taken before the report was submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

4. REPORTING TIMEFRAME

Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report” shall be submitted on or before the fifth calendar day following the date on which the exceedance occurs. Calendar days include Saturday, Sunday and holidays.

There are no reporting exemptions like there is for safety-related condition reporting (see GS 1020.010 Safety-Related Conditions).

5. RESPONSIBILITIES

5.1 Front Line Leader/Supervisor

The front line leader/supervisor is responsible for preparing and submitting the draft Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report” to the Compliance Manager, copying other applicable managers (e.g., Operating Center, Gas Control, Engineering, Transmission Integrity Management, etc.), within a timely manner after discovering the exceedance.

5.2 Compliance Manager

The Compliance Manager shall submit the final Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report” to the Associate Administrator, Office of Pipeline Safety and simultaneously to the applicable state governmental agency within five calendar days of occurrence. Reports may be transmitted by telefacsimile (fax) at (202) 366-7128.

Copies of final version should also be routed back to the applicable managers for their files.

6. FOLLOW-UP REPORTS

6.1 Front Line Leader/Supervisor

The front line leader/supervisor is responsible for updating the Compliance Manager, copying other applicable managers as necessary, on a periodic basis until the exceedance and documented additional actions are resolved. Follow-up reports should utilize Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report.”

6.2 Compliance Manager

The Compliance Manager is responsible for updating the federal and applicable state regulatory agencies when deemed necessary, or as requested. Follow-up reports should utilize Form GS 1020.030-1 “Gas Transmission MAOP Exceedance Report.” Copies of final versions should also be routed back to the applicable managers for their files.

7. RECORDS

The Company’s official file of all exceedance reports shall be maintained by the Company’s Compliance Manager for the life of the pipeline facility.

Copies of all exceedance reports shall be filed with the Integrity Management Program (IMP) files for the applicable transmission line and retained for the life of the pipeline.

EXHIBIT A

GAS TRANSMISSION MAOP EXCEEDANCE REPORT

TO:	**ASSOCIATE ADMINISTRATOR** **DEPARTMENT OF TRANSPORTATION** **OFFICE OF PIPELINE SAFETY**	**E-mail** **Fax**	InformationResourcesManager@dot.gov or (202) 366-7128

COMPANY NAME/OPERATOR ID:
STREET ADDRESS:
CITY: STATE: ZIP:

LOCATION OF CONDITION (with reference to the town/city/county and state, and as appropriate: nearest street address, intersection, survey station number, milepost, landmark, and the name of the commodity transported):

CITY/TOWNSHIP: COUNTY: STATE:

DATE CONDITION DISCOVERED: DATE CONDITION WAS FIRST DETERMINED TO EXIST:

PERSON WHO DETERMINED THAT THE REPORTABLE CONDITION EXISTS:

TITLE: PHONE NUMBER:

DESCRIPTION OF CONDITION (including circumstances leading to discovery and any significant effects of the condition on safety):

INITIAL CORRECTIVE ACTION TAKEN (before report is submitted):

ADDITIONAL ACTION TO BE TAKEN:

ANTICIPATED START DATE: ANTICIPATED COMPLETION DATE:

SUBMITTED BY: DATE:
TITLE: PHONE NUMBER:

Form GS 1020.030-1
(06/2014)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	PHMSA Notifications for Large Projects and Other Events	Standard Number: GS 1022.040
Supersedes: 01/01/2012		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 191.22

1. GENERAL

The Company shall notify the Pipeline and Hazardous Materials Safety Administration (PHMSA) of certain events identified within this gas standard.

2. TYPES OF PROJECTS OR EVENTS

2.1 Large Projects

Notifications of the following types of large projects shall be made to PHMSA no later than 60 days before construction begins:

a. construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more;

b. construction of 10 or more miles of a new or replacement pipeline; or

c. construction of a new LNG plant or LNG facility.

NOTE: If a 60 day notice is not feasible because of an emergency, notification to PHMSA must be made as soon as practicable.

2.2 Other Events

Notifications of the following types of events shall be made to PHMSA no later than 60 days after the event occurs:

a. a change in the primary entity responsible for managing or administering a safety program covering pipeline facilities operated under multiple Operator Identification Numbers (OPIDs);

b. a change in the name of the Company;

c. a change in the Company responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility;

d. the acquisition or divestiture of 50 or more miles of a pipeline or pipeline system; or

e. the acquisition or divestiture of an existing LNG plant or LNG facility.

3. REPORTING REQUIREMENTS

The notifications to PHMSA shall be made electronically through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov. A blank copy of Form PHMSA F 1000.2 “Operator Registry Notification” and instructions can be found at http://phmsa.dot.gov/pipeline/library/forms.

The Company shall use the appropriate company-specific Operator Identification Number (OPID) issued by PHMSA for identification purposes for all notifications required by this gas standard.

4. RESPONSIBILITY

The responsibility for compiling the information required for the notification of large projects or other events is shared between several job functions. Table 1 below shows the responsible job functions within the Company.

Table 1 – Responsibility for Compiling Information Required for Notification to PHMSA for Large Projects and Other Events

Type of Event	Responsible Job Function
Large Project (as defined in Section 2.1 above)	Field Engineer or Project Manager (whichever Engineering group is managing the project)
A change in the primary entity responsible for managing or administering the Drug and Alcohol Program	Human Resources – Lead Substance Abuse Administrator
A change in the primary entity responsible for managing or administering the Operator Qualification Program	Compliance & Technology – Operator Qualification Program Specialist
A change in the name of the Company or A change in the Company responsible for an existing pipeline, pipeline segment, or pipeline facility (e.g., company merger)	NiSource Corporate Secretary
The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system	Field Engineering Leadership
The acquisition or divestiture of an existing LNG plant or LNG facility or A change in the Company responsible for an existing LNG facility	System Operations Leadership

The information regarding these types of projects or events (i.e., compiled on Form PHMSA F 1000.2) shall be forwarded to the appropriate Compliance Manager as soon as practicable to allow for the electronic notification to PHMSA no later than the following.

a. For large projects (as defined in Section 2.1 above), 60 days before the project begins.

b. For other events (as defined in Section 2.2 above), 60 days after the event occurs.

The Compliance Manager shall submit the notifications to PHMSA required by this gas standard.

The notifications to PHMSA shall be made electronically through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov.

5. RECORDS

A file of the notifications to PHMSA required by this gas standard should be maintained by the Compliance Manager.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	**PHMSA Annual Reporting Requirements**	Standard Number: **GS 1030.010**
Supersedes: 01/01/2014		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 07/01/2014	☑ CGV ☑ CKY ☑ CMA	☑ CMD ☑ COH ☑ CPA

REFERENCE 49 CFR Part 191.7, 191.11, 191.12, 191.13, 191.17, 192.383(c), 192.1009(a), Pipeline Safety Improvement Act of 2002 (Section 15)

1. GENERAL

The Company shall submit the following reports to the Pipeline and Hazardous Materials Safety Administration (PHMSA) each year, not later than March 15, for the preceding calendar year. Reports shall be filed electronically to PHMSA via the Office of Pipeline Safety (OPS) On-Line Data Entry System, or as otherwise specified.

When compiling each report, refer to the instructions corresponding to the specific PHMSA form, which can be found on-line in the PHMSA forms library.

2. DISTRIBUTION SYSTEM ANNUAL REPORT

The Company shall submit a separate annual report for each state in which it operates a distribution pipeline system on DOT Form PHMSA F 7100.1-1 “Gas Distribution System (Annual Report).”

Pipeline Safety and Compliance is responsible for gathering the reporting data and submitting the individual state reports to PHMSA.

3. TRANSMISSION SYSTEM ANNUAL REPORT

The Company shall submit a separate annual report for each state in which it operates a transmission pipeline system on DOT Form PHMSA F 7100.2-1 “Gas Transmission and Gathering Systems (Annual Report).”

Pipeline Safety and Compliance is responsible for gathering the reporting data and submitting the individual state reports to PHMSA.

4. MECHANICAL FITTING FAILURE REPORTS

Each mechanical fitting failure resulting in a Grade 1 leak, as required by GS 1652.015 “Reporting of Mechanical Fitting Failures,” must be submitted on DOT Form PHMSA F-7100.1-2 “Mechanical Fitting Failure Report” (MFFR). MFFRs may be submitted to PHMSA throughout the year, as long as all required MFFRs for the preceding calendar year are submitted by March 15 of the following year.

The responsibility for gathering the reporting data and submitting the report(s) to PHMSA is Pipeline Safety and Compliance. The reporting data is gathered from the Facility Failure Reporting System.

5. UPDATES TO THE NATIONAL PIPELINE MAPPING SYSTEM (NPMS)

The Company shall submit updates to the PHMSA National Pipeline Mapping System (NPMS) for the Company's transmission pipeline system and liquefied natural gas (LNG) plants on an annual basis. Updates must reflect any and all changes in geospatial data, attribute data, metadata, or public contact information.

Refer to the following documents for additional submittal guidance.

a. NPMS Standards for Pipeline, LNG and Breakout Tank Farm Operator Submissions.

b. NPMS Operator Submission Guide: Tips for Preparing a Complete and Accurate NPMS Submission.

The responsibility for gathering the reporting data and submitting updates to the NPMS is the GIS Support group.

6. SUBMISSION OF ANNUAL REPORTS TO STATE COMMISSIONS

Copies of the annual reports submitted to PHMSA, with the exception of the updates to the NPMS, shall be forwarded to the applicable state commission by March 15 by the group responsible for submitting the reports to PHMSA.

7. RECORDS

A file of the annual reports submissions to PHMSA required by this gas standard should be maintained by the group responsible for submitting the reports to PHMSA.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Locating Gas Facilities	Standard Number: **GS 1100.010(KY)**
Supersedes: 07/01/2011		Page 1 of 7

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.614

1. GENERAL

This standard provides guidance for performing field locating and marking of gas facilities. However, it cannot address every field condition that may be encountered in the course of performing a field locate request. Therefore, locate personnel should contact local leadership for additional guidance, as needed.

Locate personnel shall have current/valid qualification(s) for the work being performed as set forth in the Company's or contractor's OQ Plan(s).

Locate personnel shall use appropriate safety equipment and avoid unnecessary risks. Request assistance if needed to perform the work safely.

2. PROCEDURE

2.1 Prior to Locating Facilities

2.1.1 Review the One-Call Ticket

Read One-call ticket thoroughly to verify location, type, and scope of work, etc. Verify the correct location in which to conduct the locate. Ensure that the scope of work area is clearly defined.

If the instructions on the One-call ticket are unclear, call the contact person/excavator for clarification. Refer to the guidance in Section 2.1.4 for more information.

2.1.2 Perform a Site Assessment

Identify any white pre-markings. Any required pre-marking that is not present shall be documented within the ticket management system.

Never assume that existing locate markings are correct. Do not refresh marks without confirming accuracy by physical locating means.

Identify conditions that could negatively impact locate accuracy, such as a high voltage line in vicinity, other utilities, terrain, vehicles parked over the pipeline, structures, high traffic area, etc. If conditions cannot be resolved, inform leadership and document within the ticket management system.

If premature excavation is observed, report this information to the local Damage Prevention Coordinator and/or local leadership immediately.

2.1.3 Review Company Records

Review all necessary maps, records, work orders, service line data, etc. Perform a visual inspection to identify incorrectly documented or missing facilities. Identify new utility construction or repair patches. Contact the appropriate office for assistance if additional records are necessary.

2.1.4 Guidance for Contacting the Contact Person/Excavator

If any part of the One-call ticket is unclear or the site assessment generates questions, the contact person/excavator shall be contacted to verify the nature and limits of proposed excavation, as well as to verify the excavator's understanding and recognition of marks to be placed on the site.

Meetings/conversations with the contact person/excavator shall be documented within the ticket management system and shall include identification of the individuals involved and any agreements made in regards to construction at the site.

If the contact person/excavator cannot be reached, document within the ticket management system.

2.2 Locating Facilities

Select the proper instrument and locating technique for the type of facility to be located.

Locate personnel shall operate equipment in accordance with the manufacturer's instructions.

Physical direct conductive (direct contact) locating is to be used where practical. In areas where meters are inside and no direct contact access is available outside, attempt to gain access to make direct contact. If necessary, leave a card explaining the need to locate the facilities and contact the excavator to advise of the delay.

Inductive locating should only be used when conductive locating is not practical. Be aware of other utility structures close by, either overhead or below ground. Always sweep the area to identify multiple signal paths. Look for evidence of other facilities or

Effective Date: 01/01/2016	Locating Gas Facilities	Standard Number: **GS 1100.010(KY)**
Supersedes: 07/01/2011		Page 3 of 7

structures (both buried and above ground) and be aware of potential bleeding of signal.

Identify if the area being located has electronic markers installed. If so, use the proper locate equipment to find and identify electronic markers at service tees and along Company facilities as necessary.

Always locate Company and customer service lines up to the meter. If not able to locate a customer-owned service line, the contact person/excavator should be notified or an appropriate notice must be left at the site.

Inspect permanent line markers within the scope of the ticket to validate accurate Company information and assure good condition of the line marker. Company line markers with incorrect information shall be corrected. Line markers that are suspected to be missing, damaged or in poor condition should be reported to local leadership for replacement or repair.

2.3 Unlocatable Facilities

Follow the local process when facilities cannot be located.

2.4 Marking Facilities

The sections below offer guidance for marking facilities. Follow the applicable state marking standards.

2.4.1 Operating Conditions

Facilities must be adequately marked for the conditions and expected activity. Conditions such as snow, rain, vegetation, high traffic, and construction should be considered when selecting the marking method.

2.4.2 Uniform Color Code

Underground utilities may be marked with paint, flags, stakes, or any combination of these utilizing the American Public Works Association (APWA) color codes. Yellow is the standard color for marking underground gas facilities. Chart 1 shows each color and corresponding use as set by APWA.

Chart 1. APWA Color Codes

	YELLOW – Gas, Oil, Steam, Petroleum or Gaseous Materials		**PURPLE** – Reclaimed Water, Irrigation and Slurry Lines
	RED – Electric Power Lines, Cables, Conduit and Lighting Cables		**GREEN** – Sewer and Drain Lines
	BLUE – Potable Water		**PINK** – Temporary Survey Markings
	ORANGE – Communications, Alarm or Signal Lines, Cables or Conduits		**WHITE** – Proposed Excavation

2.4.3 Marking Materials

Markings may include one or any combination of the following – paint, flags, chalk, stakes, brushes / whiskers. Offset marks should be used where marks are likely to be destroyed or in areas where it is not possible to mark the centerline of a facility, and such offset marks shall be documented within the ticket management system.

2.4.4 Marking

Mark all facilities and paint valve box covers within the scope of the locate request. Extend marks at least 25 feet beyond established work zone (50 feet preferred). At a minimum, service branches should be marked at the main, on curbs, and at some offset point outside the work (on private property if necessary) to preserve the marks.

Every effort should be made to mark the centerline of the facility. Painted marks should be approximately 2 inches wide and 18 inches long and visible from adjacent marks.

Facility flags should supplement paint marks, where practicable. On pavement, a “G” (for gas) should be painted approximately every 2 marks. Facility stake chasers (brushes or whiskers) may be used for road construction or high traffic jobs in dirt in conjunction with paint. In areas where other gas utilities have facilities in proximity to ours, use “CG” (Columbia Gas) or appropriate designation to identify the markings. (Local operations management will determine where overlapping service territories exist and where the Company designation is necessary.)

Identify size (width) of facilities two inches and over.

Perpendicular lines should be used to indicate dead ends.

Arrows should be used at the ends of the marking site to indicate that the facility continues.

Identify the type of material that an excavator could expose for all mains and for services over 2 inches with the following abbreviations.

a. CI = Cast Iron Pipe.

b. PL = Plastic Pipe, or for plastic inserted into non-rigid (plastic, PVC) conduits.

c. ST = Steel Pipe.

d. ST/INS = Steel with plastic insert (use only for plastic inserted into rigid/metallic conduits).

2.5 Prior to Leaving the Site

Before leaving the site, locate personnel shall review the locate request and verify that any markings are adequate and match the records. Locate personnel shall relay any concerns to local leadership. Locate personnel shall notify the contact person/excavator according to Section 2.1.4 above if difficulties will delay the marking beyond the ticket due date and document such notifications on the request.

In addition, the following tasks shall be completed after the locate request has been performed prior to leaving the site.

2.5.1 Record Revisions

Determine if Company record (e.g., map or GIS, service line record) revisions are needed based on the locate work performed. See Section 3.2 below for guidance regarding record revisions.

2.5.2 Identification of Suspected Encroachments

Based on the locate work performed, identify suspected encroachments, such as buildings intended for human occupancy or other structures (e.g., shed, fence, pool) that may have been installed over a Company facility or a customer owned service line. Report suspected encroachments to the Integration Center to create a job order for further investigation.

Refer to GS 2650.010 “Guidelines for Avoidance of Encroachment on Company’s Rights-of-Way” for additional guidance if the suspected encroachment impacts the Company’s right-of-way.

2.5.3 Identification of Suspected Cross Bores

Be aware of potential Cross Bore related conflicts.

For the purposes of this gas standard, a Cross Bore is defined as "a natural gas pipeline that has inadvertently transected another underground utility (including, but not limited to, a sewer line, septic system, electrical conduit, or other similar facility) resulting in a potentially unsafe situation."

Report suspected Cross Bore related conflicts to local leadership for further investigation.

3. RECORDS

3.1 Data

Document in accordance with the specific ticket management system in use. Locate personnel shall verify and document the marking of underground facilities. Documentation may include, but is not limited to, the following.

a. Ticket number.

b. Address or location where markings were placed.

c. Scope of the locate (e.g., north side of property).

d. Notes regarding existing (or non-existing where required) white pre-markings.

e. Meetings/conversations with excavator (e.g., date, time, discussion notes).

f. Date and time locate was completed.

g. A sketch of markings with measurements to permanent reference points.

h. Facility type marked.

i. Marking medium used (flags, paint, stakes, etc.).

j. Facility size and material.

k. Photographs if applicable.

l. Locator's name and signature.

3.2 Discovery of Inaccurate Records

Upon the discovery of an inaccurate map/GIS record, locate personnel shall submit a map revision according to GS 2610.040 "Map Revisions" to the email address: MapRevisions@nisource.com.

For service line record revisions, locate personnel shall fill out a new Form GS

3020.012-1 “Service Line Record” as indicated in GS 3020.012 “Installation of Service Lines - Records.” Whenever errors are found and corrected information is submitted on Form GS 3020.012-1, the information shall be corrected and/or filed in accordance with GS 3020.012 “Installation of Service Lines - Records.”

IN THE EVENT THAT A COMPANY CONTRACTOR DISCOVERS A NEED TO UPDATE COMPANY RECORDS, A REQUEST SHALL BE SUBMITTED TO FACILITIES RECORDS & ENHANCEMENT – PIPELINE SAFETY & COMPLIANCE (EMAIL: MAPREVISIONS@NISOURCE.COM) OR TO THE OPERATIONS CENTER FOR THE COMPANY TO VERIFY AND SUBMIT ANY UPDATES.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Damage Prevention – Blasting Activities	Standard Number: GS 1100.020
Supersedes: 01/01/2014		Page 1 of 8

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR PART 192.614

1. GENERAL

This standard provides guidance for planning and precautions when blasting operations are to be done within 300 feet to any gas facilities.

Field Engineering shall be contacted whenever the Company receives notification or becomes aware of a contractor's intent to blast near its facilities. The engineer overseeing a blasting project will contact additional area personnel as appropriate to develop a plan and assignment of responsibilities.

2. BLASTING GUIDELINES

Prior to any blasting near Company facilities a leakage survey shall be performed within the effective blast area to determine the gas facilities' initial condition and shall extend a minimum distance of 300 feet in each direction. A leakage survey shall also be conducted after each blasting operation within the effective blast area to assure the integrity of the facilities. After blasting has been completed for the entire project, a final leakage survey shall be performed as soon as practicable after completion of the final blasting to assure the integrity of all gas facilities within the effective blast area.

It is recommended that a representative from the blasting contractor be given the opportunity to accompany the leakage surveyor during every leak survey performed. Any damage or leakage found shall be reported to the blasting contractor along with recommendations of whether continued blasting is advisable or whether immediate repair actions must be taken prior to commencement of blasting activities.

The Company shall request blasting data from the blasting contractor in advance of the proposed blasting activity. The blaster or contractor should fill out the upper portion of Exhibit A form GS 1100.020-1"Blasting Data Sheet" for use in the evaluation. In the event the information is not received, the Company may notify the blasting permit issuer and/or other governing authorities.

The recommended allowable stress for each steel pipeline should be based on the class location of the pipeline.

a. Class 1 location – 72% of SMYS

b. Class 2 location – 60% of SMYS

c. Class 3 and 4 location – 50% OF SMYS

2.1 Plastic Pipe Guidelines

Blasting near plastic pipe is permitted. The following guidelines will assist in determining if the blasting may be conducted. If the bottom of the blast hole is below the bottom of the pipe then the hole should not be deeper than the depth of the pipe plus one-half the horizontal distance between the blast hole and the pipe. See Exhibit C for more information.

Example 1: Pipe is 3 feet deep. Proposed blasting hole is 10 feet away and 15 feet deep. Allowable blast hole depth calculation: 3 (pipe depth) + 5(1/2 horizontal distance between pipe and blast hole) = 8 feet. Blasting should not be allowed without further review by a qualified blasting engineer (third party if needed).

Example 2: Pipe is 3 feet deep and blast hole is 10 feet deep and 20 feet away. Allowable blast hole depth calculation: 3 + 10 = 13. Blasting may be permitted pending engineering review of plans including size of charge, soil type, size of blast hole, spacing of holes and timing sequence of the blasting.

3. PRIOR TO BLASTING

After notification of blasting operations is received, an engineer shall contact the blasting operator to set up a line of communication and pre-blasting meetings as necessary. Information discussed during the meetings may include, but is not limited to, the following.

a. A comprehensive review of the plans and specifications.

b. Verification of facility location, pipe diameter, wall thickness, material kind, and condition as known.

c. Blasting and construction schedules and deadlines.

d. Blasting contractor contact person(s).

e. Definition of responsibilities (Company and blaster).

f. Safety specifications to be followed at the blast site.

g. Plans for additional meetings if necessary.

h. Means by which the company will verify the location of its facilities.

i. Blasting areas and locations.

j. Depth of charge and distance to gas facilities.

k. Size and type of charges.

l. Company requirements for pre and post blasting.

m. Blasting contractor responsibilities in the event of damages, including safety and financial obligations.

n. Facility operating pressures.

o. Whether the facility can remain in service during blasting operations.

Engineering will also identify critical valves to isolate the blast area in the event of an emergency.

A letter stipulating the responsibility inherent with blasting and excavating near Company facilities may be furnished to the blasting contractor (Exhibit B) by certified mail.

4. DURING BLASTING

Personnel representing the company at the blasting site should have an understanding of the facilities in the area and have the ability to activate emergency plans. If there is more than one Company person involved with the blasting project they shall have a means of communicating to one another.

A Company representative should be designated as the primary contact for the blasting contractor's person in charge at the blast area to assist with the following:

a. To ensure the safety of Company personnel.

b. To inform the blasting contractor of any problems that develop on Company facilities.

c. To coordinate movement of company personnel into and out of the blast area to perform leakage surveys.

d. To verify when blasting operations are completed.

It is the responsibility of the blasting contractor's person in charge to inform Company personnel when it is or is not safe to enter the blasting area. All Company personnel must adhere to the safety specifications set by the blasting contractor at all times.

5. AFTER BLASTING

After blasting operations have been completed and the blasting contractor has assured safe entry into the blast area, Company personnel shall perform the following tasks:

a. Conduct a leakage survey of the entire blast area,

b. inspect all facilities and appurtenances to ensure no damage has occurred,

c. document the results of each survey performed, and

d. conduct a follow-up leakage survey after the blast area has been restored to normal conditions.

6. RECORDS

The local Operations Center shall maintain the following records according to Company retention policy relating to blasting operations performed within 300 feet to gas facilities:

a. Items discussed during meetings with the blasting contractor if documented, that directly impact operations and safety of the Company's facilities and employees,

b. copies of the blasting plan, and

c. all inspection and leakage survey documentation.

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Distribution Operations

Gas Standard

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EXHIBIT A

Blasting Data Sheet			
To Be Filled Out By Blasting Company			
Blasting Company		**Contracting Company**	
Contact Name		**Contact name**	
Address		**Address**	
Phone Numbers		**Phone Numbers**	
Blasting Permit #			
Date Submitted to NiSource			
Project Name			
Purpose of Blasting			
Type Of Explosive (ANFO equivalent)			
Total weight (LBS) of explosive and any additives per delay			
Minimum Delay Period (milliseconds)			
Distance (ft) of nearest hole to pipeline facility			
Depth of Hole(s) (ft) – relative to pipeline			
Total weight (lbs) of explosive and any additives in hole			
Spacing between holes (ft)			
Number of holes denoted during shot			
Blast Pattern type (single shot, line grid)			
Distance (ft) to nearest Residence			
For Company Use Only			
Pipeline Facility Name		**Facility Description**	
Diameter		**Wall Thickness**	
Grade		**MAOP**	
Coupled or Welded		**Field Location**	
State		**Inventory Map#**	
Percent SMYS			
Blasting Plan Evaluation			
Blasting Plan Evaluated By		**Date**	
Onsite Evaluation		**Leak Surveys**	
Blast Date		**Leak Survey Date**	**Leak Survey results**
One-call Ticket Number			
Number of site inspectors			

Form GS 1100.020-1
(3-2013)

EXHIBIT B
(1 of 2)

Sample Letter

(YOUR NAME)

(title)

(street address)

(city, state, zip)

(DATE)

Mr. (contact name)
(name of blasting company)
(street address)
(city, state, zip)

Re: Blasting operations near (Company name) Facilities
(township, county, state where blasting is to occur)

Dear Mr. (contact name):

(Company name) acknowledges your notification of blasting operations to be conducted near, or adjacent to, our natural gas distribution facilities along (name of street/road).

Please note the following facts pertaining to blasting operations that might be contemplated near (Company name) gas facilities:

EXHIBIT B
(2 of 2)

- Anyone conducting blasting operations in the vicinity of gas pipeline shall be held fully responsible for the protection of both the lateral and subjacent support for all such pipelines and appurtenances. No blasting operations shall be conducted until the actual proximity of the pipeline to the proposed operation has been established and suitable arrangements have been made for the protection of, and access to, (Company name) facilities.
- Blasting operations near gas pipelines shall be conducted in a safe manner in accordance with all applicable safety codes and any damages, injuries or losses resulting from your blasting operations will be your responsibility.
- (Company name) and its agents shall have access to its pipelines, valves and other appurtenances at all times.

Instantaneous shots of combined charges are not permitted. All shots of a delay character shall have a minimum of an eight-millisecond delay.

In order for (Company name) to meet its requirement to conduct inspections, notification shall be given at least one week prior to the start of blasting operations.

(Company name) welcomes the opportunity to work with you and thanks you in advance for your cooperation. If you have any immediate questions concerning this correspondence, please contact me at (xxx-xxx-xxxx).

In the future, regarding these matters, please contact:

(FOL/FLL/Supervisor)

(title)

(Company name)

(address)

(city, state, zip)

Phone: (xxx-xxx-xxxx)

Sincerely,

(name as shown at top right of document)

cc: (name(s) if applicable)

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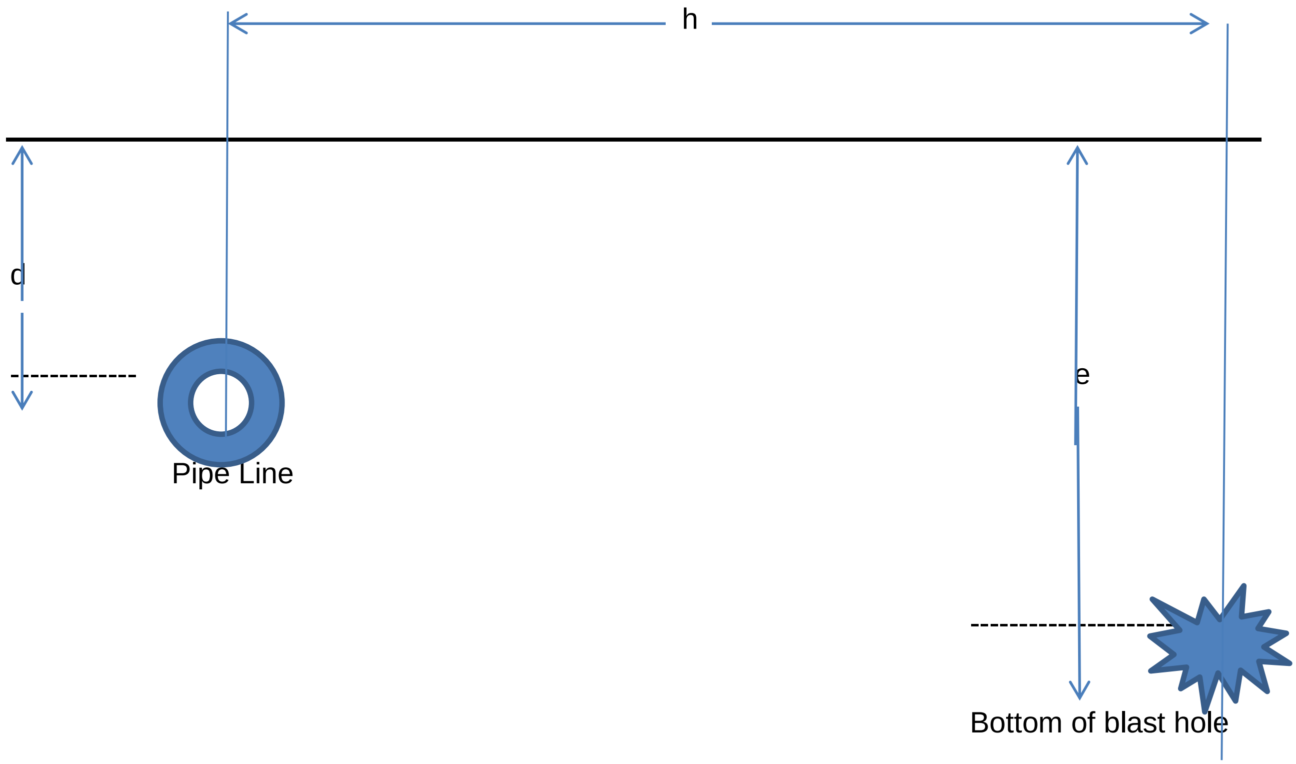
EXHIBIT C
(1 of 1)



Allowable blast hole equation: $e \leq d + \frac{1}{2} h$; IF e meets this equation, then no qualified blasting engineer review is required. Example: d = 3 feet, e = 10 feet, h = 15 feet --- 10 < 3 + ½(15) --- 10 < 10.5

If e > d + ½ h, then a qualified blasting engineer review is required. Example: d = 3 feet, e = 10, h = 10 feet----10 > 3 + ½(10) ---- 10 > 8

d = depth of pipe at the center line of the pipe

e = depth of blast hole

h = the horizontal distance between the pipe and the blast hole.

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Gas Standard

Distribution Operations

Effective Date: 02/11/2012	Damage to Company Pipeline Facilities	Standard Number: GS 1100.030
Supersedes: 04/01/2011		Page 1 of 14

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Damages to Company pipeline facilities may result in a reportable incident. The procedure to be followed for a reportable incident is contained in the NGD Emergency Manual, Section 4.

2. RESPONSIBILITY

The local leadership team is responsible to see that the requirements of this procedure, and the Emergency Manual are understood and followed. In addition the local leadership team is responsible to see that bills for reimbursement are rendered and collection is pursued in accordance with this procedure.

The local leadership team is responsible for taking corrective action to assure that the condition is made safe and reporting all damage to Company facilities on Form GS 1100.030-2, "Damage to Company Facilities Report," Exhibit A.

Damage caused by Company employees and/or Company contractors shall also be reported on Form GS 1100.030-2. This information is required to be collected for Distribution Integrity Management Program (DIMP) purposes to determine if additional training, revisions to procedures, etc. are required.

3. DAMAGE INVESTIGATION

Instances of damage to Company pipeline facilities shall be promptly investigated to determine the extent of facility damage, to ensure public and employee safety, and to determine whether there is stray gas.

The employee(s) making the initial investigation must be aware that facilities beyond the immediate damaged area could be affected and must be checked for possible leakage. It is possible, as the result of an external force that a main, service line, fitting, etc. can be pulled out of a compression coupling or broken at a collar; for a main or service to be cracked or split; for a valve, gate or stop to be broken; or for a service line to be separated from the main at a location remote from the point of damage. Therefore, a check for gas leakage shall be made at all susceptible locations and in and around all buildings near the damaged area. Action designed to prevent personal injury or property damage shall be taken, such as evacuation of buildings, rerouting of traffic or shutting down the work of a contractor or others working in the vicinity. Refer to GS 1708.070 “Outside Leak Investigation” and/or other leakage investigation procedures (Gas Standard Series 1708 and 1714) for further guidance.

If a hazardous condition exists and additional personnel are required, the employee at the scene shall remain until additional help arrives and in no case go further from the scene than the nearest telephone or mobile radio unit in order to contact the Integration Center.

4. DAMAGE REPORTING AND DATA COLLECTION

Damage shall be reported on Form GS 1100.030-2, "Damage to Company Facilities Report," in accordance with the instructions contained within Exhibit A, to facilitate data entry into the applicable WMS Job Order (if applicable) and to address the following.

a. Provide data for evaluating and developing facility protective procedures.

b. Document events for subsequent governmental reports, if required.

c. Provide complete documentation to support accurate facility damage billing and collection.

Form GS 1100.030-1 “Facility Damage Pouch,” Exhibit B, or in Columbia Gas of Virginia an equivalent checklist, shall be used to keep records, photos and reports (including the original Form GS 1100.030-2 “Damage to Company Facilities Report”) associated with each facility damage. Be sure to fill out and mark all of the required information on the outside of the pouch as the information is gathered and date and sign where applicable before sending the pouch to each responsible department.

The Facility Damage Pouch and all its related contents shall be forwarded to Damage Prevention Support at the following address:

Columbia Gas / NiSource
Attn: Damage Prevention Support
3101 North Ridge Road, East
Lorain, OH 44055

NOTE: CGV may be forwarded to Damage Prevention Support by electronic transmittal.

This information will be used as the billing source documentation.

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5. USE OF O&M ACCOUNTS

The appropriate Operation and Maintenance (O&M) Accounts shall be used for damage repairs which do not require the installation, replacement or abandonment of a Property Unit in accordance Work Management System (or equivalent) coding.

All labor for Company personnel is to be charged to the appropriate accounts per Work Management System coding.

6. USE OF CONSTRUCTION AND RETIREMENT CAPITAL JOB ORDERS

A capital Job Order is required whenever a property unit is installed. Examples of property units are shortstopps, valves (2" or over), services, sections of main (unless like kind and size and less than 50 feet), etc. A Retirement Job Order is required whenever a Property Unit is removed from service.

Job Orders shall be processed in accordance with applicable procedures.

7. BILLING FOR PROPERTY DAMAGE

Bills rendered for third party facility damages shall be processed by the appropriate billing organization (currently Damage Prevention Support). The billing organization is responsible for making billing decision, verifying entry of labor, materials and other miscellaneous charges, executing the 2412, 2413 or 3442 job orders, and rendering third party facility damage invoices. The Damage Prevention Support billing organization will partner with the local leadership team, as necessary, for accurate decisions and complete billing documentation.

When charges are accumulated through a capital job order, the Damage Prevention Support should render the MRA bill based on the "Total Estimate" shown on the Job Order(s) to expedite billing and collection.

8. DELINQUENT COLLECTIONS

Delinquent facility damage accounts are pursued and litigated by the appropriate facility damage billing organization.

9. REPORTING OF GAS LOSS

Form GS 1714.010-1, "Distribution Plant Inspection and Leakage Repair (DPI)", is to be completed to report gas lost during third party facility damages. Original Form GS 1714.010-1 is to be retained at local operating area with one of the duplicate pages or a copy enclosed in the Facility Damage Pouch which is sent to the billing organization.

Physical details regarding the damage are documented on Form GS 1100.030-2. Gas loss calculations are completed by Damage Prevention Support and verified by Engineering if calculated loss is 50 MCF or greater.

10. NOTIFICATION OF NON-BILLED OCCURRENCE

When it is determined that damages to pipeline facilities could be billed, but are not billed for an acceptable reason, a letter similar to Exhibit C should be sent to the excavator.

11. RECORDS

Records shall be maintained by Damage Prevention Support.

**EXHIBIT A
(1 of 8)**

Instructions for Form GS 1100.030-2 “Damage to Company Facilities Report”

****

The first set of information will appear on the work management job order. When using Form GS 1100.030-2, this information will be used to match Form GS 1100.030-2with the work management job order.

NOTE: For CMA, use current WOMS number until CDC WMS is implemented.

1. WMS JO# - This is for the job order that is considered the primary job order. An example would be, if the main was damaged, the 2412 job order is considered the primary job order.

   - 2412 – MAIN DAMAGE
   - 2413 – COMPANY SERVICE LINE DAMAGE
   - 3442 – METER AND REGULATOR DAMAGE

2. DATE – Date you are doing the work/repairs.

3. LOCATION# - TCC where the damage occurred.

4. DAMAGE LOCATION – City, State, & Zip Code – Where the damage occurred.

5. MAP # - Indicate map number of where the damage occurred.

****

RELATED JOBS

6. JOB ORDER NUMBER & JOB TYPE – Should be filled out with all the jobs that are related to this damage. An example would be a PR or EMER/2116 that was taken to investigate, or DIS orders that were taken to turn the gas back on to the customers if any were off due to the damage.

7. □ REGULAR HOURS:(1x) HRS □ OVERTIME HOURS:(1.5x) HRS □ OVERTIME HOURS:(2x) HRS– Should be marked according to when you were out on the call. This will have no bearing on your pay, only the dollar value being accumulated for the cost of the damage.

****

GENERAL INFORMATION

8. *TYPE OF FACILITY – Notice there is an asterisk. This means that you must choose only one (1) box below that applies. If the main was damaged, you would select “2 – Main.”

9. *MATERIAL – See the asterisk; again choose only one (1) box below that applies. Select “P – Plastic” if a plastic facility was damaged. Select “ST – Steel Treated” if the damage involved a coated steel facility.

10. LINE SIZE – Indicate the size of line that was damaged.

11. DEPTH OF COVER – Indicate the depth of the line by “inches.” If the damaged facility is located above ground, this field would not apply or indicate “0.”

12. YEAR INSTALLED – Indicate the year the facility was installed, if known.

13. GAS LOST – Indicate yes or no. If you select “YES,” then other fields will be required in the GAS LOST Section of this form.

EXHIBIT A
(2 of 8)

DAMAGE DETAILS:

14. DPI NUMBER – Indicate the associated DPI number from Form GS 1714.010-1 "Distribution Plant Inspection and Leakage Repair (DPI)," if applicable.
15. DAMAGE DATE – Indicate the date that the damage occurred. If unknown, please mark "Unknown."
16. DAMAGE TIME – Indicate the time of damage in military time. This field is required when the damage date is known.
17. REPORTED BY – Indicate the name of "who" called in to report the damage, such as police, fire dept., or private individual, etc.
18. REPORTED DATE – Indicate the date that the damage was called in.
19. REPORTED TIME – Indicate the time called in, in military time.
20. REPORTED TO – Indicate the individual's name of who in our company received the call.
21. TIME OF ARRIVAL – Indicate the time of day (in military time) that the First Company Employee arrived at the damage site.
22. TIME MADE SAFE – Indicate the time of day that adequate precautionary measures were completed. Adequate precautions should be defined as action to reasonably ensure the public's safety. Note that this possibly could be earlier than the time of arrival. An example would include a service line that was cut and the party causing the damage was able to effectively stop the follow of gas by sealing a low pressure line with rags. In the case of damage with no gas loss, such as coating damage, report the "Time Made Safe" the same as "Damage Time."
23. # OF CUST INTERRUPTED – Indicate the number of customers affected by the outage, which could be one customer for a single service, or several for a main damage.
24. PERIOD OUT OF SVC – Indicate the time that the customer(s) did not have gas available. Examples include main repair, gas back in the main, a service line or setting repair, when we turn bas back on to the customer's home. If the customer needs to make repairs, that is NOT included, because gas WAS available.
25. *TYPE OF ACTIVITY – Notice there is an asterisk. This means that you must choose only one (1) box below that applies. We are looking for what was occurring when the damage occurred, such as "11 – Construction/Maint-Road" or "23 – Outside Force-Motor Vehicle Accident." There are three categories of types of activity: Construction/Maintenance, Natural Forces, and Outside Force. Each of the categories has subcategories to further define the type of activity that was occurring when the damage occurred. "31 – Unknown/Other" should only be used if none of the category-subcategory choices fit, and if used, it requires additional comments with a detailed explanation.

**EXHIBIT A
(3 of 8)**

26. *CAUSE OF DAMAGE - Notice there is an asterisk. This means that you must choose only one (1) box below that applies. We are looking for the root cause of the reason that the damage occurred. See below for further explanation of choices.

    A – Excavation-Failed to Notify One-Call: Select this if one-call was not notified, if one-call notification time was insufficient, or if one-call ticket expired.

    B – Excavation-Locating Error: Select this if the locate marks were incorrect due to an error by the locator or if line was not marked although the locator had adequate records.

    C – Excavation-Excavator Error: Select this if the excavator did not expose the facility by hand or if the excavator used mechanical equipment within the tolerance zone.

    D – Excavation-Poor Records: Select this if the company had poor records that mislead the locator. Additional comments are required with a detailed explanation.

    E – Natural Forces: Select this if the damage was caused by earth movement, frost, lightning, rain, wind, snow, or ice.

    F – Other Outside Force: Select this if the damage was caused by something other than one of the other choices, and if used, it requires additional comments with a detailed explanation.

****

LINE MARKINGS:

27. *LOCATE REQUESTED - Notice there is an asterisk. This means that you must choose only one (1) box below that applies. If you select "1 – Yes, Via One-Call" or "2 – Yes, Other Method," then the "One Call Ticket Number" is required.

28. FACILITY LOCATED – Indicate yes or no. If you select "YES," you will need to fill in the majority of the rest of this section. If you select "NO," then you may move on to the next section.

29. ONE CALL TICKET NUMBER – When locate requests are called through the One-Call Center, the requests are assigned a ticket number.

30. *HOW FACILITY LOCATED - Notice there is an asterisk. This means that you must choose only one (1) box below that applies. Mostly, facilities are located though a line locator. However, select "2 – Other or Above Ground" it is apparent that the facility exists above ground.

31. *HOW FACILITY MARKED - Notice there is an asterisk. This means that you must choose only one (1) box below that applies. Indicate what was used to "mark" the facility for the locate request.

32. MARKERS IN TOLERANCE ZONE - Indicate yes or no based on the applicable state one-call law.

33. IF NO, MARKS HOW FAR OFF - If the answer to "32. MARKERS IN TOLERANCE ZONE" is "NO," then indicate distance in feet and inches that the locate marks were from the centerline of the facility.

34. DIST TO NEAREST MARK - Indicate the distance in feet and inches from where the damage occurred to where we have our facility marked (whether our facility was marked correctly or not). This could also be a line marker if it is closer than where we had marked for the locate request.

35. CONTRACT LOCATOR NOTIFIED OF DAMAGE – Indicate yes or no. The contract that we have with external locating companies requires us to notify them anytime a damage occurs on a line that they located for us.

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(4 of 8)

REPAIRS:

36. *REPAIR TYPE – Notice there is an asterisk. This means that you must choose only one (1) box below that applies. Select if repairs were permanent or temporary.
37. TEST FOR SECONDARY DAMAGE – Indicate yes or no.
38. PICTURES TAKEN – Indicate yes or no. MAKE SURE PICTURES INDICATE THE APPROPRIATE DATE AND TIME. Digital pictures are preferred (disposable cameras – a last resort). Download pictures to a common network damage prevention drive. Refer to damage prevention training for photography tips.
39. PICTURES STORED NETWORK DRIVE – Indicate yes or no.
40. PICTURES TAKEN BY – Indicate the person that took the pictures.
41. SKETCH ATTACHED – Indicate yes or no. Attach a separate sketch if DPI sketch or pictures do not adequately represent the information related to the damage.
42. RECORDS CORRECTIONS SUBMITTED – If within the DAMAGE DETAILS Section of this form, the CAUSE OF DAMAGE was determined to be “D – Excavation-Poor Records,” most likely the service line record correction, a map correction, etc. will be required. If so, check the appropriate box when the correct has been made or submitted. Select “N/A” for “not applicable” if a records correction is not needed.

****

DAMAGING PARTY: This is WHO damaged our facility, not necessarily who is responsible. If we do not know who cause the damage, you must mark unknown.

43. *RESPONSIBILITY – Notice there is an asterisk. This means that you must choose only one (1) box below that applies. This is the type of party that damaged our facility, such as “11 – Company Crew (1st Party),” “17 – Private Individual,” etc.
44. COMPANY NAME – Name of COMPANY who damaged our facility.
45. INDIVIDUAL NAME – Name of the person who damaged our facility or the name of the person working for the company listed above.
46. VEH. LIC. PLAT NO. – License plate number of vehicle at damage site.
47. STATE – State of license plate.
48. LOCATED AT – The damaging party’s address.
49. CITY, STATE, ZIP CODE – All are required fields that need gathered if at all possible.
50. OFFICE/HOME PHONE – Office or home phone of company that damaged our facility is preferred, as cellular phones are not traceable.
51. CELL PHONE – Cell phone of individual who damaged our facility or the supervisor of the individual who damaged our facility. This is helpful for future contacts.
52. E-MAIL ADDRESS – E-mail address of individual who damage our facility or the supervisor of the individual who damaged our facility. This is helpful for future contacts.
53. INSURANCE NAME & INSURANCE ADDRESS – Insurance name and address of the damaging party.

EXHIBIT A
(5 of 8)

GAS LOST:

54. DAMAGE HOLE SIZE & UNITS – Indicate the size of hole at the damage. If the pipe is severed such as a 2" service or if the damage is circular, then you would indicate 2" and check the units "DIAMETER-IN." If the damage is not circular, then indicate the damage dimensions, such as 1" x 3" and check "AREA-SQ.IN."
55. HOW LONG DID GAS BLOW? – Indicate the total amount of time (in hours and minutes) that the gas blew, with or without restriction.
56. LINE SIZE – Indicate the size of the pipe at the damage location.
57. *MATERIAL - Notice there is an asterisk. This means that you must choose only one (1) box below that applies. Select "P – Plastic" if a plastic facility was damaged. Select "ST – Steel Treated" if the damage involved a coated steel facility.
58. STABLE SUPPLY PRESSURE - Indicate a known supply pressure close to the damage location.
59. MAOP – Indicate the piping system maximum allowable operating pressure (MAOP).
60. BLOWING OPEN – Indicate yes or no.
61. WAS GAS LOSS RESTRICTED – Indicate yes or no.
62. IF YES, HOW – Explain in detail about the restriction so that gas loss can be figured accurately.
63. HOW LONG RESTRICTED – Indicate in hours and minutes of how long the gas loss was restricted.
64. EXCESS FLOW VALVE – Indicated yes or no if an excess flow valve activated to restrict the gas loss.
65. IF MAIN, DISTANCE TO INTERSECTION OR MAPPABLE FEATURE – Measure the distance (in feet) from the damage to the nearest intersection or critical valve, etc. Also, indicate this distance on the sketch or DPI sketch.
66. IF SERVICE, DISTANCE FROM DAMAGE TO MAIN – Measure the distance (in feet) from damage to main.

NOTE: THE MAIN AND SERVICE MEASUREMENTS (Items 65 & 66) ARE VERY IMPORTANT! This is how the system determines the pressure at the damage site and affects the amount of gas lost.

****

COMMENTS:

67. ADDITIONAL FACTS OR COMMENTS – All comments that are pertinent and apply to the "damage only" should be listed. Most often, the more comments the better!! Keep in mind that records could be pulled in a dispute, or if we go to court, so we want only the applicable FACTS! We could list other comments in the execute side of the job order that do not apply directly to the damage itself (e.g., specific repair information).

    Other comments that apply to the damage:

    - If your time of arrival was more than 60 minutes from the time the call was received, you must explain the reason for delay in comments (e.g., PUCO Emergency Response Report).

      Examples are:

      - Weather

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- Distance
- Traffic
- Leak Prioritization
- Etc.

68. 1st RESPONDER NAME (PRINT) & (SIGNATURE) – Print name of 1st responder to the damage site. 1st responder adds signature on “signature” line.
69. 2nd RESPONDER NAME (PRINT) & (SIGNATURE) - Print name of 2nd responder to the damage site. 2nd responder adds signature on “signature” line.
70. FIELD OPERATIONS LEADER (FOL) ON SITE – Indicate yes or no.
71. HRS/MINS ON SITE – Indicate the total time in hours and minutes that the Field Operations Leader was working on the facility damage.
72. FOL FACTS OR COMMENTS - All comments that are pertinent and apply to the “damage only” should be listed. Most often, the more comments the better!! Keep in mind that records could be pulled in a dispute, or if we go to court, so we want only the applicable FACTS! We could list other comments in the execute side of the job order that do not apply directly to the damage itself (e.g., specific repair information).
73. FIELD OPERATIONS LEADER NAME & SIGNATURE – Print Field Operations Leader name that was on site. FOL on site adds signature on “signature” line.
74. FIELD ENGINEERING ON SITE – Indicate yes or no.
75. HRS/MINS ON SITE – Indicate the total time in hours and minutes that Field Engineering was working on the facility damage.
76. FIELD ENGINEERING FACTS OR COMMENTS - All comments that are pertinent and apply to the “damage only” should be listed. Most often, the more comments the better!! Keep in mind that records could be pulled in a dispute, or if we go to court, so we want only the applicable FACTS! We could list other comments in the execute side of the job order that do not apply directly to the damage itself (e.g., specific repair information).
77. FIELD ENGINEER NAME & SIGNATURE – Print Field Engineer name that was on site. Field Engineer on site adds signature on “signature” line.
78. COMPANY/CONTRACT LOCATOR ON SITE – Indicate yes or no.
79. COMPANY/CONTRACT LOCATOR COMMENTS – Write all comments made by the locator that are pertinent and apply to the damage only. Most often, the more comments the better!! Keep in mind that records could be pulled in a dispute, or if we go to court, so we want only the applicable FACTS! We could list other comments in the execute side of the job order that do not apply directly to the damage itself (e.g., specific repair information).
80. NAME – Print locator name that was on site, if known.
81. DAMAGING PARTY COMMENTS – Write any quotes or comments made by the damaging party.
82. NAME & TITLE – Print name of person from damaging party that made comments, if known. Print title of person from damaging party that made comments, if known.

NiSource

Distribution Operations

Gas Standard

Effective Date: 02/11/2012	**Damage to Company Pipeline Facilities**	Standard Number: **GS 1100.030**
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EXHIBIT A
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DAMAGE TO COMPANY FACILITIES REPORT

WMS JO# ________-______1______-______ DATE: ______2______ LOCATION#: ______3______

DAMAGE LOCATION: ______________ ______4______________________ ______________

CITY ______________________ STATE ________ ZIP CODE ________-________ MAP #: ______5______

RELATED JOBS

JOB ORDER NUMBER	JOB TYPE	JOB ORDER NUMBER	JOB TYPE	JOB ORDER NUMBER	JOB TYPE
6					

☐ REGULAR HOURS:(1x) HRS 7 ☐ OVERTIME HOURS:(1.5x) HRS ☐ OVERTIME HOURS:(2x) HRS

GENERAL INFORMATION

*TYPE OF FACILITY: 8
☐ 1 - Plant Regulator
☐ 2 - Main
☐ 3 - Service Line
☐ 4 - Cust. Meter and/or Regulator
☐ 5 - Building
☐ 6 - Other (Comments Required on Reverse)

*MATERIAL: 9
☐ CI - Cast Iron
☐ CU - Copper
☐ OT - Other
☐ P - Plastic
☐ PI - Plastic Insert
☐ S - Steel
☐ ST - Steel Treated
☐ WI - Wrought Iron

LINE SIZE: ______10______
DEPTH OF COVER: ______11______ IN.
YEAR INSTALLED: ______12______
GAS LOST: ☐ YES ☐ NO 13

DAMAGE DETAILS

DPI NUMBER: ______14______ DAMAGE DATE: ______15______ DAMAGE TIME: ___16___HR: ______MIN

REPORTED BY: ______17______ REPORTED DATE: ______18______ REPORTED TIME: ___19___HR: ______MIN

REPORTED TO: ______20______ TIME OF ARRIVAL: ___21___HR: ______MIN TIME MADE SAFE: ___22___HR: ______MIN

OF CUST INTERRUPTED: ______23______ PERIOD OUT OF SVC: ______24______

*TYPE OF ACTIVITY: 25
☐ 11 - Construction/Maint-Road
☐ 12 - Construction/Maint-Sewer
☐ 13 - Construction/Maint-Utility
☐ 14 - Construction/Maint-Private Property
☐ 15 - Construction/Maint-Demolition
☐ 18 - Natural Forces-Earth Movement
☐ 19 - Natural Forces-Frost
☐ 20 - Natural Forces-Lightning
☐ 21 - Natural Forces-Rain/Wind/Snow/Ice
☐ 23 - Outside Force-Motor Vehicle Accident
☐ 24 - Outside Force-Intentional/Vandalism
☐ 25 - Outside Force-Electrical Arcing
☐ 26 - Outside Force-Maritime Vessel Operations
☐ 27 - Outside Force-Fire/Explosion (Non-Gas Related)
☐ 28 - Outside Force-Previous Damage
☐ 29 - Outside Force-Sewer Clean Out
☐ 31 - Unknown/Other (Comments Required on Reverse)

*CAUSE OF DAMAGE: 26
☐ A - Excavation-Failed to Notify One-Call
☐ B - Excavation-Locating Error
☐ C - Excavation-Excavator Error
☐ D - Excavation-Poor Records (Comments Required on Reverse)
☐ E - Natural Forces
☐ F - Other Outside Force (Comments Required on Reverse)

LINE MARKINGS

*LOCATE REQUESTED: 27
☐ 1 - Yes, Via One-Call
☐ 2 - Yes, Other Method
☐ 3 - No, or N/A

28 FACILITY LOCATED: ☐ YES ☐ NO ONE CALL TICKET NUMBER: ______29______

*HOW FACILITY LOCATED: 30
☐ 1 - Line Locator
☐ 2 - Other or Above Ground

*HOW FACILITY MARKED: 31
☐ 1 - Exposed
☐ 2 - Permanent Markers
☐ 3 - Temp. Stakes or Paint
☐ 4 - Oral
☐ 5 - Other
☐ 6 - N/A

32 MARKS/MARKERS IN TOLERANCE ZONE: ☐ YES ☐ NO
IF NO, MARKS HOW FAR OFF: ___33___FT. ______IN.
DIST TO NEAREST MARK: ___34___FT. ______IN.
35 CONTRACT LOCATOR NOTIFIED OF DAMAGE: ☐ YES ☐ NO

REPAIRS

*REPAIR TYPE: 36
☐ 1 - Permanent
☐ 2 - Temporary

TEST FOR SECONDARY DAMAGE: 37 ☐ YES ☐ NO
PICTURES STORED NETWORK DRIVE: ☐ YES ☐ NO 39
SKETCH ATTACHED: 41 ☐ YES ☐ NO

PICTURES TAKEN: 38 ☐ YES ☐ NO
PICTURES TAKEN BY: ___40___
42 RECORDS CORRECTIONS SUBMITTED: ☐ YES ☐ NO ☐ N/A

DAMAGING PARTY

*RESPONSIBILITY: 43
☐ 11 - Company Crew (1st Party)
☐ 12 - Company Contractor (2nd Party)
☐ 13 - Municipal/State Crew
☐ 14 - Municipal/State Contractor
☐ 15 - Other Utility Crew
☐ 16 - Other Utility Contractor
☐ 17 - Private Individual
☐ 18 - Private Contractor
☐ 23 - Natural Forces
☐ 25 - Unknown
☐ 28 - Other

COMPANY NAME: ______44______
INDIVIDUAL NAME: ______45______ VEH. LIC. PLATE NO. ___46___ STATE ___47___
LOCATED AT: __________ ______48______ ______
CITY ______49______ STATE ______ ZIP CODE ________-________
OFFICE/HOME PHONE: (______) ___50___ CELL PHONE: (______) ___51___
E-MAIL ADDRESS: ______52______
INSURANCE NAME: ______53______
INSURANCE ADDRESS: ______________________

*Choose One (1) Box Only

Form GS 1100.030-2 (02/12)

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GAS LOST

DAMAGE HOLE SIZE: 54 UNITS: ☐ DIAMETER (IN.) ☐ AREA (SQ.IN.) HOW LONG DID GAS BLOW? 55 HR: ______ MIN

LINE SIZE: 56 *MATERIAL: 57 STABLE SUPPLY PRESSURE: 58 MAOP: 59
- ☐ CI - Cast Iron
- ☐ CU – Copper
- ☐ OT – Other
- ☐ P – Plastic
- ☐ PI - Plastic Insert
- ☐ S – Steel
- ☐ ST - Steel Treated

60 BLOWING OPEN: ☐ YES ☐ NO 61 WAS GAS LOSS RESTRICTED: ☐ YES ☐ NO

IF YES, HOW: 62

HOW LONG RESTRICTED: 63 HR: ______ MIN 64 EXCESS FLOW VALVE: ☐ YES ☐ NO

IF MAIN, DISTANCE TO INTERSECTION OR MAPPABLE FEATURE: 65 FT. IF SERVICE, DISTANCE FROM DAMAGE TO MAIN: 66 FT.

COMMENTS

ADDITIONAL FACTS OR COMMENTS:

67

1st RESPONDER NAME: 68 (PRINT) (SIGNATURE) 2nd RESPONDER NAME: 69 (PRINT) (SIGNATURE)

FIELD OPERATIONS LEADER (FOL) ON SITE: ☐ YES ☐ NO 70 HRS/MINS ON SITE: 71 HR ______ MIN FOL FACTS OR COMMENTS:

72

FIELD OPERATIONS LEADER NAME: 73 SIGNATURE: ______

FIELD ENGINEERING ON SITE: ☐ YES ☐ NO 74 HRS/MINS ON SITE: 75 HR ______ MIN FIELD ENGINEERING FACTS OR COMMENTS:

76

FIELD ENGINEERING NAME: 77 SIGNATURE: ______

COMPANY/CONTRACT LOCATOR ON SITE: ☐ YES ☐ NO 78 COMPANY/CONTRACT LOCATOR COMMENTS:

79

NAME: 80

DAMAGING PARTY COMMENTS:

81

NAME: 82 TITLE: ______

*Choose One (1) Box Only

Form GS 1100.030-2 (02/12)

Effective Date: 02/11/2012	Damage to Company Pipeline Facilities	Standard Number: **GS 1100.030**
Supersedes: 04/01/2011		Page 13 of 14

EXHIBIT B

FORM GS 1100.030-1 (01-12)

FACILITY DAMAGE POUCH

1) Field-Damage Information
Date of Damage ______________________________

Address ______________________________

Job # ______________________________

Dpi # ______________________________

(Copy of both sides, list materials w/ stock symbol numbers, vehicles, equipment, provide meal/rental receipts)

Pre-excavation One Call Ticket# ____________________

Contract Locate Ticket# ____________________

Columbia Pictures yes/no - V-drive / enclosed (circle)

WMS Facility Damage (Form GS 1100.030-2) ________________

Mapping Correction Needed: YES or NO *Form GS 2610.040-1* (circle)

Completed by ______________ Date____________

2) Required Packet Information
DPI (front and back *w/ all materials listed*)

WMS hard copy damage Form GS 1100.030-2

Copy of Work Request

Digitial Pictures

Copy of new tap card/survey card for mapping/records update
(If necessary, update CSL records via MDT)

Police Report (if auto accident)

Non-crew labor hours (FOL, OCM, Comm) (Form GS 1100.030-2)

WMS Report- # straight hours, # OT hours per employee

Virginia Only Form DPA-1 (circle) YES or NO

3) 10 Day Exception: YES or NO (CIRCLE)
Type of Exception: CAP JO, GAS LOSS, TEMP REPAIRS or OTHER (CIRCLE ONE)
If yes, list exception comments below. Please include who is handling the exception. IE…Engineering, local area, etc…
Comments: ______________________________

____

____

____

Received Date:______________________________
Assigned to: ______________________________

4) FOL - Damage Approval
Received Date:______________________________

Map Correction Required: Form GS 2610.040-1 YES or NO (circle)
(FOL and CREW are accountable for map corrections/CSL updates)

Bill for Damages: YES or NO (On packet, NOT in WMS)

Include specific comments relative to damage: ____________
____
____

Approved by: ______________________________
Date Forwarded: ______________________________

5) Damage Prevention & Recovery - Damage Billing

Received Date:______________________________
Letter Sent to Damager with Inserts: ________________

Effective Date: 02/11/2012	Damage to Company Pipeline Facilities	Standard Number: **GS 1100.030**
Supersedes: 04/01/2011		Page 14 of 14

EXHIBIT C

[*Company Letterhead*]

Date

[*Name & Address*]

Subject: Report of Damage at [*address*]

The purpose of this letter is to bring your attention an incident that damaged a Columbia Gas of (*State*), facilities. The estimated cost to repair damages is $ [*XXXX*]. If the damage investigation determines you are responsible, you will receive a bill.

Damage inflicted on a natural gas facility can result in an unsafe condition for excavator personnel, the public, gas consumers and gas company personnel. Additionally, interrupted gas service creates hardships for gas consumers. Therefore, it is essential that all excavation, construction and demolition activities be carried out so as to prevent damage to utility facilities.

Your cooperative effort in preventing future damages is requested. To this end, the attached Safety Bulletin provides a means to notify Columbia Gas of [State], of planned excavation. It is imperative that you call [*your state one call center phone number*] so all underground facilities can be marked in advance of an excavation.

Sincerely,

Attachments

[*Title of specific Safety Bulletin*]

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/02/2015	**Damage Prevention – Using Trenchless Technology**	Standard Number: **GS 1100.050**
Supersedes: 03/27/2013		Page 1 of 5

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☐ COH
	☑ CMA	☑ CPA

1. GENERAL

This standard applies to the use of certain types of trenchless technology, by the Company or its contractors, such as directional drilling, boring, augering, jacking, driving or other mechanical means to construct transmission lines, distribution mains, and/or service lines, which precludes the need to make an open trench excavation. However, trenchless technology such as pipeline insertion or pipe lining may not require the precautions indicated in this standard.

Either the Company or its contractor (determined by who is actually using trenchless technology), in accordance with all applicable contracts, is responsible for ensuring that adequate clearance is maintained between the proposed underground facility and other existing facilities.

2. PRIOR TO CONSTRUCTION

2.1 Transmission Lines and Distribution Mains

For transmission line and/or distribution main construction projects, Engineering should consult with Construction to preplan the project if the use of trenchless technology is anticipated.

2.2 All Pipeline Facilities

The following steps shall be completed prior to using trenchless technology.

a. Notify the one-call agency and all non-participating utilities in accordance with the applicable state requirements to locate all underground facilities.

b. Perform a site investigation, including facilities that have not been located or are difficult to locate accurately, which would typically cross the proposed bore path, particularly sewer (i.e., sanitary and storm) facilities.

   The site investigation may include, but is not limited to the following tasks.

   1. Re-notify the one-call agency or non-participating utility, if appropriate.
   2. Call the utility owner (e.g., city, township, etc.) directly to discuss the

project and request a physical locate of facilities in the field. If a physical locate is not possible, request a copy of any available records.

3. Communicate with property owners or developer about the location of sewer connections, septic systems, drains (downspout, footer, French), etc.

4. Research as-built records.

5. Perform an onsite investigation to locate cleanouts and/or manholes to determine the physical location of a sewer line. Access to cleanouts and manholes can also allow locating by electronic means (e.g., the insertion of metallic fish tape) prior to the physical spotting of the sewer.

6. Employ the use of a video camera to locate sewer and drain connections, if appropriate.

Communicate potential issues resulting from the site investigation to the entity performing the trenchless technology operations.

c. Establish the location of the bore path. Plan for adequate clearances between the proposed and existing facilities. Consider the clearance to be the <u>actual distance from the outside edge of the existing structure to the closest edge of the largest diameter back reamer or outside edge of other types of boring equipment (i.e., pushing machine, hole hog, etc.)</u>

If clearance is less than 24 inches, then plan to use hand excavation, vacuum excavation, or other non-invasive equipment to expose the existing facility in order to ensure that the proposed facility installation does not damage the existing facility.

d. Plan a bore that will minimize secondary damage (e.g., road heaving) which might result from the force generated by a pneumatic piercing tool or directional boring fluid. The bore should be planned at the proper depth for the size of bore hole, considering soil type and existing soil conditions.

For conventional boring, the annular space between the pipe and the bore hole should be kept to a minimum to prevent caving. For 3 inches and smaller pipe or casing, a bore hole no greater than 5 inches diameter is recommended. For 4 inches and larger pipe or casing, a bore hole no greater than the next larger pipe size is recommended.

e. Plan to set up equipment properly to ensure that bore equipment stakes and grounding rods are installed at a safe distance (24 inches from the outside edge of the underground facility) from the marked location of underground facilities and that the drill head locating device is functioning properly and within its specification.

Also when planning equipment set up, ensure that adequate clearance can be maintained between construction equipment and above ground or overhead facilities.

Trenchless technology should not be used if any known underground facility location and depth crossing the proposed bore path cannot be determined.

3. DURING CONSTRUCTION

Determine the location and depth of known underground facilities that have been located or found during the site investigation (e.g., sewer laterals) which are in the path of the proposed work.

When excavating within the tolerance/safety zone, which includes the width of the facility plus 24 inches on either side of the outside edge of the underground facility, the excavator shall exercise at all times such reasonable care as is necessary to protect the underground facility from damage. Except for the initial pavement removal, in order to locate and identify an underground facility, the excavator shall excavate by methods limited to hand digging, potholing, vacuum excavation, or other non-invasive methods accepted in the industry which will not affect the integrity of the underground facility.

All spotting of facilities should take place within the proposed bore path, or if impractical, as close to the proposed bore path as possible. Note that significant grade changes can occur in just a few feet.

Potholes should be excavated along the bore path (in a manner to prevent damage) to determine the actual distance from the outside edge of the existing structure to the closest edge of the largest diameter back reamer or outside edge of other types of boring equipment (i.e., pushing machine, hole hog, etc.). Electronic locating equipment should be used to verify the bore path location between potholes or if clearance is 10 feet or more.

The potholes should be used to visually check the drill head or other boring equipment as it passes through the pothole and during backreaming operations to assure the bore is progressing as planned, with no adverse effects to other active underground facilities. If the depth indicated by the bore locating device is not on track as planned, evaluate the situation and proceed with acceptable practices. For example, acceptable practices may include the following:

a. continue boring only if significant clearance from existing facilities can be maintained,

b. cease boring until the pothole can be hand excavated further to maintain a visual inspection of the drill head and proximity of existing facility, or

c. cease boring, and restart or redirect the bore.

Where potholes cannot be reasonably excavated (e.g., river or creek, interstate, railway crossings, etc.), electronic locating equipment shall be used to verify the bore path location is on track as planned.

3.1 Crossing Existing Facilities

Potholes should be excavated over known underground facilities that will be crossed by the proposed bore path and under if the proposed bore path is crossing beneath the existing facility, unless video equipment is utilized to determine location and depth.

If there is less than 12 inches of clearance, appropriate measures shall be taken to prevent damage to either facility (e.g., installation of an approved insulation material to provide permanent separation, installation of rock shield, etc.)

3.2 Paralleling Existing Facilities

When using trenchless technology parallel to existing underground facilities, potholes should be excavated along the bore path to ensure that the bore is on track as planned. At a minimum, potholes should be excavated at the entrance and exit points of the proposed bore path.

a. When the clearance can be maintained at 10 feet or more, no additional potholes are required.

b. If the clearance is less than 10 feet but greater than 5 feet, additional potholes should be excavated (in a manner to prevent damage) along the bore path at reasonable intervals of approximately:

   i. 50 feet, or

   ii. 25 feet, if near a transmission line or a service connected to a transmission line.

   The direction of the bore path shall be corrected, if necessary, based on the information gained from the potholes.

c. If the clearance is less than 5 feet, the on-site supervisor or Company representative shall assess the risk (based on the type of soil conditions and the size and controllability of the proposed bore) and determine an appropriate clearance, consider a closer pothole interval, and verify the location and clearance of the existing facility. Another option is to discontinue boring in favor of open trenching. Contact the appropriate construction leader or front line leader for guidance, if necessary.

If a municipality or locality prohibits pothole openings within existing pavement, contact the appropriate front line leader. If a resolution is not reached or if a more permanent resolution is needed, refer the issue to the Company's representative responsible for compliance.

4. AFTER CONSTRUCTION

If there is any doubt as to whether sewer facility damage occurred from the use of trenchless technology, then it is recommended that a video camera be used after construction. Any video recordings should be filed with the completed work packet.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Emergency Plan**	Standard Number: **GS 1150.001**
Supersedes: N/A		Page 1 of 3

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.615

1. GENERAL

The purpose of this procedure is to identify the specific requirements for the Company's emergency plan to minimize the hazard resulting from a **gas pipeline emergency**.

Procedures for employees responding to a gas pipeline emergency are contained in the following Company documents:

Columbia Distribution Companies	Emergency Manual
Northern Indiana Public Service Company	Gas Systems Operations Emergency Plan

1.1 Emergency Types

The Company's emergency procedures give direction for prompt and effective response to various emergency conditions, including, but not limited to the following.

a. Gas detected inside or near a building.

b. Fire located near or directly involving a pipeline facility.

c. Explosion occurring near or directly involving a pipeline facility.

d. Natural disaster.

1.2 Emergency Procedures

In a natural gas pipeline emergency or any other type of emergency that may affect the gas transmission and distribution systems, the Company's emergency procedures shall be followed. These procedures specify actions to protect people first, then property.

The emergency procedures provide direction for the following.

a. Receiving, identifying, and classifying notices of events which require immediate response by the Company.

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

c. Actions directed toward protecting people first and then property.

d. Emergency shutdown or pressure reduction in any section of the Company's pipeline system necessary to minimize hazards to life or property.

e. Making safe any actual or potential hazard to life or property.

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

g. Safely restoring gas service after an outage.

h. Conducting an investigation into gas facility failures, if applicable, as soon possible after the end of the emergency in accordance with GS 1652.003 or GS 1652.003(MD) "Program for Investigation of Failures."

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

1.3 Additional Company Requirements

The Company shall:

a. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest version of the emergency plan necessary for compliance with this procedure.

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

c. Review employee activities to determine whether the procedures were effectively followed in each gas pipeline emergency that involves an **incident** or other gas pipeline emergencies deemed significant by the Company.

2. LIASION WITH FIRE, POLICE, AND OTHER PUBLIC OFFICIALS

The Company shall establish and maintain liaison with appropriate fire, police, public officials and outside agencies that might be involved in emergency response. This contact benefits both the outside officials/agencies and the Company by providing information on the following.

a. The types of gas pipeline emergencies for which the Company will notify officials.

b. The Company's ability and resources available to respond to emergencies.

c. How to notify each other in the event of an emergency.

d. The responsibilities and resources of officials and agencies that may respond in the case of an emergency.

e. How the Company and officials can engage in mutual assistance to minimize hazards to life or property.

Informal liaison with these officials at other times is encouraged.

3. MAINTENANCE OF EMERGENCY PROCEDURES

This procedure and the procedures contained within the Company's emergency plan shall be reviewed and updated at intervals not exceeding 15 months, but at least one each calendar year.

4. RECORDS

As a minimum the Company shall document the following.

a. A list of the names of persons who have received a copy of the latest version of the Company's emergency plan.

b. The date when the annual review of the emergency procedures was conducted.

c. Communications with fire, police, or public officials including date, names and titles or people in attendance.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Responding to a Report of a Gas Odor**	Standard Number: **GS 1150.003**
Supersedes: N/A		Page 1 of 1

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605 (b)(11), 192.615 (a)(1), 192.615 (a)(3)(iii)

1. GENERAL

This procedure addresses the prompt response to a report of a gas odor inside or near a building.

2. RECEIVING NOTICE OF A REPORT OF GAS ODOR

For reports of gas odors originating from either customers or the general public, the report can be received by the Company via its Call Centers or Operations dispatch centers.

To originate an order to respond to a report of a gas odor, the following information is requested from the person who is reporting the gas odor.

a. The name of person reporting and a contact telephone number (preferably cell) that will ring at a safe location away from the premises.
b. The address, including city or town, of building or location of the gas odor site.
c. Special directions to get to building or gas odor site (including cross-streets, subdivision, landmarks).
d. Access arrangement to the property, if applicable.

Based on information received, the Company will advise the caller on further action.

3. RESPONDING TO A REPORT OF GAS ODOR

A report of a gas odor is to be responded to immediately. Refer to the GS 1150 series of gas standards and the Company's Emergency Manual for additional requirements.

Gas Standard

Distribution Operations

Effective Date: 12/01/2008	Responses to Potentially Unsafe Situations	Standard Number: GS 1150.005(CG) P&P 511-3
Supersedes: N/A		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
☐ NIFL	☑ CKY	☑ COH
☐ Kokomo Gas	☐ CMA	☑ CPA

REFERENCE Code of Federal Regulations - Title 49 - Part 192 - § 192.615

1. GENERAL

A potentially unsafe situation is an operational condition which field employees may encounter. As part of Columbia's Operator Qualification Plan, OQM7, "Preventing Accidental Ignitions/Damage Prevention/Responding to Abnormal Operating Conditions" (M7), has been developed to prepare affected employees to recognize and respond to unsafe situations. M7 training prepares affected employees not only to react in a positive way, but also in a manner incorporating the employee's knowledge of existing Company procedures.

2. TRAINING

Employees who may be required to respond to potentially unsafe situations (i.e., affected employees) include, but are not limited to:

a. Supervisors who are responsible for emergency actions (including Operations, Integrations Center and Customer Contact Center),

b. all construction and maintenance personnel,

c. Service personnel,

d. those who schedule, assign, or dispatch work, and

e. telephone contact personnel.

2.1 Initial Training

New and transferred employees, who will be assigned to positions which may require a response to potentially unsafe situations, must receive M7 training. Transferred employees who have previously received the initial training program may be exempted from this requirement.

Training shall be conducted within one year of an employee's hiring or transfer.

2.2 Refresher Training

Employees, who may be required to respond to potentially unsafe situations (i.e., affected employees) shall receive refresher M7 training at least once every three (3) calendar years.

3. TRAINING RECORDS

M7 records for Company employees will be maintained in LMS. Contractors shall maintain records in accordance with Operator Qualification record keeping requirements.

NiSource

Gas Standard

Distribution Operations

Effective Date: 08/14/1998	**Reporting and Processing Damage to the Property of Others**	Standard Number: **GS 1150.007(CG)** P&P 525-5
Supersedes: N/A		Page 1 of 5

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
☐ NIFL	☑ CKY	☑ COH
☐ Kokomo Gas	☐ CMA	☑ CPA

REFERENCE None

1. GENERAL

This procedure applies to processing claims or incidents which could give rise to a liability claim against the Company, including notification, claim assignment, and claims processing assistance.

2. DEFINITIONS

2.1 Major Accident/Incident

a. Any accident or incident which is reportable to federal and/or state agencies. (Refer to Emergency Manual)

b. Incidents which may not be reportable as in section “a”, but which involve fatalities, injuries requiring hospitalization for burns, fractures or lost time from work, or, substantial property damage (estimated to be above $10,000).

2.2 Minor Accident/Incident

a. Any accident of incident which may give rise to a claim for less than $10,000 for which the Company is accused of causing the injury /damage or may have liability.

3. NOTIFICATION PROCEDURE

a. All claims or incidents which could give rise to a claim should be reported to the NiSource Claims Reporting System is contacted at 1-877-ENERGY-4 (1-877-363-7494). A claim/tracking number should be obtained and documented. In addition, all major incidents shall be reported to Company legal counsel. Each Company is responsible for establishing a procedure so that all incidents which could give rise to a claim against the Company are reported.

b. Gas related incidents which cause injuries or property damage should be reported through the Emergency Notification System, and, by phone, to Company legal counsel. Assigned counsel shall ensure that federal, state and local agencies and commissions are appropriately notified and that all immediate necessary actions are taken to preserve evidence and mitigate damages.

c. Immediately Report

1. Any ignition of gas connected to a fatality, hospitalization for injuries.
2. Any accident or incident related to the use of gas by a customer such as carbon monoxide poisoning, inhalation of natural gas, over-pressuring of gas lines, or malfunctions of meters or regulators which may be connected with a fatality, hospitalization for injuries or property damage.
3. Any accident or incident related to any other Company activity that may be connected with a fatality, hospitalization for injuries or property damage.
4. All incidents which must be reported to governmental agencies.
5. All other incidents covered in the Emergency Manual.

d. Lawsuit Reporting Requirements

Copies of any and all lawsuits shall be sent to Company legal counsel.

4. INVESTIGATIONS

Investigative materials shall be gathered promptly and forwarded to assigned Company legal counsel. Examples of the kinds of materials likely to be appropriate based on the kind of occurrence are as follows:

a. Gas Related Incidents including explosions, fires, carbon monoxide poisoning, etc.

1. Pressure tests of house lines, service lines and/or Company mains.
2. Odorant level results (Test to be taken after the incident).
3. Combustible Gas Indicator readings: Bar testing around basement, customer lines, company lines, checking sewer basins, etc.
4. Obtain copies of pertinent Company records including the following.
   - Service orders.
   - Leak orders.
   - Customer service line surveys.
   - Meter change records.
   - Service tap cards.

- Maps.
- Consumption and billing records.
- Charts from regulator stations.
- Odorant level test results (tests taken before the incident).

5. Fire and Police Department reports.
6. Sketches and photographs of accident scene.
7. Copies of any and all newspaper articles concerning the incident.
8. List of company employees and/or contractor employees involved either before during or after incident occurred.
9. List of witnesses.
10. A narrative of the chronology of events.
11. Company employee contact who is most familiar with the incident.

b. Incidents resulting in bodily injury or property damage from non-gas related causes.

1. Photographs of alleged hazards (curb box, pavement/sidewalk defects) along with diagrams showing relevant measurements. In photographs demonstrating smaller measurements, use ruler in the photo.
2. Photographs of property damage (trees, lawns, etc.).
3. List of witnesses.
4. Company employee contact who is most familiar with the incident.
5. Name, address, phone number and other relevant information concerning injured person.
6. Address of property damage.
7. Name, address and phone number of property owner.

5. EVIDENCE

5.1 Pertinent Evidence

Preserve items which may be pertinent to an accident /incident, considering the following.

a. Tag all property preserved using an Exhibit Tag, Form C-2344. Ensure that all information required on the form is completed and a copy of the tag is made for the official file which will be maintained by assigned legal counsel or the Company's insurance carrier.

b. Document the chain of custody of all evidence by completing and attaching a new tag each time custody of the evidence changes. A copy of each tag should be maintained for the file as in section a. above. It is preferable to assign custody to only one employee and maintain it in a locked closet.

c. If possible, physical evidence should be protected from contamination by securing it in appropriate containers such as an airtight plastic bag, accompanied by a desiccant or drying agent to minimize exposure to moisture.

5.2 Other Evidence

Consult with the Company attorney concerning incidents which are considered sensitive, especially in cases when information gathered is in contemplation of a claim or litigation. The following guidelines concern other evidence that might be provided.

a. Narrative Reports

Inter-office memoranda or narrative reports which contain sensitive information and/or are prepared at the request of legal counsel should be addressed to the attorney assigned the claim with the following statement written across the top of the first page, "Privileged and confidential, for the advice of counsel."

b. Employee Witnesses

Statements from employees should be taken in all major accidents/incidents. The use of recording equipment is appropriate, although the tape should be preserved, if possible. All statements requested by the Law Department should be labeled "Taken at the direction of Attorney X." Statements of employees are not to be signed except at the direction of the Lawyer in charge or if taken by the Company's insurance carrier and the employee is asked to sign such statements.

c. Public Witnesses

Statements from public witnesses are necessary and appropriate. They should ether be tape recorded or hand written, depending on the nature and circumstances. Signatures should be obtained on statements from public witnesses.

d. Record Requests - Major Incidents

Because of the nature of major incidents, a complete analysis of all records for the entire period of their retention is necessary.

e. Cooperate with Company Insurers

Provide the Company's insurance carrier with all records requested no different than if such records and documents were requested by Company Legal Counsel.

Gas Standard

Distribution Operations

Effective Date: 06/25/1993	Supplier Caused Outage or Damage	Standard Number: GS 1150.009(CG) P&P 525-8
Supersedes: N/A		Page 1 of 1

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
☐ NIFL	☑ CKY	☑ COH
☐ Kokomo Gas	☐ CMA	☑ CPA

REFERENCE None

1. GENERAL

If CDC incurs expenses because of an affiliate or a non-affiliate gas supplier unplanned outage or damage, the Law Department will determine if CDC is eligible for reimbursement.

Reportable incidents caused by an affiliate or a non-affiliate company shall be reported in the same manner as other reportable incidents. (See Emergency Manual, Section 4.)

Operating Centers shall not discuss the reimbursement for expenses with the gas supplier on a local level. When appropriate, the Operating Center shall determine the expenses attributed to the repair and relighting of the affected customer(s) and provide the information to the Law Department. In addition to the cost summary the Operating Center shall provide a brief summary of events leading to the outage or damage.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/11/2014	**Emergency Response – General Guidelines**	Standard Number: **GS 1150.010**
Supersedes: 01/01/2012		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

1. SCOPE

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

These guidelines provide a reference for employees taking action in response to an emergency involving gas facilities. During emergency response, employees must follow all applicable state or federal guidelines, as well as company policies and procedures. All employees must be aware of their qualifications that enable or limit their performance of necessary tasks during an emergency and act accordingly.

Appropriate Personal Protective Equipment (PPE) should always be utilized. Follow all safety procedures when a leak investigation leads to an underground vault or other confined space.

2. GENERAL GUIDELINES

If immediate emergency assistance is needed, request the Company's dispatch center[1] to make the first emergency contacts. In the event such contact cannot be made by the dispatch center, the first responder on site may call fire, police or other emergency services directly using 911.

Record arrival time and report any significant initial observations to the dispatch center such as evidence of fire, explosion, evacuations, police or fire department on the scene, blowing gas, damaged gas facilities, road closings, strong odor of gas, and other external hazards such as damage to other utilities or structures.

Direct all news media inquiries to local Supervision and/or Communications.

2.1 Determine if a Hazardous Situation Exists

Determine if a hazardous situation exists based on the following conditions:

a. escaping or uncontrolled gas,

[1] Depending upon the Company, the dispatch center refers to either the Work Management Center (Indiana) or the Integration Center.

b. results from tests made with leak detection equipment,

c. location of escaping gas and its migration, (follow company procedure for gaining access), and/or

d. other conditions observed at the scene of the reported emergency.

2.2 Determine What Actions Are Necessary

Determine, based upon Company procedures, what actions are necessary to make the condition safe, such as the following.

a. Evacuate.

   1. Coordinate with fire department if they are on the scene.
   2. Make sure buildings are secure to prevent re-entry.
   3. Communicate with evacuees the procedure for re-entry.

b. Direct occupants and bystanders away from the area.

c. Eliminate ignition sources including electric service (Refer to GS 1770.010 "Prevention of Accidental Ignition" for additional guidance).

d. Control escaping gas (e.g., by stopping the flow of gas by closing valves or other means).

e. Ventilate affected buildings.

f. Purge or vent outside leakage (e.g., by removing manhole covers, bar holing, installing vent holes or other means).

g. As needed, establish and monitor the perimeter and check for migrating gas.

h. Notify fire, police or others on site that you are from the gas company and determine who is in charge at the site.

i. Take efforts not to disturb potential evidence at the scene of the fires, explosions and breaches of security.

j. Continue to assess the situation. Update Supervision or the dispatch center and indicate what assistance may be needed.

k. As needed, call for facility locates.

l. As needed, ask fire or police for assistance in controlling traffic.

m. If a line marker or sign is found on-site that indicates another gas pipeline operator's emergency response phone number, they shall be promptly notified.

n. Contact gas control as needed.

Distribution Operations

Gas Standard

Effective Date: 07/01/2012	Guide for Responding to Accidents and/or Incidents	Standard Number: GS 1150.012(CG)
Supersedes: 02/19/1996		Page 1 of 11

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☑ COH
	☐ CMA	☐ CPA

REFERENCE Code of Federal Regulations - Title 49 - Parts 191, 192, 199 and 394; NiSource Anti-Drug and Alcohol Misuse Prevention Program Manual; NGD Emergency Manual

1. DEFINITIONS

Accident is defined as an undesired non-gas related event that results in physical harm to a person or damage to property and is reportable in accordance with Exhibits A and B.

Incident is defined as an undesired event that is or may be gas related and is reportable in accordance with Exhibits A and B.

Investigation or inquiry, is defined as any non-routine examination regarding an accident/incident. It does not include routine police or fire departmental investigations, government audits, compliance reviews or requests for general information conducted under applicable state or federal codes.

Safety-related condition is defined as any gas related condition which might, if left to linger, "constitute an imminent danger," or "potentially cause an incident." (Refer to GS 1020.010 “Safety-Related Conditions - Recognition, Notification, and Reporting.”)

2. EMPLOYEE CONDUCT

Employees shall follow Policies and Procedures and/or the Emergency Manual in responding to accident/incident.

The first employee(s) on the scene has an important function to perform. That function is to take appropriate action necessary "to make the condition SAFE" in order to prevent further injury to persons or damage to property. The employee(s) shall cooperate with and make use of the services provided by fire, police, and emergency personnel.

Evidence discovered, regardless of whether it absolves the Company from responsibility, shall not be discussed with bystanders, victims, relatives or friends of victims, or media personnel. Any questions shall be politely turned aside. (See Section 4, "Non-Media Inquiry.")

Employees shall not provide written statements or accounts to any-one not affiliated with the Company.

Note: There is a valid reason to exercise care. An employee may sign a statement which is believed to be a true account. Later in court, some detail considered relatively minor may turn out to be a critical issue. A slightly different answer to some fact may let the opposing attorney cast doubt upon the truth of the testimony. This is what is known as impeaching a witness.

No property belonging to the Company shall be turned over to a governmental agency or other outside investigators without prior approval of General Counsel or designee.

Employees are to conduct themselves, at the scene of an accident/incident and thereafter, so that they will not unknowingly do serious damage to the defense of claims brought against the Company.

Employees should be advised that penalties can be imposed upon any person submitting false or misleading information to an authorized agent in a government investigation.

Employee conduct shall be guided further by the following:

a. An employee may not be sufficiently knowledgeable to discuss the accident/incident. An attempt to volunteer an opinion as to the probable cause is not prudent. Therefore, no opinion as to the probable cause of any accident/incident is to be given voluntarily.

b. Evidence discovered by an employee shall be made available to the Company rather than "giving aid and comfort to a third party." Certainly, this is the case where the liability is still in doubt.

c. Preliminary information shall be treated confidentially; this gives the Company an opportunity to prepare a defense against claims developing where there is no evidence of negligence on the Company's part.

d. Proper employee conduct gives the Company a better opportunity to evaluate claims where liability on the Company's part is in doubt. Employees' conduct or other factors could very possibly be the difference between a non-suit and costly litigation.

e. Avoid casual and/or unsubstantiated or unintentional remarks which could make reasonable settlements of substantiated claims difficult.

Employees can use the “Auto Accident Guide” (aka “3 Easy Steps to Help You After an Accident” brochure) for gathering data related to a motor vehicle accident. . This form should be stored in the glove compartment of each automobile or truck operated by the Company.

3. MEDIA INQUIRY

The Operations Center Manager, Communications/Public Affairs Department agent or a designated representative shall act as the sole Company spokesperson to the media, to avoid confusion and to promote consistent information. Media inquiries to any other employee shall be directed by that employee to the designated spokesperson.

In the case of a telephone inquiry, effort should be made to ensure that the media is put in contact with the spokesperson as rapidly as possible.

4. NON-MEDIA INQUIRY

An appropriate response for any employee, who is contacted for information related to an accident/incident would be: "I'm sorry, but I can't answer your questions. I suggest you contact (Name of Individual). You may reach him/her at the (Name of Company) office at (Address) or call him/her at (Phone Number)." This shall be the employee's supervisor or the person in charge of the investigation.

5. NOTIFICATION PROCEDURE

The local Operations Centers are to establish a method to handle the reporting of accidents/incidents, both during and after normal working hours. (The Company's Emergency Manual provides guidelines for reporting incidents.)

6. ACCIDENT/INCIDENT FORMS/REPORTS REFERENCE

Exhibit A lists the various types of accidents/incidents with a Code Number for related forms and/or reports.

Exhibit B lists the Code Numbers for the Forms/Reports required and related standards.

7. RELATED PROCEDURES

The standards listed below can assist in the notification and follow-up reporting requirements of accidents/incidents where the Company is or could become involved.

Standard Number	Title
n/a	Emergency Manual, Section 4.00 "Incident Reporting"
GS 1100.030	Damage to Company Pipeline Facilities
HSE 4000.010	Injury and Illness Reporting
GS 1150.007(CG)	Reporting and Processing Damage to the Property of Others
HSE 4300.020	Vehicle Incident Reporting
HSE 4400.020(CG)	Environmental Occurrence Reporting

8. POST-ACCIDENT/INCIDENT ALCOHOL AND DRUG TESTING

Refer to the Emergency Manual Section 6, Form 6.4 "Internal/External Stakeholders Notification List" for the current list of approved facilities to use to perform after-hours drug or alcohol tests.

8.1 Drug Tests

As soon as possible, but no later than 32 hours after a DOT or Kentucky PSC reportable pipeline incident, DOT reportable vehicle accident (if the driver of the commercial motor vehicle receives a citation for a moving traffic violation) or as required by other regulatory bodies, the Company shall drug test each employee whose performance either contributed to the incident or cannot be completely discounted as a contributing factor to the incident. (Refer to Emergency Manual, Section 4.00 “Incident Reporting,” for reportable pipeline incident definitions.) The Company may decide not to test but such a decision must be based on the best information available immediately after the accident/incident that the employee's performance could not have contributed to the incident or that, because of the time between the performance and the incident, a drug test is useless to determine whether the performance was affected by drug use. Refer to the NiSource Anti-Drug and Alcohol Misuse Prevention Program manual for additional guidance on these requirements.

8.2 Alcohol Tests

As soon as possible, but no later than 2 hours after a DOT or Kentucky PSC reportable pipeline incident, DOT reportable vehicle accident or as required by other regulatory bodies, the Company shall alcohol test each employee whose performance either contributed to the incident or cannot be completely discounted as a contributing factor to the incident (Refer to Emergency Manual, Section 4.00 “Incident Reporting,” for reportable pipeline incident definitions.)

The employee that is subject to the post-accident alcohol test must remain readily available for alcohol testing. The employee shall notify the Company in accordance with Section 5 of this procedure if he/she leaves the accident scene prior to the administration of the test. An exception to this notification requirement occurs in instances where the employee must leave the accident scene for purposes of notifying law enforcement or fire department officials or in the event that the employee must seek emergency medical treatment.

If, after 8 hours has expired and the employee in question has not been alcohol tested, the Company shall cease all attempts to alcohol test. The employee is prohibited from consuming any alcohol (including medication that contains alcohol) during the investigatory process until either tested or his/her performance has been discounted as a contributing factor.

If an alcohol test cannot be arranged within 2 hours, reasons will be documented and forwarded to the Manager of Employee Assistance Services. If the test cannot be administered within 8 hours, the same report must be forwarded to the Manager of Employee Assistance Services, per DOT requirements. Refer to the NiSource Anti-Drug and Alcohol Misuse Prevention Program manual for additional guidance on these requirements.

9. POST-INCIDENT REVIEW

9.1 Types of Incidents Requiring Review

Refer to Section 5 of the Emergency Manual for guidelines for conducting a post-incident review.

A special review shall be conducted by the affected Operating Center as soon as practical following a U. S. DOT reportable incident. A review of other major occurrences in which the gas system was adversely affected or jeopardized shall be reviewed. Other major occurrences include, but are not limited to:

a. a natural disaster, such as a tornado or earthquake,

b. fire or explosion caused by escaping gas and producing significant property damage or personal injury,

c. system malfunction or operating error resulting in a large scale outage or overpressuring of a system, and/or

d. other incidents considered to be worthy of review due to significant involvement of fire or police officials, widespread news coverage, or evacuation of schools or public buildings.

9.2 Performance Review

The incident review outline in Section 5 of the Emergency Manual (Form 5.23) should be used to determine if the response was according to the guidelines in the Emergency Manual and whether the Emergency Manual guidelines are appropriate for the emergency encountered.

9.3 Corrective Action

The need to make revisions to the Emergency Manual or improvements in employee training or public liaison may be revealed during the review of emergency incidents. Deficiencies, comments and recommended revisions should be referred to Pipeline Safety & Compliance for consideration. Refer to GS 1014.010 “Periodic Review of Operations and Maintenance Activities” for guidance in requesting revisions.

10. EMERGENCY TRAINING

Personnel with a defined role in emergency response shall be trained as soon as practical after being assigned to an affected position. Refresher training shall be conducted at least once each calendar year, not to exceed 15 months. It is recommended that the training be documented by establishing a WMS Repetitive Task.

Training shall include an orientation to become familiar with reporting requirements, documenting incidents, the location of emergency equipment, procurement of additional manpower, liaisons with public officials, dealing with media, and defining roles during an emergency.

Effective Date: 07/01/2012	**Guide for Responding to Accidents and/or Incidents**	Standard Number: **GS 1150.012(CG)**
Supersedes: 02/19/1996		Page 7 of 11

EXHIBIT A
(1 OF 3)

ACCIDENT/INCIDENT CODE NUMBERS

ACCIDENT/INCIDENTS DESCRIPTION	CODE NUMBERS (SEE EXHIBIT B)
News worthy occurrences of questionable significance	1, (3 and 4 possibly)
Accidental ignition of gas	1 (13 possibly) (4 CKY only)
Civil disturbances	1
Damage to Company and/or other property in excess of $50,000	1, 3, 4 and 9 (7 if Company property)
Damage to Company and/or other property in excess of $25,000 (CKY only)	1, 4, either or both 7 & 9
Death of a Company Employee-Work Related	1, 2, 5 and 6 (3 and 4 if gas related)
Gas related non-employee:	
Injury	1, 3, 4 and 9
Illness, such as carbon monoxide poisoning	1
Non-Gas related non-employee:	
Vehicle accident	11, 12 (16 & 17 possibly)
Injury	1 and 9
Non-Gas related property damage	8 and 9
Gas related employee:	
Injury (hospitalization)	1, 2, 3, 4, 5 and 6
Illness, such as carbon monoxide poisoning	1, 2, 5 and 6
Non-Gas related employee injury and illness:	
Restricted Duty	5 and 6
First Aid	5
Lost Time or 5 or more hospitalized	2, 5 and 6

EXHIBIT A
(2 OF 3)

ACCIDENT/INCIDENTS DESCRIPTION	CODE NUMBERS (SEE EXHIBIT B)
Damage to Company vehicle (including but not limited to cars, trucks, backhoes, compressors, welders or rental or personal vehicles authorized for use on Company business)	11 (12 possibly)
Company vehicle accident causing damage to others (third party)	9, 11, 12, and 17 (16 possibly)
Company vehicle accidents causing injuries, hospitalization and/or fatalities (third party)	2, 9, 11, 12, and 17 (16 possibly)
Evacuation of building or areas	1
Environmental Occurrences	1 (possibly 3 and 4)
Explosions	1 (13 usually and possibly 3, 4 and 9)
Floods affecting gas facilities	1 (possibly 3 and 4)
Gas related fires	1 (13 usually and possibly 3, 4 and 9)
Line breaks or facility failures of significant nature (rerouting gas loads, local curtailment, potential outage)	1, 10 and 13 (15 usually and possibly 3 and 4)
Low pressure over a wide area	1
Major power outage during heating season	1
Major segment of line taken out of service (unscheduled)	1 (4 CKY only if line operates at or about 20% SMYS and 10 and 16 usually)
Odor of gas over wide area	1, 13

EXHIBIT A
(3 OF 3)

ACCIDENT/INCIDENTS DESCRIPTION	CODE NUMBERS (SEE EXHIBIT B)
Outage of significant nature (considering number of customers, and duration)	1 and 4 (14 possibly)
Overpressuring of a system	1 (10 possibly)
Dig-ins	7, 13 (possibly 1,3 & 4)
Damage to Company facilities caused by others	7
Failures, such as: Collar or Coupling pullout Joint failure (weld, butt fusion, etc.) Flange, Valve, Regulator, etc. breakage Valve fails to function	10 (13 usually and possibly 1, 3 and 4)

**EXHIBIT B
(1 OF 2)**

Code No.	Description	Form No.	Gas Standard Ref. No.
1	Telephone Notification to General Office: Gas related incidents to: Engineering - Plant/Service Operations Section, as appropriate Non-gas related accidents/incidents involving Employees: Environmental, Health and Safety - Health and Safety Non-employees: Law - Claims Manager	refer to applicable gas standard	Emergency Manual, HSE 4000.010, HSE 4400.020(CG)
2	Telephone Notification to the Health and Safety Section	refer to applicable gas standard	HSE 4000.010
3	Department of Transportation Report	PHMSA F 7100.1 PHMSA F 7100.2	Emergency Manual
4	Report to State Utility Commission	refer to applicable gas standard	Emergency Manual
5	Occupational Injury/Illness Report	refer to applicable gas standard	HSE 4000.010
6	State Workers' Compensation Forms	n/a	HSE 4000.010
7	Damage to Company Facilities	GS 1100.030-2	GS 1100.030
8	Settlement of Minor Property Damage to Others Due to Construction and Maintenance	report to applicable supervisor	tbd
9	Property Damage and/or Personal Injury to Others	refer to applicable gas standard	GS 1150.007(CG)
10	Facility Failure	GS 1652.010-1	GS 1652.010
11	Vehicle Accident	refer to applicable gas standard	HSE 4300.020
12	State Vehicle Accident Report (if applicable	n/a	HSE 4300.020

**EXHIBIT B
(2 OF 2)**

Code No.	Description	Form No.	Gas Standard Ref. No.
13	(DPI) Leak Order	GS 1708.100-1	GS 1708.100(CG)
14	186 Work Order (or Job Order)	WMS generated	GS 2810.012(CG)
15	107 and/or 108 Work Order (or Job Order)	WMS generated	GS 2810.012(CG)
16	Vehicle Engaged in Interstate Operations Subject to DOT Motor Carrier Safety Regulations	refer to applicable federal website	tbd
17	Telephone Notification to the Insurance Section immediately following a motor fleet accident which causes a third party injury, fatality, or property damage in excess of $2,000	refer to applicable gas standard	HSE 4300.020

NiSource **Gas Standard**

Distribution Operations

Effective Date: 04/01/2010	**Response to a Line Break**	Standard Number: **GS 1150.020**
Supersedes: N/A		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when responding to line break situations.

Do not assume that the break you can see is the only break. It is still necessary to check adjacent buildings and buildings directly across the street since hazardous conditions may exist from other breaks that can not be seen.

Follow Company's damage prevention procedures, including One Call notification, if excavation is required.

Some line breaks may require reporting as a safety–related condition (refer to GS 1020.010). The person discovering a probable safety-related condition shall promptly notify the most appropriate front line leader/supervisor.

2. SPECIFIC ACTIONS

2.1 If escaping gas is an immediate danger to life and/or property:

a. Protect life, evacuate as appropriate.

b. Protect property.

c. Refer to GS 1714.010 "Leak Classification and Response" Table 1 for additional responses to a Grade 1 leak.

d. Notify supervision/dispatch center, as needed, of situation and confirm appropriate options for turning off gas.

e. Take the appropriate steps to control the flow of gas.

2.2 Secondary Damage Considerations

If the line break is due to natural forces or due to excavation activities where a gas facility has been damaged, consider the potential for secondary damage that may be allowing gas to escape from some other point than the known break site. Consideration should be given to, but not limited to the following:

a. Pullout of couplings

b. Cracked fittings

c. Cracked or broken weld

2.3 For leak investigation outside a building, follow Gas Standard GS 1708.070.

2.4 For leak investigation inside a building, follow Gas Standard GS 1708.060.

a. If the leakage is detected entering the building from an outside source, the investigation must immediately extend to the outside area around the building.

b. Continue to monitor area to assure that changing conditions do not cause a hazardous situation in addition to what was detected.

NiSource
Distribution Operations

Gas Standard

Effective Date: 08/01/2013	Response to an Explosion or Fire	Standard Number: GS 1150.030
Supersedes: 04/01/2010		Page 1 of 4

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR PART 192.615

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when responding to a fire or an explosion. It is recognized the circumstances of the moment will have an influence on what the employee may be able to do.

2. EXPLOSION - SPECIFIC RESPONSE BY THE EMPLOYEE WHEN THE EMPLOYEE IS ON THE PREMISES

2.1 Evaluate Conditions

Make a quick visual appraisal of the general conditions. The appraisal should include injuries to the employee, fellow employees, the public, extent of damage in the area, presence of fire, and the possibility of escaping gas.

If possible, mentally note the location of gas and electric control points. If safe to do so, turn off gas to any structure on fire or heavily damaged and note the time the gas was turned off. Contact the Integration Center and request immediate assistance.

2.2 Notify the Integration Center

Depending on the necessity of assisting injured occupants or of taking other immediate measures to minimize further damages or injuries, the employee should notify the Integration Center that additional assistance is needed (e.g., internal or external) as soon as possible. A follow-up call should again be made to the Integration Center upon completion of all necessary measures that have to be taken immediately. Integration Center personnel will inform appropriate management (e.g., Emergency Notification System) as appropriate, as soon as is practical.

2.3 Instruct Occupants

The employee should determine from his/her own physical condition what he/she is able to do. He/she may only be able to issue instructions. The employee should remember that he or she is the knowledgeable and authoritative person at the site.

The employee should check for the presence of occupants, including fellow employees as well as the public. Audible indications may help locate affected individuals.

The employee should instruct ambulatory occupants to evacuate to a safe area.

2.4 Ensure Public Safety

The primary concern is to keep people at a safe distance.

3. EXPLOSION - SPECIFIC RESPONSE BY AN EMPLOYEE UPON ARRIVAL AT THE PREMISES

3.1 Evaluate Conditions

Upon arrival at the scene, the employee should make a quick visual appraisal of the general scene. The primary points to initially cover are:

a. EXTENT OF DAMAGE - Determine approximate extent of damage – building completely demolished, windows blown out, one wall blown out, no apparent damage from the outside, etc.

b. PRESENCE OF FIRE - If possible, determine if fire has ignited escaping gas. If no fire exists, the presence of escaping gas should be assumed until tests prove otherwise.

c. APPARENT INJURIES - Look for affected individuals. Audible indications from inside structure may locate affected individuals.

d. GAS AND/OR ELECTRIC SERVICE - If Fire or Police Department personnel are present on the scene, they probably will have established a system of controls. Identify oneself as representing the gas Company and obtain their appraisal of the conditions of the gas and/or electric services. On the basis of what is learned from them and can be observed, advise them as to the best course of action in shutting off gas service. A mutual agreement should be reached before the employee proceeds.

3.2 Notify Integration Center

Inform Integration Center of conditions observed and what your next action will be. Integration Center personnel will inform appropriate management (e.g., Emergency Notification System) as appropriate, as soon as is practical.

Inform Integration Center that additional assistance is needed (e.g., internal or external) as soon as possible.

3.3 Instruct Occupants

a. ASSIST AS REQUESTED BY FIRE OR POLICE DEPARTMENTS.

b. IF POLICE OR FIRE DEPARTMENTS ARE NOT ON SITE - Employee is now the knowledgeable and authoritative person at the site. Check for presence of occupants. Audible indications from inside structure may locate affected individuals. Inspect area around structure for presence of affected individuals. Question those who are at scene; they may be occupants or neighbors. Try to establish an accounting for all who have been in the structure at the time of explosion. Conditions will dictate procedures to be followed in evacuating affected individuals. The employee may need help and his/her only source is from those people at the scene. Ask for volunteers, if needed. The employee will have to use his own judgment.

c. When police or fire department personnel arrive at the scene, verify that a request has been made for an ambulance, if needed.

3.4 Ensure Public Safety

The primary concern is to keep people at a safe distance.

4. STRUCTURE FIRE - SPECIFIC RESPONSE BY AN EMPLOYEE UPON ARRIVAL AT THE PREMISE

4.1 Evaluate Conditions

Upon arrival at the scene, the employee should make a quick visual appraisal of the general scene. The primary points to initially cover are:

a. EXTENT OF DAMAGE - Determine approximate extent of damage – building completely demolished, windows blown out, one wall blown out, no apparent damage from the outside, etc.

b. PRESENCE OF FIRE - If possible, determine if fire has ignited escaping gas. If no fire exists, the presence of escaping gas should be assumed until tests prove otherwise.

c. APPARENT INJURIES - Look for affected individuals. Audible indications from inside structure may locate affected individuals.

d. GAS AND/OR ELECTRIC SERVICE - If the Fire or Police are present on the scene, they probably will have established a system of controls. Identify oneself as representing the gas Company and obtain their appraisal of the conditions of the gas and/or electric services. On the basis of what is learned from them and can be observed, advise them as to the best course of action in shutting off gas or electric service. A mutual agreement should be reached before employee proceeds. If there is a fire and it has the potential to spread to other structures with gas service; turn off those services, if it is safe to do so.

4.2 Notify Integration Center

a. INFORM INTEGRATION CENTER OF CONDITIONS - Give a quick rundown on what has been observed in the evaluation.

b. INFORM INTEGRATION CENTER OF STATUS OF FIRE AND POLICE DEPARTMENTS - If fire and police are on the scene, inform the Integration center as to this fact. If they are not on the scene, inform the Integration Center of their absence. DO NOT WASTE TIME TRYING TO CONTACT THE POLICE OR FIRE DEPARTMENTS - let the Integration Center do that.

5. POST INCIDENT INVESTIGATION

If natural gas is involved, suspected or when deemed necessary by supervision, the following actions shall be performed.

a. Subsurface gas detection survey (i.e., bar hole tests). Document test (bar hole) locations, combustible gas indicator (CGI) readings and time CGI readings were taken. Refer to GS 1708.030 "Leakage Survey and Test Methods."

b. Odorant test (normally used after an explosion involving natural gas). Refer to GS 1670.020 "Odor Level Monitoring."

c. Additional leak survey(s) and/or test(s) as warranted by field conditions (e.g., pressure drop test, exposed piping test, gas detection survey, etc.). Refer to GS 1708.030 "Leakage Survey and Test Methods."

6. DOCUMENTATION

Document actions taken (e.g., arrival time, make safe time, bar hole test locations, bar hole readings and times readings were taken).

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/01/2010	**Carbon Monoxide Investigation**	Standard Number: **GS 1150.040**
Supersedes: N/A		Page 1 of 3

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when conducting a carbon monoxide investigation.

When the Company responds to a CO investigation call and access can not be gained inside the building, the Company will contact local Emergency Services (e.g., fire or police department) to gain access to test the inside atmosphere for the presence of CO. In addition to calling Emergency Services, the Company should consider other available options to assist Emergency Services in gaining access (e.g., locksmith). Gaining access during the initial response to the CO investigation call is the best means of determining whether a potentially life-threatening condition exists.

2. CARBON MONOXIDE (CO) INVESTIGATION

The following actions shall be taken.

a. Turn on and "Zero" the CO instrument outside in known fresh air prior to beginning the investigation.

b. Sample at the entrance BEFORE entering an area and immediately upon entry into a building or enclosure with suspected ambient CO levels.

    1. Continue to test the "free air" throughout the building at head height (or eye level). Unlike natural gas, CO is only slightly lighter than air (specific gravity .97) and minimal circulation will keep it diffused throughout the room.

       Make checks near heat ducts and registers, in basements and utility rooms, and near appliances that utilize combustible fuels.

    2. If a fireplace(s) is present, check around the opening for CO due to back drafting.

    3. If garage is attached, check CO levels in the garage.

c. Do not insert the probe into the combustion chamber or draft hoods of equipment. The hot flue-gases will damage the instrument.

d. Be sure to have all equipment that was in operation prior to your arrival put back in operation such as exhaust fans, dryers and whole house fans. These units have the capability of creating a back draft. Make sure all doors and windows are in the same position as when the condition was first noticed.

e. Take appropriate action in accordance with Table 1.

f. If occupants are disoriented or unconscious:

1. immediately notify the Company's dispatch center[1] that emergency medical assistance and a supervisor are needed,
2. monitor CO levels and protect yourself in accordance with the limits in Table 1, and
3. ventilate the building and/or move the victims to fresh air if the CO levels permit you to do this safely.

[1] Depending on the Company, the dispatch center refers to either the Work Management Center (Indiana) or the Integration Center.

Table 1

Response to Measured Levels of CO

CO Level in Ambient Air	Response
Any amount in the ambient air from a vented gas appliance	• Shut off and red-tag appliance (or correct problem)
Less than or equal to 10 ppm in a residence	• If vented gas appliances are eliminated as the source of the CO, this level will be considered within normal limits, i.e., “Acceptable” level in a residence
Less than or equal to 35 ppm in a commercial building	• If vented gas appliances are eliminated as the source of the CO, this level will be considered within normal limits, i.e., “Acceptable” level in a business
Above the “Acceptable” level but less than 100 ppm	• Notify customer or building manager • Continue with CO investigation
Readings of 100 ppm to 200 ppm	• Minimize time spent in the building (maximum of 15 minutes) until levels are reduced • Call for assistance if there is any question that help may be needed • Shut off gas at the meter, curb or at the equipment (if equipment can be accessed safely and quickly) • Turn thermostats “off” as you pass them • Ventilate building • Evacuate building unless CO levels drop immediately to less than 100 ppm • Continue investigation when levels drop to below 100 ppm
Readings above 201 ppm	• Do not stay inside the building for any reason • Attempt to notify occupants to evacuate only while you are exiting the building • Contact the Company’s dispatch center and request assistance. Supervisor should be notified. Request Fire Department (emergency responders), if needed • Shut off gas outside at the meter or curb valve, if possible • Evacuate the building – DO NOT re-enter until levels are below 200 ppm • Ventilate Building – DO NOT re-enter until levels are below 200 ppm • Continue investigation when levels drop below 100 ppm

Distribution Operations

Gas Standard

Effective Date: 04/01/2010	Gas Odor Investigation	Standard Number: **GS 1150.050**
Supersedes: N/A		Page 1 of 1

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when conducting a gas odor investigation.

2. SPECIFIC ACTIONS

2.1 For leak investigation outside a building, follow GS 1708.070, "Outside Leak Investigation."

2.2 For leak investigation inside a building, follow GS 1708.060, "Inside Leak Investigation."

2.3 Gas Odor Over Large Area

Begin by responding to area indicated by service call(s). During investigation consider the following:

a. Odor may be result of natural gas release or leak
b. Odor may be result of propane release or leak
c. Odor may be result of odorant release or leak

Follow leak investigation procedures in section 2.1, 2.2, or 2.4.

Notify Supervision/dispatch when the source of the odor is found.

If it is determined that natural gas or propane are not the source of odor, inform supervision/dispatch center so that the appropriate local authorities may be notified.

2.4 If propane gas is suspected to be the cause of the odor, follow GS 1708.050, "Propane Systems Leakage Survey and Test Methods."

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2012	**Response to Natural Disasters**	Standard Number: **GS 1150.060**
Supersedes: 04/01/2010		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property. The number one priority is to protect life, including one's own life.

In addition to the steps outlined in the GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when responding to natural disasters.

When a natural disaster that affects the gas distribution system occurs, the LDC's dispatch center shall immediately dispatch employees to the affected area to analyze the situation and report their findings. Measures appropriate to the conditions will be taken to eliminate existing or potential hazards.

When responding to a natural disaster outside your normal operating area it is advisable that you fuel all vehicles and equipment prior to leaving for the disaster site, as fuel may not be readily available in the disaster site or areas located within close proximity to the site.

Have and use appropriate PPE at all times. (GS 1150.010 Section 1)

Be aware of debris that could fall from above when working around buildings and facilities damaged by the storm(s).

Make sure that the Integration Center knows where you are at all times.

Watch out for debris on the road surface that could contain nails, screws and other objects that may puncture a tire rendering you stranded without transportation.

Watch for hazards such as downed, but energized power lines.

Use caution when traveling in restricted areas that have been shut down by Emergency Services.

Immediately secure M&R settings after a loss of a regulator building to discourage tampering.

2. SPECIFIC ACTIONS

In preparation for a natural disaster, act as directed by supervision.

2.1 If flooding has occurred, turn off affected customers by either meter or mainline valves, as directed.

a. Check all district regulators in affected areas to ensure vents and relief stacks are above flood level.

b. If possible, mark all above ground facilities that have become submerged and are in danger of being struck by vessels or debris.

c. View water crossings to determine if flooding has exposed or undermined pipelines. Pay particular attention to gas piping attached to bridges.

d. Keep supervision informed of findings.

2.2 If the flood results in an outage, notify supervision and the LDC's dispatch center and refer them to local Emergency Manual.

2.3 If high winds are associated with a Hurricane or Tornado

a. Check water bath heaters.

b. Check exposed facilities.

c. Watch for hazards such as downed power lines or structures that may have become unstable during the storm.

d. Use caution when traveling in restricted areas which have been shut down by Emergency services.

e. Remain alert and watchful for an additional wave of severe weather and seek shelter accordingly.

2.4 In response to an Earthquake

Conduct leak surveys of certain below ground facilities as directed by supervision and/or the LDC's dispatch center. Conduct patrolling and visual inspection of certain aboveground facilities (e.g., regulator stations, LNG plants, LPG plants and certain aboveground gas mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage as directed by supervision and/or the LDC's dispatch center.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/22/2013	**Response to Low or No Pressure**	Standard Number: **GS 1150.070**
Supersedes: 04/01/2010		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, “Emergency Response – General Guidelines” the specific actions below should also be considered when responding to low or no pressure problems

2. SPECIFIC ACTIONS IN RESPONSE TO LOW OR NO PRESSURE CALLS FROM CUSTOMERS

1. Before beginning the investigation into the cause of the pressure problem, secure as much information as possible from the dispatch center, the call center or the job work order such as: the name of the person reporting the problem, telephone number, address or location, pressure conditions and how long the condition has been evident. Low or no pressure can be caused by several things (e.g., a failed regulator, a line break, debris or water in the main or service, etc.).

2. If the problem is in the meter set, the serviceperson should correct the problem. (Corrections to customer piping beyond the meter set are made in accordance with procedures established in the Company’s service standards.).

3. If the problem is in the service line, the serviceperson should shut off the meter and check a neighboring residence fed from the same distribution segment to determine if a general distribution pressure loss has occurred.

   NOTE: Refer to GS 1012.010 “Definitions” for guidance regarding **normal operating pressure** ranges.

4. If the serviceperson determines that the problem is in the single service line, he/she should notify the dispatch center so that a crew can be dispatched to resolve the problem with the service line.

5. If the serviceperson determines that several service lines are involved indicating loss of pressure in a substantial part of the distribution system, he/she should notify the dispatch center immediately. Notify the dispatch center of pressure readings obtained and the addresses that have been checked. At the same time, the Company may begin to receive calls from many customers. Work with the dispatch center to determine the extent of the low or no pressure problem by the

location of service call(s) and canvass other customers in the immediate area as directed by supervision.

6. If subsequent information reveals the gas pressure to appliance burners is 2.5 inches water column or less and is found at a sufficient number of premises to indicate that a general area outage has occurred or is occurring, the Company shall take action to isolate the system.

7. In response to isolating the system, servicepersons as directed by supervision, will participate in the Company's Outage Management Plan. Field personnel should begin to systematically shut off potentially affected gas services. If it is necessary to enter a customer's premise to which access cannot be gained, the Company will contact local Emergency Services (e.g., fire or police department) to gain access.

3. SPECIFIC ACTIONS IN RESPONSE TO PRESSURE ALARMS RECEIVED AT GAS SYSTEMS CONTROL

When a pressure alarm is received at Gas Control from telemetry monitoring a propane plant, an LNG plant, a gate station or a pressure regulating station, Gas Control will dispatch the proper Gas Systems Operations personnel to the site to investigate and correct the problem.

Distribution Operations

Gas Standard

Effective Date: 04/22/2013	Response to Over Pressure	Standard Number: GS 1150.080
Supersedes: 04/01/2010		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, “Emergency Response – General Guidelines” the specific actions below should also be considered when responding to over pressure problems.

2. SPECIFIC ACTIONS IN RESPONSE TO OVER PRESSURE CALLS FROM CUSTOMERS

1. Before beginning the investigation into the cause of the pressure problem, secure as much information as possible from the dispatch center, the call center or the job work order such as: the name of the person reporting the problem, telephone number, address or location, the normal and maximum allowable operating pressure of the distribution system feeding the service line, pressure conditions and how long the condition has been evident. Over pressure can be caused by several things (e.g., a failed customer appliance regulator, a failed meter set regulator, a failed regulator station regulator, etc.).

2. Upon arrival at the location, the service person should determine whether the location is served by a low pressure or higher pressure distribution system. A low pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided the customer. A higher pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

3. If the meter set has a service regulator, check the regulator outlet pressure (i.e., delivery pressure to the customer). If the service regulator is found to exhibit normal outlet pressure at the meter set, the problem may be attributable to a failed customer appliance or customer equipment regulator. In this case, shut off the gas to the customer and red tag the customer’s equipment. Advise the customer of the steps he or she needs to take and options available to him/her before the company can re-establish gas service to the premises. (Corrections to customer piping beyond the meter set are made in accordance with procedures established in the LDC’s service standards.). Notify the dispatch center of conditions found and actions taken.

4. If the service regulator is found to exhibit abnormal pressure at the meter set, and the inlet pressure to the regulator is found to be within normal distribution system operating parameters (refer to GS 1012.010 “Definitions” for the definition of **normal operating pressure**), repair or replace the regulator/fit, as appropriate, to establish normal delivery pressure again. Before resuming service to the customer, ascertain whether the abnormal pressure found upon arrival was detrimental to the customer’s appliance or equipment regulators. (Corrections to customer piping beyond the meter set are made in accordance with procedures established in the service standards.). Notify the dispatch center of the problem found and the actions taken to resolve the problem.

5. If the distribution system pressure is found to exceed normal system operating parameters or exceeds the maximum allowable operating pressure (refer to GS 1012.010 “Definitions” for the definition of **normal operating pressure**), notify the dispatch center immediately. Instruct the dispatch center to notify your supervisor, Gas Systems Operations and Gas Control that the distribution system has excessive pressure. Continue to survey additional locations to determine the extent of the over pressurization. If additional over pressurization conditions are found, take actions to make the situation safe (e.g., turn off gas, evacuate building, etc.). Notify the dispatch center of the actions taken.

6. Before resuming service to a customer, ascertain whether the abnormal inlet pressure found upon arrival was harmful to the company’s or customer’s equipment. Repair or replace the regulator/fit, if damaged or exposed to inlet pressures which exceed the maximum allowable emergency inlet pressure prior to reestablishing service. (Corrections to customer piping beyond the meter set are made in accordance with procedures established in the service standards.). Notify the dispatch center of the actions taken to resolve the problem.

3. SPECIFIC ACTIONS IN RESPONSE TO PRESSURE ALARMS RECEIVED AT GAS SYSTEMS CONTROL

When a pressure alarm is received at Gas Control from telemetry monitoring a propane plant, an LNG plant, a gate station or a pressure regulating station, Gas Control will dispatch the proper Gas Systems Operations personnel to the site to investigate and correct the problem.

4. SPECIFIC ACTION IF DISTRIBUTION SYSTEM MAOP IS EXCEEDED

If the over pressurization resulted in exceeding the MAOP of the distribution system, consideration should be given to conducting leak surveys over the portion of the distribution system that experienced the over pressurization.

Distribution Operations

Gas Standard

Effective Date: 04/01/2010	**Response to Civil Disturbances**	Standard Number: **GS 1150.090**
Supersedes: N/A		Page 1 of 1

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property.

In addition to the steps outlined in the Gas Standard GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when responding to gas emergency calls in an environment of civil disturbance.

If the need arises or situation warrants, refer to the Company's gas standard on Response to Security Threats and Breaches.

2. SPECIFIC ACTIONS

If there is a known civil disturbance, respond only to emergency calls in the identified area of disturbance unless instructed otherwise by supervision or the dispatch center. Depending upon the magnitude of the situation, response may not be possible. Do not jeopardize your own personnel safety if a situation could result in a hostile confrontation. Communicate with supervision for operational instructions throughout the duration of the civil disturbance.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/01/2010	**Response to Security Threats and Breaches**	Standard Number: **GS 1150.100**
Supersedes: N/A		Page 1 of 4

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

The primary role, as a first responder, is to make the situation safe in order to prevent injury to persons or damage to property. Do not jeopardize your personal safety if a situation could result in a hostile confrontation.

In addition to the steps outlined in the Gas Standard GS 1150.010, "Emergency Response – General Guidelines" the specific actions below should also be considered when responding to security threats and breaches. Corporate Security can be contacted at (866) 218-0530 (24 hours a day / 7 days a week) if any assistance is needed or to answer any security related questions.

2. SPECIFIC ACTIONS IN RESPONSE TO SECURITY THREATS AND BREACHES

2.1 The following shall trigger the Security Response Procedure. While these triggers represent conditions that are worth reporting, this list is not intended to be all-inclusive. Many other conditions exist that would be considered worth reporting. Those conditions must be considered on a case-by-case basis.

a. Suspicious vehicle(s) or individual(s) in or in close proximity to Company personnel or facilities.

b. Threats to Company personnel or facilities via direct contact, phone, letter, fax or third party.

c. Suspicious package(s) or items in or in close proximity to Company personnel or facilities.

d. Unexplained equipment operation disrupting or having the possibility of disrupting service to internal facilities and/or customers.

e. Normally locked security gates open and unattended at Company facilities.

2.2 If you have any reason to suspect a threat to your safety, you should move to a secure area and immediately call local authorities (911, if available) and await response of local law enforcement. Also, notify your supervisor/leader.

2.3 If a security response indicator is identified, immediately notify your supervisor and the dispatch center. It is highly likely local law enforcement will pull other agencies and/or resources into an incident of this nature. If you become aware of this type of involvement, relay this information to your supervisor and the dispatch center who will contact the LDC Security Manager and/or Corporate

Security. Corporate Security can be contacted at (866) 218-0530 (24 hours a day / 7 days a week) if any assistance is needed or to answer any security related questions.

2.4 All efforts should be taken to secure the incident scene.

a. Ensure unauthorized personnel do not enter the incident area or tamper with facilities or equipment.

b. Cooperate fully with all law enforcement personnel already at the scene. One of the first things law enforcement will do is establish a secured perimeter. It is important that you have proper company credentials to identify yourself to law enforcement authorities to ensure access to our facilities.

c. Ask, as appropriate, for credentials of responding emergency personnel.

2.5 Take steps necessary to prevent loss of life and restore critical service and be mindful of the need to preserve any/all potential evidence. Every effort should be taken not to disturb potential evidence. Our facility could become subject to a crime scene investigation by local or federal authorities.

3. BOMB THREAT GUIDELINES

3.1 It has been proven that a large majority of bomb threats are false alarms, meant only to disturb or disrupt the normal work of a person or company. HOWEVER, AT NO TIME SHOULD ANY CALL BE REGARDED AS JUST ANOTHER FALSE ALARM. When a call is received, there are several things to do.

a. Keep calm and courteous.

b. Keep the caller on the line as long as possible. Ask the caller to repeat the message.

c. Do not transfer or put caller on hold.

d. Retrieve phone number from caller ID, if available.

e. Record phone call, if possible.

f. Note caller characteristics. (e.g., male/female, accent, speech impediment).

g. Document exact wording of threat.

h. Obtain as much information from the caller as possible and speak slowly and ask the following questions, if possible:

1. When is the bomb going to explode?
2. Where is the bomb right now?
3. What kind of bomb is it?

4. What does it look like?
5. Why did you place the bomb?
6. What is your name and address?

i. Tell the caller the building is occupied and it might cause the death of some innocent people.

j. Listen for background noises that might help in determining where the call was made.

k. At the conclusion of the call, immediately report the call to your supervisor and/or dispatch center providing as much information as possible.

3.2 If determined that there is imminent danger, move or evacuate personnel immediately.

3.3 If the call is received within the local operating area or dispatch center, notify local authorities (911, if appropriate) in the impacted area.

3.4 If a suspected bomb is discovered, the following safety precautions should be taken very seriously.

DO NOT:

a. Use radio equipment or cell phones to transmit messages.
b. Operate light switches.
c. Smoke.
d. Accept the contents of any container as bona fide, simply because it was delivered by routing means.
e. Accept container markings and/or appearance as sole evidence of the content's identification and legitimacy.
f. Touch a suspected bomb.
g. Shake, shock or jar a suspected bomb.
h. Cover a suspected bomb.
i. Carry a suspected bomb.
j. Assume that a suspected bomb is of a specific (high explosive or incendiary) type.
k. Open any suspicious container or object.
l. Cut a string, cord, or wire on a suspicious container or object.
m. Cut or remove the wrapper on a suspicious container.
n. Unscrew the cover of a suspicious container or object.

o. Move the latch or hook on the cover of a suspicious container or object.

p. Raise or remove the cover of a suspicious container.

q. Change the position of a suspicious container or bottle.

r. Place a suspicious container or object in water.

NiSource

Gas Standard

Distribution Operations

Effective Date: 05/07/1990	**Communication with Fire, Police and Other Public Officials**	Standard Number: **GS 1150.200(CG)** P&P 511-2
Supersedes: N/A		Page 1 of 3

Companies Affected:

☐ NIPSCO	☑ CGV	☐ CMD
☐ NIFL	☑ CKY	☑ COH
☐ Kokomo Gas	☐ CMA	☐ CPA

REFERENCE Code of Federal Regulations - Title 49 - Part 192 - § 192.615

1. GENERAL

Each Operating Area shall establish and maintain liaison with appropriate fire, police and other public officials to:

a. learn the responsibility and resources of each government organization that may respond to a gas emergency;

b. acquaint the officials with the Company's capability in responding to a gas emergency;

c. identify the types of gas emergencies for which the Company notifies the officials and those that public officials should notify the Company;

d. plan how the Company and public officials can engage in mutual assistance to minimize hazards to life or property; and

e. review with public officials names of other operators in the area, if appropriate.

Each operating area shall establish and maintain, in the appropriate section of the Emergency Manual, a list of current government officials.

2. DOCUMENTATION

Each contact with fire, police and other public officials for the purpose of emergency planning shall be documented. Documentation should include the date, name of employee making the contact, persons contacted and purpose of contact. See Exhibit B for suggested format.

Annually, each operating area shall provide the District Manager with a contact summary. The summary shall reflect the purpose of the contact.

Gas Standard

Distribution Operations

Effective Date: 05/07/1990	**Communication with Fire, Police and Other Public Officials**	Standard Number: **GS 1150.200(CG)** P&P 511-2
Supersedes: N/A		Page 2 of 3

EXHIBIT A

Note: This is an example of the type of form to be filled out for each town.

PERSON-IN-CHARGE

ADDRESS LISTING

MAYOR

Name	Home Phone	Office Phone

CITY MANAGER (If Applicable)

Name	Home Phone	Office Phone

CHIEF OF POLICE

Name	Home Phone	Office Phone

FIRE CHIEF

Name	Home Phone	Office Phone

THOSE CUSTOMERS WHO SHOULD RECEIVE SPECIAL ATTENTION

HOSPITAL(S)	Name	Address
	Name	Address
NURSING HOMES	Name	Address
	Name	Address

POSSIBLE REMOTE OPERATING CENTERS

	Name	Address/Name of Contact Person
LOCKSMITH	Name	Address

1-1-87 A2

ENG:SO-0001

Effective Date: 05/07/1990	Communication with Fire, Police and Other Public Officials	Standard Number: **GS 1150.200(CG)** P&P 511-2
Supersedes: N/A		Page 3 of 3

EXHIBIT B

Community: Bellville, Ohio

Purpose	Date	By Title	Name
Contact: Fire Department Chief (A. Arson)			
Natural gas fire fighting training	5/13/89	Plt. Supv.	F. Jones
Properties of gas demonstration	6/25/89	Safety Advisor	J. Cook
Tour of Company facilities	6/25/89	Area Manager	W. Wilcox
Demonstration of Company dispatching facilities	8/04/89	Ser. Supv.	R. Brown
Tour of Fire Dept. facilities and equipment	10/10/89	Plt/Serv. Supv.	Jones/Brown
Evacuation	7/15/89	Plt/Serv. Supv.	Jones/Brown
Contact: Chief of Police (Joe Copper)			
Properties of gas demonstration	6/25/89	Safety Advisor	J. Cook
Evacuation Procedures	7/15/89	Plt/Ser. Supv.	Jones/Brown
Contact: Emergency Response Coordinator (I. A. Ware)			
Properties of gas demonstration	6/25/89	Safety Advisor	J. Cook
Evacuation	7/15/89	Plt/Ser. Supv.	Jones/Brown
List of other operators	7/15/89	Plt/Ser. Supv.	Jones/Brown

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Gas Control Room Management	Standard Number: **GS 1170.010**
Supersedes: 01/01/2013		Page 1 of 5

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.631

1. GENERAL

The purpose of this procedure is to identify the specific requirements for the Company's Control Room operations.

Procedures for employees to follow in regards to gas control operations are found in the Company's written "Control Room Management Plan" and applicable policies and procedures.

2. ROLES AND RESPONSIBILITIES

The Company has defined the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions (see Exhibit D of the "Control Room Management Plan"). To ensure a controller's prompt and appropriate response to operating conditions, the Company has defined each of the following in the "Control Room Management Plan" and applicable policies and procedures.

a. A controller's authority and responsibility to make decisions and take actions during normal operations.

b. A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others.

c. A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others.

d. A method of recording controller shift-changes and any hand-over of responsibility between controllers.

3. ADEQUATE CONTROL ROOM INFORMATION

Section 5 of the Company's "Control Room Management Plan" provides guidance to controllers with the information, tools, processes and procedures necessary for the controllers to carry out their roles and responsibilities.

3.1 API RP 1165 Pipeline SCADA Displays

Where applicable the Company will implement Sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 whenever a SCADA system is added, expanded or replaced. Where certain provisions of the API sections are not practical the Company shall list the justification. See the Supply & Optimization policy and procedure “SCADA Standards API RP 1165” for additional guidance.

3.2 Point-to-Point Verification

The Company shall conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays. In addition to Section 5.3 of the “Control Room Management Plan,” see the Supply & Optimization policy and procedure “Point Point-to-Point Verification” for additional guidance.

3.3 Internal Communication Plan

The Company shall test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months. See Section 5.4 of the “Control Room Management Plan” and the Supply & Optimization policy and procedure “Internal Communication Plan” for additional guidance.

3.4 Testing Backup SCADA Systems

The Company shall test its backup SCADA systems at least once each calendar year but at intervals not to exceed 15 months. See Section 5.5 of the “Control Room Management Plan” and the Supply & Optimization policy and procedure “Backup SCADA System Test” for additional guidance.

3.5 Controller Shift Changes

The Company has established procedures for when a different controller assumes responsibility, including the content of information to be exchanged. Refer to Sections 4.2, 4.3 and 4.4 of the “Control Room Management Plan” and the Supply & Optimization policy and procedure “Shift Turnover” for additional guidance.

4. FATIGUE MANAGEMENT

The Company shall implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities.

a. Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep. See Section 6.1 of the

"Control Room Management Plan" and the Supply & Optimization policy and procedure "Fatigue Mitigation" for additional guidance.

b. Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue. See Section 6.2 of the "Control Room Management Plan" for additional guidance.

c. Train controllers and supervisors to recognize the effects of fatigue. See Section 6.2 of the "Control Room Management Plan" and the Supply & Optimization policy and procedure "Fatigue Mitigation" for additional guidance.

d. Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility. See Section 6.1 of the "Control Room Management Plan" and the Supply & Optimization policy and procedure "Fatigue Mitigation" for additional guidance.

5. ALARM MANAGEMENT

The Company's written alarm management plan is provided in Section 7 of the "Control Room Management Plan." The purpose of the alarm management plan is to provide for effective controller response to alarms and includes the following requirements.

a. Review of SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations.

b. Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities.

c. Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year but at intervals not to exceed 15 months.

d. Review the alarm management plan at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan.

e. Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, to determine that controllers have sufficient time to analyze and react to incoming alarms.

f. Address deficiencies identified through the implementation of the Company's alarm management plan.

6. CHANGE MANAGEMENT

Changes that could affect control room operations shall be coordinated with control room personnel. Section 8 of the Company's "Control Room Management Plan" provides requirements for the following.

a. Communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration.

b. Contacting control room personnel when emergency conditions exist and when making field changes that affect control room operations. Contact should be made in a manner suitable for the condition at hand. Examples include communicating via cell/telephone, MDT messaging, Integration/Logistics/WM Center.

c. Control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

7. OPERATING EXPERIENCE

The Company shall incorporate lessons learned, as appropriate, from its operating experience into its control room management procedures in accordance with the following.

a. Reviewing incidents as defined by GS 1020.020 “Incident Reporting” to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to the following.

   1. Controller fatigue.
   2. Field equipment.
   3. The operation of any relief device.
   4. Procedures.
   5. SCADA system configuration.
   6. SCADA system performance.

b. Updating the Company’s training program for control room operations.

8. TRAINING

The Company shall maintain a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. The Company shall train each controller to carry out the roles and responsibilities.

The Company’s training program for controllers shall include the following elements.

a. Responding to abnormal operating conditions likely to occur simultaneously or in sequence.

b. Use of a computerized simulator or non-computerized (tabletop) method to recognize abnormal operating conditions.

c. Responsibilities for communication under the operator's emergency response procedures.

d. Working knowledge of the pipeline system, especially during the development of abnormal operating conditions.

e. For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

9. COMPLIANCE VALIDATION

Upon request, the Company shall submit its procedures to the appropriate State agency.

10. COMPLIANCE AND DEVIATIONS

The Company shall maintain for review during inspection the following.

a. Records that demonstrate compliance with the requirements of this standard.

b. Documentation to demonstrate that any deviation from the procedures required by 49 CFR Part 192.631 was necessary for the safe operation of a pipeline facility.

Distribution Operations

Gas Standard

Effective Date: 07/01/2014	**Nondestructive Testing**	Standard Number: **GS 1210.010**
Supersedes: 01/01/2013		Page 1 of 8

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192.241(b), 192.243

1. GENERAL

This standard covers the requirements for visual inspection and nondestructive testing (NDT) of welds made on Company pipeline facilities. Any weld determined to be unsatisfactory according to the inspection method used shall be repaired or replaced. The acceptability of a weld that is nondestructively tested or visually inspected shall be determined according to the standards in the current PHMSA incorporated by reference edition of API 1104. The current acceptance criteria are located in Exhibit A.

The nondestructive testing contractor or Company shall have and follow written procedures for testing and for the proper interpretation of each nondestructive test. The individual performing the test must be trained and qualified in the established testing procedures and with the equipment employed in testing.

All non-destructive testing shall be performed on an uncoated weld.

2. VISUAL INSPECTION

All completed welds shall be visually inspected by a person who has been trained and qualified in established visual inspection procedures. Each weld inspected shall be free from cracks, inadequate penetration, and burn-through; and must present a neat workman-like appearance. Refer to the current Welding Manual for complete procedures for qualifying personnel and performing visual inspection of welds.

3. NONDESTRUCTIVE TESTING METHODS

When nondestructive testing of welds is required according to Section 5 of this standard, one of the following methods shall be used:

a. Radiographic Inspection (x-ray) – this is the preferred method.

b. Ultrasonic Inspection - may be used in place of radiographic inspection as a primary inspection method only with prior approval of the Engineering Manager. Ultrasonic inspection is also useful in determining the exact depth of a radiographically located defect within a weld.

c. Magnetic Particle or Liquid Penetrant Inspection – to be used only when the primary inspection method, i.e. radiographic or, if approved, ultrasonics cannot be used on the weld configuration being tested, such as, certain fillet welds.

4. QUALIFICATION OF PERSONNEL

All personnel performing nondestructive testing shall be qualified in accordance with the American Society of Nondestructive Testing (ANST) "Recommended Practice No. SNT-TC-1A", latest edition. Only ANST certified levels II or III personnel shall be allowed to perform and interpret nondestructive tests.

All personnel using the radiographic testing method shall also follow all State regulations for radiation safety.

5. MINIMUM FEDERAL NONDESTRUCTIVE TESTING REQUIREMENTS

The minimum federal nondestructive testing requirements for pipeline welds are provided in Table 1. Refer to GS 2110.020 "Steel Pipe Design", Exhibit B, for percent specified minimum yield strength (SMYS) for all pipe sizes.

Welds nondestructively tested will be selected at random from the day's production and tested over their entire circumference. Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested when nondestructive testing is required per Table 1, row B.

Table 1 – Nondestructive Testing Requirements for Welds

	Pipeline Facility Description	Minimum Required Inspection
A	Designed to operate at less than 20% SMYS	Visual inspection of all welds
B	Designed to operate at greater than or equal to 20% SMYS	Visual inspection of all welds and ,nondestructive testing of at least the following percentages of each days field butt welds: • Class 1 locations – 10% of welds * • Class 2 locations – 15% of welds * • Class 3 & 4 locations – 100% of welds ** o At pipeline tie-ins, including replacement sections – 100% of welds o Within railroad rights-of-way – 100% o Within public highway rights-of-way including tunnels, bridges and overhead road crossings – 100 % of welds o At crossings of major or navigable rivers – 100%
	Exceptions	
C	Designed to operate at greater than or equal to 20% SMYS and pipe that has a nominal diameter less than 6 inches	Visual inspection of all welds
D	Designed to operate at greater than or equal to 20% SMYS but less than 40% SMYS and where the welds are so limited in number that non-destructive testing is impractical.	Visual inspection of all welds

* If the pipeline is being installed in a Class 1 or 2 location, consideration should be given to nondestructively testing 100% of the butt welds.

** Unless impractical, then at least 90% of the butt welds must be tested. Nondestructive testing must be impractical for each butt weld not tested.

Class locations are defined in GS 1012.010 “Definitions.”

6. RECORDS

When nondestructive testing is required in accordance with Table 1, row B, the Company must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of butt welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects. Welds shall be marked so as to unmistakably identify the weld with the appropriate radiographic film or ultrasonic test. The inspection contractor is responsible for submitting daily reports to the responsible Company representative. The reports shall include but are not limited to the following information for each weld that was tested.

a. welder identification,

b. identification of weld and areas of coverage,

c. location of weld,

d. work order or job number,

e. number of defects in each test,

f. acceptance or rejection, and

g. date.

Radiographic film is not required to be retained for the life of the pipeline. When retained, the radiography film shall be stored in a dry temperature controlled environment.

6.1 Recycling of Radiography Film

Radiography film is to be recycled. Contact Health, Safety & Environmental (HSE) or the NIPSCO Environmental Compliance Department for recycling of radiography film.

6.2 Radiography Film Disposal

Each operating area shall determine the length of time the film is be kept. Radiography film may contain silver and shall be handled as a hazardous waste when disposing the film. NiSource Gas Distribution Companies should refer to HSE 4400.040 “Hazardous Waste Management.” NIPSCO should contact the Environmental Compliance Department for guidance on disposal of radiography film.

**EXHIBIT A
(1 OF 4)**

Visual Examination Requirements		
Discontinuity	**Discontinuity**	**Discontinuity**
Cracks	None Permitted	None Permitted
Inadequate Penetration	None Permitted	None Permitted
Burn-Through	None Permitted	N/A
Weld Reinforcement (where the thinner component is 1/2" and under)	1/8" Maximum (1/16" desired)	N/A
Weld Reinforcement (where the thinner component is above 1/2")	3/16" maximum (1/16" desired)	N/A
Overlap	1/16" minimum - 1/8" maximum	N/A
Internal Concavity	Shall not reduce the total thickness of the joint, including reinforcement, to less than the thickness of the thinner component	N/A
Arc Strikes (Burns)	None Permitted	None Permitted
Low Cap/Cover	None Permitted	N/A
Internal Build-up	3/32" maximum	N/A
Porosity	None Permitted	None Permitted
Undercutting	**IF THE DEPTH IS:**	**LENGTH**
Butt Weld (EU & IU) Fillet Weld (EU Only)	Over 1/32" or over 12.5% of wall thickness	None Acceptable
	Over 1/64" or over 6% of wall thickness, but not over 1/32" or 12.5% of wall thickness	Total of IU plus EU shall not exceed 2" in any 12" length or 1/6 the weld length
	1/64" or less and 6% or less of wall thickness	EU is acceptable Consider only IU
NOTE: Welds must have a neat appearance		

NiSource
Distribution Operations

Gas Standard

Effective Date: 07/01/2014	Nondestructive Testing	Standard Number: **GS 1210.010**
Supersedes: 01/01/2013		Page 6 of 8

EXHIBIT A
(2 OF 4)

STANDARDS OF WELD ACCEPTABILITY

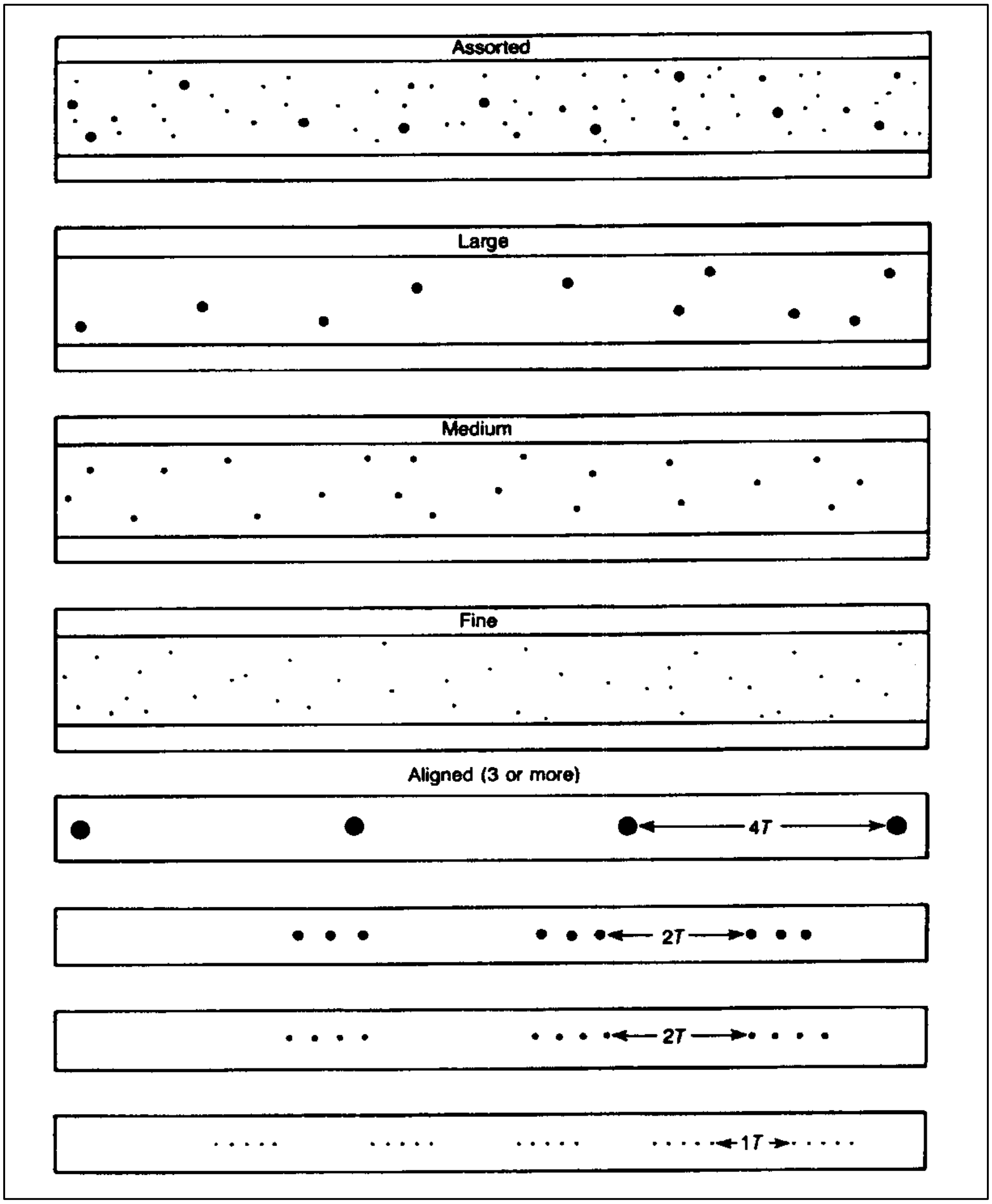
Non-destructive Testing Standards Of Acceptability For Welds In Pipelines And Mains
(Note: Acceptance standards comparable to API 1104, 20th Edition.)

Type Of Discontinuity	Abrv	Individual Size (1)	Total Length (1)	Special Under 2-3/8" O.D.(1)
Inadequate Penetration without high-low	IP	Shall not exceed 1" or 8% of weld length.	Total length shall not exceed 1" in 12", or 8% of weld length.	
Inadequate Penetration Due To High-Low	IPD	Shall not exceed 2" or 16% of weld length.	Total length shall not exceed 3" in 12", or 16% of weld length.	
Incomplete Fusion	IF	Shall not exceed 1" or 8% of weld length.	Total length shall not exceed 1" in 12", or 8% of weld length.	
Incomplete Fusion Due To Cold Lap	IFD	Shall not exceed 2" or 8% of weld length.	Total length shall not exceed 2" in 12", or 8% of weld length.	
Internal Concavity	IC	Any length, as long as the radiographic image of the "IC" is lighter than that of the thinnest adjacent base metal. If darker than that of the thinnest adjacent base metal, the dimensions of the IC shall not exceed that specified for burn-through.		
Burn-Through Considered "BT" only if the radiographic image is darker than that of the thinnest adjacent base metal.	BT	Shall not exceed 1/4" or t in any dimension. (2)	Total of the maximum dimensions of separate BT's shall not exceed 1/2" in any 12", or 1/2" if the total weld length is less than 12"	Only one BT is allowed, which shall not exceed 1/4" or t in any dimension. (2)
Elongated Slag Inclusion (Continuous, broken or parallel): Parallel "ESI" (wagon tracks) shall be considered as separate ESI's if the width of either one exceeds 1/32". (3)	ESI	Length shall not exceed 2" or 8% of weld length. Width shall not exceed 1/16". (If width exceeds 1/16", acceptance standards for ISI may apply.)	Total length of ESI plus ISI shall not exceed 2" in 12", or 8% of weld length.	Length shall not exceed 3t or 8% of weld length. (2) Width shall not exceed 1/16". Total length of ESI plus ISI shall not exceed 8% of the weld length.
Isolated Slag Inclusion (Irregularly shaped) (3)n	ISI	Length shall not exceed 1/2" or 8% of weld length. (If longer, acceptance standards for ESI may apply.) Width shall not exceed 1/8".	Total length of "ISI" shall not exceed 1/2" in 12", or 8% of weld length. Total length of ESI plus ISI shall not exceed 2" in 12", or 8% of weld length.	Length shall not exceed 2t or 8% of weld length. (2) Width shall not exceed 1/2t. (2) Total length of ESI plus ISI shall not exceed 8% of the weld length.
Porosity (individual or scattered)	P	Maximum dimension shall not exceed 1/8" or 1/4t. (2) Maximum distribution shall not exceed concentration shown in Exhibit 3 or 4		
Cluster Porosity (Finish pass only); "CP" in other passes shall comply with P requirements.	CP	Cluster diameter shall not exceed 1/2", with the maximum dimension of any individual pore within the cluster not to exceed 1/16".	Total combined length of clusters shall not exceed 1/2" in 12", or 8% of weld length.	
Hollow Bead	HB	Shall not exceed 1/2" or 8% of weld length.	Total length shall not exceed 2" in 12", or 8% of weld length. Individual HB's which exceed 1/4" in length shall be separated by at least 2".	
Crack	C	None, regardless of size or location, except crater cracks less than 5/32" in length.		
External Undercutting **Internal Undercutting**	EU IU	Total length of "EU" plus "IU" shall not exceed 2"in 12", or 1/6 of the weld length. If the undercutting can be mechanically measured, special acceptance criteria found in Exhibit 1 may be applied.		
Accumulation Of Discontinuities	AD	N/A	Excluding IPD, EU, and IU, total length shall not exceed 2" in 12", or 8% of weld length.	
Arc Strike (Arc Burn)	AS	None allowed. Welding Inspector must be consulted for disposition.		
Low Cap	LC	If indicated radiographically, image shall not exceed 1/4" or t in any dimension. (2)		

NOTES:
(1) If more than one acceptance standard is given for a discontinuity, the most restrictive shall apply.
(2) "t" is the thinner of the nominal wall thicknesses joined.
(3) When the size is measured, the indication's maximum dimension shall be considered its length.

EXHIBIT A
(3 OF 4)

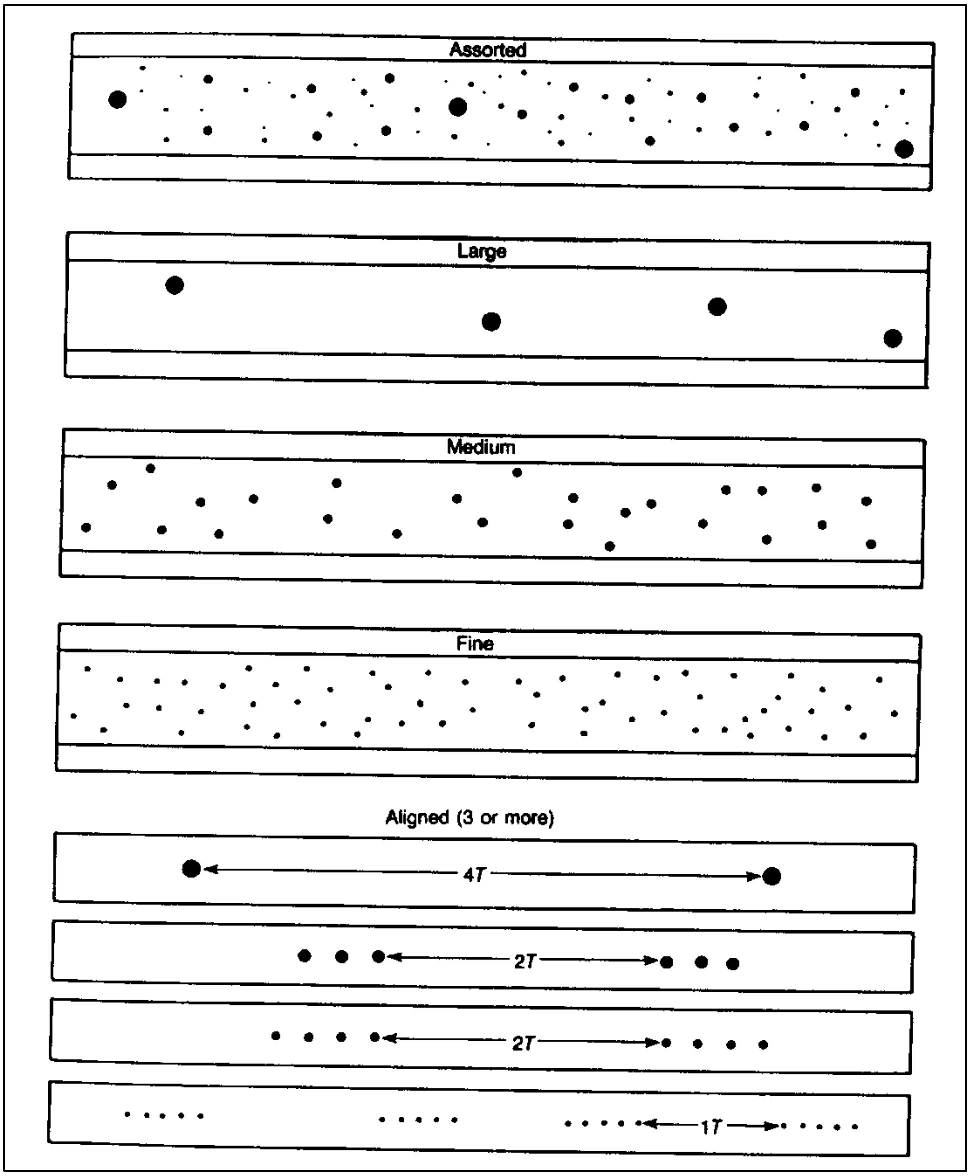
Maximum Distribution of Porosity: Wall Thickness 1/2" or Less



NOTE: The size of the porosity is not drawn to scale.

EXHIBIT A
(4 OF 4)

Maximum Distribution of Porosity: Wall Thickness Over 1/2"



NOTE: The size of the porosity is not drawn to scale.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Plastic Pipe Fusion and Mechanical Joining Qualification of Personnel	Standard Number: **GS 1301.010**
Supersedes: 07/01/2014		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.285, 192.287

1. TRAINING AND QUALIFICATION

A training program provides initial and remedial training for plastic joining techniques. Upon completion, a person is qualified to join plastic using one or more of the following procedures, socket fusion, butt fusion, electrofusion or mechanical fittings, and to evaluate the acceptability of joints made. The training program includes:

a. instruction lead by a qualified instructor,

b. successfully completing one joint for each procedure used in the field,

c. proper method to visually inspect a joint, and

d. in the case of heat fusion and electrofusion joints, destructive testing in accordance with Section 4.

2. RE-QUALIFICATION

All persons responsible for making plastic joints (i.e., fusion or mechanical) are required to re-qualify once each calendar year, not to exceed 15 months, or after any production joint fails as a result of pressure testing (as required by the applicable GS 1500.010 “Pressure Testing”) and that failure is due to incorrect construction/operation, before that individual can perform another plastic production joint in the field.

To re-qualify, each person must successfully complete steps b, c and d in Section 1 of this procedure. Persons failing to pass a re-qualification test are not allowed to make that type of joint until they successfully re-qualify. Supervisors are responsible for ensuring personnel performing plastic fusion in their area are properly qualified.

3. VISUAL INSPECTION OF JOINTS

Each test joint shall be visually inspected during and after assembly or joining. A joint may be failed upon visual inspection.

4. DESTRUCTIVE TESTING OF FUSION JOINTS

Test joints made during training and re-qualification passing the visual inspection must also pass one of following destructive test procedures. Allow all test joints to cool completely before destructively testing.

4.1 Butt Fusion Joints

a. Prepare at least three test straps by cutting lengthwise through joint.

b. Bend each strap until the ends of the strap touch, and examine the weld zone for voids, cracks or separation.

c. The joint being tested passes if all specimens do not show any signs of failure within the weld zone.

4.2 Socket Heat Fusion

Socket heat fusion joints may be tested by either of the following test methods.

4.2.1 Strap Test

a. Prepare at least three test straps by cutting lengthwise through joint.

b. Bend each strap until the ends of the strap touch.

c. Visually inspect the joint for any indications of voids, gaps, misalignment or surfaces that have not been properly bonded.

d. The joint being tested passes if there are no signs of failure within the weld zone.

4.2.2 Joint Crush Test

a. Cut the coupling and pipe in half lengthwise along the centerline of the pipe.

b. Place pipe halves in vise and tighten jaws until inside walls of pipe touch.

c. With specimen held in vise examine weld zone for any voids, cracks or separation.

d. The joint being tested passes if there are no signs of failure within the weld zone.

4.3 Electrofusion Coupling

Electrofusion coupling joints may be tested by either of the following test methods.

4.3.1 Strap Test

a. Prepare three test straps by cutting joint lengthwise along main pipe and through the coupling.

b. Bend each test strap until the ends of the strap touch.

c. Visually inspect the joint for any indications of voids, gaps, or surfaces that have not been properly bonded.

d. The joint being tested passes if there are no signs of failure within the weld zone.

4.3.2 Joint Crush Test

a. Cut the coupling and pipe in half along the centerline of the pipe, place pipe in vise so outermost wire in coupling is approximately 1-1/4" from vise jaws, tighten the jaws on the pipe until the inner walls of the pipe meet.

b. With the pipe still held in the vise, visually inspect the joint area for signs of separation of the fitting from the pipe. Some minor separation at the outer limits of the fusion heat source is acceptable. Ductile failure in the pipe, fitting, or the wire insulation material is acceptable as long as the bond interface remains intact.

c. Repeat steps (a) and (b) above, for both ends of each half coupling that was cut in step (a) for a total of four crush tests.

d. Failure of any one of the four crush tests constitutes failure of the joint being tested.

4.4 Electrofusion Saddle Fitting

Electrofusion saddle joints may be tested by either of the following test methods.

4.4.1 Strap Test

a. Prepare three test straps by cutting joint lengthwise along main pipe and through base of the fitting.

b. Bend each strap until the ends of the strap touch.

c. Visually inspect the joint for any indications of voids, gaps, or surfaces that have not been properly bonded.

d. The joint being tested passes if there are no signs of failure within the weld zone.

4.4.2 Joint Crush Test

a. Place pipe in vise jaws so saddle bottom is within ½" of vise jaws, tighten the vise jaws until the inner walls of the pipe meet.

b. With the pipe still held in the vise, visually inspect the joint area for signs of separation of the fitting from the pipe. Some minor separation at the outer limits of the fusion heat source is acceptable. Ductile failure in the pipe, fitting, or the wire insulation material is acceptable as long as the bond interface remains intact.

c. Repeat steps (a) and (b) above for the other side of the saddle joint.

d. Failure of either one of the crush tests constitutes failure of the joint being tested.

4.4.3 Impact Test

a. Position pipe with saddle fitting vertically in test apparatus and secure to prevent movement during impact.

b. Drop weight or impact with hammer until failure occurs.

c. Tearing in the pipe wall or fitting is acceptable. Any tearing or separation in the weld zone is considered a failure.

5. RECORDS

Qualification records are maintained for each person responsible for making plastic joints. Individuals that do not pass the re-qualification test for any type of plastic joint, shall not be allowed to make that type of joint until they are properly qualified in accordance with this procedure.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	**Butt Fusion Joining**	Standard Number: **GS 1302.010**
Supersedes: 01/19/2010		Page 1 of 13

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

Refer to Operational Notice ON 15-02 for additional information for 12 inch pipe (Effective 07/01/2015).

REFERENCE 49 CFR Part 192.283, 192.285, 192.287

1. GENERAL

This procedure is to be followed for the butt fusing of ASTM D 2513 polyethylene pipe and fittings. Only medium density polyethylene pipe and fittings with the designation PE 2406, PE 2708, and high density polyethylene pipe and fittings PE 3408, PE 4710 can be fused using this procedure. The PE designations as shown above appear in the print line on the pipe or on the fitting label. Medium density pipe or fittings cannot be fused to high density pipe or fittings using this procedure. Use an electrofusion coupling to join medium density pipe to high density pipe.

Do not use this procedure to butt fuse Uponor (Dupont) Aldyl "A" or Phillips Driscopipe 7000/8000. Use electrofusion or mechanical fittings to join all other types of polyethylene pipe and fittings to Uponor (Dupont) Aldyl “A” or Phillips Driscopipe 7000/8000.

2. BUTT FUSION PARAMETERS

The following butt fusion parameters shall be used when performing the butt fusion.

Table 1 Butt Fusion Parameters

Heater Surface Temperature	400° - 450°F
Fusion Interfacial Pressure	60 - 90 psi

3. COLD OR INCLEMENT WEATHER CONSIDERATIONS

In cold weather (ambient temperatures below 40 ºF) and in inclement weather (especially windy conditions), the fusion operation shall be shielded to avoid precipitation or blowing snow and excessive heat loss from the wind. To ensure the proper heating tool temperature is maintained the heating tool should be stored in an insulated container to prevent excessive heat loss. Sheltering the fusion area from the wind or using catalytic heater to warm the pipe should be considered. The heating tool can also be placed in the machine and then the pipe moved so the ends are within ½ inch of the heating tool face to warm the pipe. Remove all frost, snow, or ice from the outer diameter (OD) and inner diameter (ID) of the pipe and fittings to be joined. All surfaces shall be clean and dry prior to fusing.

The time required to obtain the proper melt may increase when fusing in cold weather. The following recommendations should be followed.

a. Maintain the specified heating tool surface temperature. Do not increase the tool surface temperature.

b. Do not apply pressure during zero pressure butt fusion heating steps.

c. Do not increase the butt fusion joining pressure.

4. COILED PIPE

When joining coiled pipe, create an S-curve between the pipe coils to relieve stress.

5. MITERED JOINTS

Mitered butt fusion joints between pipes, or pipe and a fitting are not permitted.

6. DISSIMILAR WALL THICKNESSES

Butt fusion of pipe, or pipe and fittings, with dissimilar wall thicknesses is not permitted. The wall thickness or Standard Dimension Ratio (SDR) of pipe and butt fusion fittings must be the same when butt fusing pipe or pipe and fittings.

7. MARKERS

Markings on the pipe shall be made with a non-petroleum based marker as listed below.

a. Any brand of permanent type marker (e.g., Sharpie, Marks-A-Lot & Magic Marker).

b. Any brand of fast drying paint pens (e.g., Pentel and Faber Castell).

Grease pens are petroleum based and shall not be used

8. BUTT FUSION PROCEDURE

The principle of heat fusion is to heat two surfaces to a designated temperature, and then fuse them together by application of a sufficient force. This force causes the melted materials to flow and mix, thereby resulting in fusion. When fused according to the proper procedures, the joint area becomes as strong as or stronger than the pipe itself in both tensile and pressure properties.

Field-site butt fusions may be made readily by trained operators using butt fusion machines that secure and precisely align the pipe ends for the fusion process. Each type of fusion requires special tools and equipment. Fusions performed with the incorrect fusion equipment, materials or tools can result in a poor fusion. All required tools for making butt fusions should be on site and in proper working order before use.

Before starting the joining process below, clean the pipe surface with clean water and a cloth to remove any dirt and contaminants. Approved alcohol wipes may also be used for this step. When cleaning dirt or mud from the pipe surface ***ONLY*** use clean water. When using clean water in freezing temperatures, follow up by using an approved alcohol wipe to remove any ice film that may have formed. ***NEVER*** use leak detecting solution, detergents, solvents, etc., to clean pipe for fusion.

If at any point in the fusion process the fusion surfaces become contaminated stop and re-start the process from the beginning.

The seven steps involved in making a butt fusion joint are:

a. securely fasten the components to be joined,
b. face the pipe ends,
c. align the pipe profile,
d. melt the pipe interfaces,
e. join the two profiles together,
f. hold under pressure, and
g. visual inspection.

8.1 Secure

Clean the inside and outside of the pipe to be joined by wiping with a clean lint-free cloth. Remove all foreign matter. Clamp the components in the machine. Check alignment of the ends and adjust as needed.

8.2 Face

The pipe ends must be faced to establish clean, parallel mating surfaces. Most, if not all, equipment manufacturers have incorporated the rotating planer block design in their facers to accomplish this goal. Facing is continued until a minimal distance exists between the fixed and movable jaws of the machine and the facer is locked firmly and squarely between the jaw bushings. This operation provides for a perfectly square face, perpendicular to the pipe centerline on each pipe end and with no detectable gap.

8.3 Align

Remove any pipe chips from the facing operation and any foreign matter with a clean, untreated, lint-free cotton cloth. The pipe profiles must be rounded and aligned with each other to minimize mismatch (high-low) of the pipe walls. This can be accomplished by adjusting clamping jaws until the outside diameters of the pipe ends match. The jaws must not be loosened or the pipe may slip during fusion. To visually inspect for pipe movement during the joining of the two ends, it is recommended that the pipe be marked at the outer edge of both clamps. Re-face the pipe ends and remove any chips from re-facing operation with a clean, untreated, lint-free cotton cloth.

8.4 Melt

Heating tools that simultaneously heat both pipe ends are used to accomplish this operation. These heating tools are normally furnished with thermometers to measure internal heater temperature so the operator can monitor the temperature before each joint is made. However, the thermometer can be used only as a general indicator because there is some heat loss from internal to external surfaces, depending on factors such as ambient temperatures and wind conditions. A pyrometer or other surface temperature-measuring device should be used prior to the first fusion of the day and any time power is interrupted to a heating tool to insure proper temperature of the heating tool face. Temperature indicating crayons shall not be used to check surface temperature of heating tools. Additionally, heating tools are usually equipped with suspension and alignment guides that center them on the pipe ends. The heater faces that come into contact with the pipe should be clean, oil-free and coated with a nonstick coating as recommended by the manufacturer to prevent molten plastic from sticking to the heater surfaces. Remaining molten plastic can interfere with fusion quality and must be removed according to the tool manufacturer's instructions.

The surface temperatures must be in the temperature range 400-450°F. Install the heater in the butt fusion machine and bring the pipe ends into full contact with the heater. To ensure that full and proper contact is made between the pipe ends and the heater, the initial contact should be under moderate pressure (excessive pressure will result in a concave surface). After holding the pressure very briefly, it should be released without breaking contact. On larger pipe sizes, initial pressure may be maintained until a slight melt is observed around the circumference of the pipe before releasing pressure. Continue to hold the components in place, without force, while a bead of molten polyethylene develops between the heating tool and the pipe ends. When the proper bead size is formed against the heating tool surfaces, remove the heating tool. Melt bead size is dependent on pipe size. See Table 2 below for approximate melt bead sizes.

Table 2
Approximate Melt Bead Size

Pipe Size	Approximate Wall Thickness	Melt Bead Size* (Approximate)
2”,	0.15” – 0.30”	1/16”
3”, 4”, 6”	Above 0.30: - 0.75”	1/8” – 3/16”
8”, 10”	Above 0.75” – 1.15”	3/16” – ¼”
10” **	Above 0.75” – 1.15”	3/16” – ¼”
12” **	Above 1.15” – 1.60”	¼” – 5/16”

* The appearance of the melt swell zone may vary depending on the pipe material. The melt bead width is to be determined by measuring the distance from the heater plate to the melt swell origin.

** Contact engineering for additional procedure requirements before fusing 10” or 12” size plastic pipe.

8.5 Joining

After the heater tool is removed, quickly inspect the pipe ends, then immediately bring the molten pipe ends together with sufficient fusion force to form a double rollback bead against the pipe wall. (NOTE: If a concave melt surface is observed, unacceptable pressure during heating has occurred and the joint will be low quality. Do not continue. Allow the component ends to cool completely, and restart at the beginning. Except for a very brief time to seat the components fully against the heating tool, do not apply pressure during heating.).

Fusion force is determined by multiplying the interfacial pressure, 60-90 psi, by the pipe area. For manually operated fusion machines, a torque wrench can be used to accurately apply the proper force. For hydraulically operated fusion machines, the fusion force can be divided by the total effective piston area of the carriage cylinders to give a hydraulic gauge reading in psi. The gauge reading is theoretical; internal and external drags are added to this figure to obtain the actual fusion pressure required by the machine. The hydraulic gauge reading and the interfacial pressure are not the same value. For additional guidance on hydraulically operated fusion machines see Section 10.

8.6 Hold

Hold the molten joint immobile under 60-90 psi interfacial fusion pressure until cooled adequately to develop strength. Allowing proper times under pressure for cooling prior to removal from the clamps of the machine is important in achieving joint integrity. The fusion force should be held between the pipe ends for approximately 30-90 seconds per inch of pipe diameter or until the surface of the bead is cool to the touch. Avoid pulling, installation or rough handling for an additional 30 minutes.

8.7 Visual Inspection

When completed, each joint shall be visually inspected for proper bead size, appearance and uniformity. Table 3 provides general guidelines for proper finish bead widths. The photographs provide guidance for visually inspecting the finish bead for acceptable appearance and uniformity. On both sides, the double bead shall be rolled over to the surface, and be uniformly rounded and consistent in size all around the joint. Photographs of acceptable and unacceptable butt fusions are shown in Section 9. Any butt fusion joint that fails a visual inspection must be cut out as a cylinder and replaced. Repair of a defective butt fusion joint is prohibited.

A butt fusion troubleshooting guide is provided in Section 11.

8.8 Operator Identification

When fusing plastic pipe or fittings, print the date the fusion was made and the employee/contractor ID, e.g. NiSource employee I.D. number, of the person performing the fusion on the pipe.

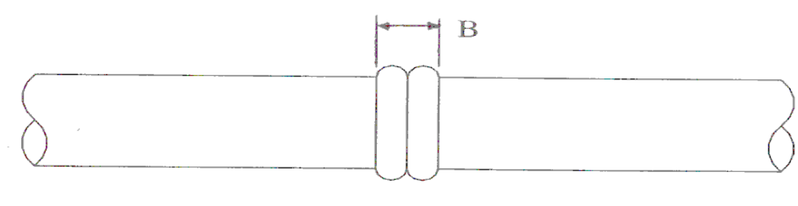
Table 3
Approximate Finish Bead Widths* Per Wall Thickness **

Pipe Size (IPS) (inches)	SDR	Minimum Wall Thickness (inches)	Approximate Bead Width (B), Minimum (inches)	Approximate Bead Width (B), Maximum (inches)
2	11.0	0.216	3/16	5/16
3	11.0	0.318	9/32	3/8
3	11.5	0.304	¼	11/32
4	11.0	0.409	5/16	7/16
4	11.5	0.395	5/16	7/16
6	11.0	0.602	3/8	9/16
6	11.5	0.576	3/8	9/16
6	13.5	0.491	11/32	1/2
8	11.0	0.784	½	11/16
8	13.5	0.639	7/16	19/32
10	11.0	0.977	9/16	¾
10	13.5	0.796	½	11/16

Instructions:

* Determine the pipe size and SDR or wall thickness of the pipe/fitting. Find the corresponding pipe size and SDR or wall thickness above. For other wall thickness contact the appropriate pipe manufacturer

** Derived from Polypipe's Heat Fusion Joining Procedures Revised 04/2005.

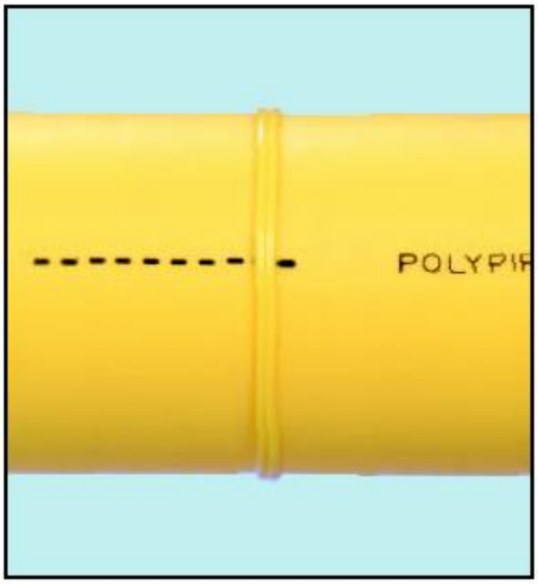


9. PHOTOGRAPHS OF ACCEPTABLE AND UNACCEPTABLE BUTT FUSIONS

Acceptable

Proper alignment and double roll-back bead.

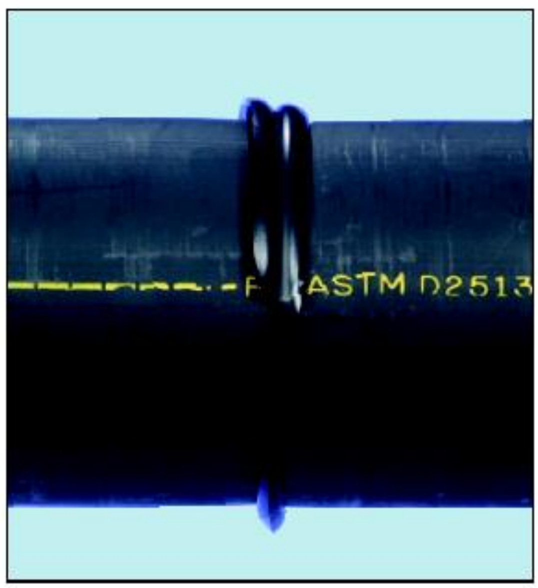
Unacceptable



Melt bead too small due to insufficient heat time.

Melt bead too large due to excessive heating and/or over-pressurizing of joint.

Misalignment.



Incomplete facing.

10. HYDRAULICALLY OPERATED FUSION MACHINE CONSIDERATIONS

When performing a butt fusion using a hydraulically operated fusion machine, in addition to the procedures listed above, consider the following important items:

a. Fusion Interfacial Pressure Range 60 - 90 psi;

b. Hydraulically operated fusion machine must remain running and the control valve in the joining position during the cool down cycle in order to maintain constant pressure on the joint until the cool time has expired;

c. Key factors necessary to determine the correct fusion pressure setting (see Table 4) are pipe diameter, pipe wall thickness or SDR, machine piston area (cylinder area), and interfacial pressure;

d. Since larger diameter pipe (normally 6" and greater) is heavier than smaller diameter pipe drag pressure, the hydraulic pressure required to move the carriage while holding the pipe, is a very important factor in determining proper fusion pressures. Drag pressure must always be added to the fusion pressure setting to produce an acceptable joint;

e. Hydraulically operated fusion machines have four hold down clamps as opposed to two for smaller (manual) machines. Highs and lows are adjusted using the inner clamps. To visually inspect for pipe movement during the joining of the two ends, it is recommended that you mark the pipe at the outer edge of one or both clamps;

f. During the heating cycle, the machine must be set in the neutral position. This is referred to as the "heat soak" position;

g. Pipe supports/roller stands are recommended in order to properly align the pipe ends and to avoid excess pressure on the machine hold down clamps; and

h. Always check for proper hydraulic fluid levels prior to using the hydraulically operated fusion machine. This level should be re-checked periodically during the day. Also look for spills or leaks which could be an indication of a problem and could affect the operation of the cylinders.

Hydraulic pressures for selected hydraulically operated fusion machines are given in Table 4 below. This information is provided as a guide and was calculated using the following formula and parameters:

OD - means Outside Diameter

t - means Wall Thickness

SDR - means Standard Dimensional Ratio

IFP - means Interfacial Pressure

TEPA - means Total Effective Piston Area

Total Effective Piston Area (TEPA) for Various Hydraulic Machines

TD – 86	BF – 86C	Connectra and McElroy
1.958	1.595	4.710

Formulas:

t = OD/SDR

Gauge Pressure = (((OD - t) x t x 3.1416 x IFP) / TEPA) + Drag Pressure

Table 4

Gauge Pressure Range (PSI)

Note: Values shown below <u>do not</u> include a drag pressure. Refer to manufacturer's recommended hydraulic pressures. Drag force is a variable that should be determined on a case-by-case basis and accounted for before the joining force is applied. If two long pieces of pipe are being fused, the drag force can be several hundred pounds.

PIPE SIZE	SDR	TD-86	BF-86C	CONNECTRA 28EP AND McELROY 28
		60 IFP – 90 IFP	60IFP - 90IFP	60IFP - 90IFP
2" (2.375)	11	45 - 67	55 - 83	19 – 28
2" (2.375)	13.5	37 - 56	46 - 69	15 – 23
3" (3.5)	11	97 – 146	120 – 179	40 – 61
3" (3.5)	11.5	94 – 140	115 - 172	39 – 58
4" (4.5)	11	161 - 242	198 - 297	67 – 100
4" (4.5)	11.5	155 - 232	190 - 285	64 – 96
4" (4.5)	13.5	134 - 200	164 - 246	56 – 83

Table 4

Gauge Pressure Range (PSI)

Note: Values shown below <u>do not</u> include a drag pressure. Refer to manufacturer's recommended hydraulic pressures. Drag force is a variable that should be determined on a case-by-case basis and accounted for before the joining force is applied. If two long pieces of pipe are being fused, the drag force can be several hundred pounds.

PIPE SIZE	SDR	TD-86	BF-86C	CONNECTRA 28EP AND McELROY 28
6" (6.625)	11	350 - 524	429 - 644	145 – 218
6" (6.625)	11.5	336 - 504	412 - 619	140 – 210
6" (6.625)	13.5	290 - 436	357 - 535	121 – 180
8" (8.625)	11	592 - 888	726 - 1090	246 – 369
8" (8.625)	11.5	569 - 853	698 - 1047	236 – 355
8" (8.625)	13.5	491 - 737	603 - 905	204 – 306
10" (10.750)	11.0	919 – 1379	1128 – 1693	382 – 573
10" (10.750)	11.5	883 – 1325	1085 – 1627	367 – 551
10" (10.750)	13.5	763 - 936	936 - 1405	317 – 476

11. BUTT FUSION TROUBLESHOOTING GUIDE

Table 5

Butt Fusion Troubleshooting Guide

Observed Condition	Possible Cause
• Excessive double bead width	• Overheating • Excessive joining force
• Double bead v-groove too deep	• Excessive joining force • Insufficient heating • Pressure during heating
• Flat top on bead	• Excessive joining force • Overheating
• Non uniform bead size around pipe	• Misalignment • Defective heating tool • Worn equipment • Incomplete facing
• One bead larger than the other	• Misalignment • Component slipped in clamp • Worn equipment • Heating iron does not move freely in the axial direction • Defective heating tool • Incomplete facing
• Beds too small	• Insufficient heating • Insufficient joining force
• Bead not rolled over to surface	• Shallow v-groove – Insufficient heating & insufficient joining force • Deep v-groove – Insufficient heating and excessive joining force
• Bead too large	• Excessive heating time
• Square type outer bead edge	• Pressure during heating
• Rough sandpaper-like bubbly, or pockmarked melt bead surface	• Hydrocarbon (gasoline vapors, spray paint fumes, etc.) contamination

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/22/2016	Electrofusion Joining	Standard Number: **GS 1304.010**
Supersedes: 01/01/2015		Page 1 of 16

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.283, 192.285, 192.287

1. GENERAL

Pipe preparation and contamination are very important considerations to the electrofusion process. Careful attention must be given to proper scraping and cleaning procedures. The following procedures shall be followed.

Electrofusion fittings shall be used when fusing high density to medium density plastic pipe or high density to Aldyl A plastic pipe. Electrofusion fittings shall be used for fusing medium density to Aldyl A plastic pipe.

Electrofusion high-volume service punch tees and service punch tee are preferred for making branch or service connections on all medium-density, high-density and Aldyl A plastic pipe.

Prior to joining visually inspect all pipe and fittings in accordance with GS 3000.020 "Inspection of Materials."

2. SAFETY AND FIELD PRECAUTIONS

a. All employees shall be out of the excavation before starting the fusion process.

b. Treat electrical equipment as a potential source of ignition in a gaseous atmosphere.

c. Install a purge point on the pipe if there is a possibility of a pressure build-up in the pipe during the installation and fusion of a coupling. A service tee and approved purge assembly may be used.

d. Keep all electrofusion fittings in their original packaging until they are ready to be installed.

e. Do not touch or contaminate the heating element of the fitting. If the heating element becomes contaminated, clean it with an approved alcohol wipe.

f. When storing the electrofusion processor, avoid sharp bending and knotting of the output leads and power cord.

3. ELECTROFUSION PROCESSORS & GENERATORS

Only Company approved electrofusion processors can be utilized to perform the electrofusion process. Refer to the manufacturer's instructions for the operation and proper generator size for the processor to be used. A 5.0 KVA generator will supply sufficient power for most electrofusion applications. Inverters are an acceptable AC power source if they meet the manufacturer specified power requirements. Inverters need to be "primed" with a power source such as a night-light to ensure adequate RPMs.

Follow manufacturer's recommendations regarding electrical supply to the electrofusion processor. Electrofusion processors should be plugged directly into the twist lock outlet on each truck. If this cannot be accomplished, the use of twist lock extension cords are permitted in maximum lengths of 25 feet for 12 gauge wire and 50 feet for 10 gauge wire. Due to the voltage drop, the use of Marine adapters should be avoided.

Electrofusion processors shall be maintained and calibrated in accordance with manufacturer's instructions. Maintenance records shall be kept in the work management system or other applicable filing system.

4. COLD OR INCLEMENT WEATHER CONSIDERATIONS

Electrofusion processors shall only be used when ambient temperatures are within the operating temperature range specified by the manufacturer. The electrofusion processor and/or leads measure the work-site temperature to supply the fitting with the proper energy. To assure the processor and/or leads are measuring correct work-site temperature, locate them so that it is exposed to work-site conditions as per manufacturer's instructions.

Prior to assembling joints, the fittings and electrofusion processor must be conditioned to the temperature at the work site. Precautionary measures may be necessary to assure satisfactory joining at ambient temperatures below 0° F. These can be as simple as providing shelter from the wind or using catalytic heaters to warm the joint area.

> NOTE: When electrofusing M.T. Deason fittings at ambient temperatures below 10° F, barcode mode or manual barcode mode shall be used, which will automatically add fusion time to the base fusion time of the fitting to compensate for very low ambient temperatures.

When using clean water in freezing temperatures for pre-cleaning pipe prior to preparation, follow up by using an approved alcohol wipe to remove any ice film that may have formed.

In inclement weather and especially in windy conditions, the fusion operation shall be shielded to avoid precipitation or blowing snow and excessive heat loss from the wind.

5. CONDITIONS APPLICABLE TO ALL ELECTROFUSION JOINTS

5.1 Joint assembly

Prior to fusion, the joint assembly must be correct. Refer to the manufacturer's instructions for correct assembly guidelines. Also, check the generator fuel supply to ensure the fusion cycle will not be interrupted.

5.2 Improper Fitting Identification

The electrofusion processor will display either the fitting identification or the fusion time depending on the mode of operation. Verify the correct information is displayed prior to starting the fusion process.

If an incorrect fitting identification displays, perform the following steps.

1. Press the stop or reset button.
2. Disconnect both leads from the fitting and inspect the fitting terminals and output leads for dirt or debris. In universal/resistor pin mode ensure the leads are connected to the proper terminals, i.e., red lead to resistor pin terminal.
3. If using barcode mode, verify the correct barcode label is being scanned.
4. Confirm that the ends of the leads are screwed on tightly and the proper code is being used.
5. If the incorrect fitting information is still displayed, select a new fitting and restart the process.

6. MARKERS

Markings on the pipe shall be made with a non-petroleum based marker as listed below.

a. Any brand of permanent type marker (e.g., Sharpie, Marks-A-Lot & Magic Marker).
b. Any brand of fast drying paint pens (e.g., Pentel and Faber Castell).

Grease pens are petroleum based and shall not be used.

7. SCRAPING TOOLS

7.1 Acceptable Scraping Tools

The following scraping tools are acceptable for preparing plastic pipe for an electrofusion joint.

a. Tools specifically designed for electrofusion scraping.
b. A Stanley Surform, Model 21-296 or equivalent.
c. A metal blade paint scraper.

7.2 Unacceptable Scraping Tools

The following tools shall not be used for electrofusion scraping.

a. Wood rasps.

b. Metal files or metal file type of rasp.

c. Sandpaper, emery cloth or other abrasives.

d. Knife.

8. SURFACE PREPARATION APPLICABLE TO ALL ELECTROFUSION JOINING

Surface contamination is one of the leading causes of electrofusion joint failure. Insufficient cleaning and scraping can leave contaminants and oxidation on the surface of the pipe that can lead to a fusion failure. Introduction of contaminates can also occur during the process to prepare the pipe and fitting for fusion. It is imperative to maintain clean surfaces on both the pipe and fitting during the entire electrofusion process.

8.1 Cleaning

a. Clean the pipe surface with clean water and a clean cloth to remove any dirt and contaminants. Approved alcohol wipes may also be used for this step.

b. When cleaning dirt or mud from the pipe surface ***ONLY*** use clean water.

c. When using clean water in freezing temperatures, follow up by using an approved alcohol wipe to remove any ice film that may have formed.

d. ***NEVER*** use leak detecting solution, detergents, solvents, etc., to clean pipe for fusion.

e. Approved alcohol wipes can be used for final cleaning prior to marking and scraping.

f. The pipe surface adjacent to the area to be scraped should also be cleaned to avoid transfer of contaminants by scraping tools or contact with loose fitting packaging.

8.2 Marking the Surface to be Scraped

a. Leave the fitting in the packaging when placing on the pipe for marking and use a non-petroleum based marker or fast drying paint pen to outline the area to be scraped. Use the same marker to fill-in the outline area with additional marks.

b. See examples of correct pipe marking in Exhibit A.

8.3 Scraping

a. Scraping is performed to entirely remove oxidation and contaminants so that virgin surface is exposed on the pipe surface.

b. Inspect the scraper blade and wheels to ensure they are clean and free of dirt and debris. When dirt or debris is found on the scraper blade or wheels, clean with a brush.

c. Clean the scraper blade with an approved alcohol wipe and allow to dry completely prior to each use.

WARNING: Proper PPE - Hand protection required. Approved cut-resistant gloves shall be worn when cleaning the scraper blade.

d. If a coupling is to be pushed completely over one pipe end, scrape the pipe end for the entire length of the coupling to prevent contamination of the coupling by sliding over un-scraped pipe.

e. During the scraping process make sure the ribbon removed by the scraper does not come in contact with the scraped surface as it can transfer surface contamination to the scraped area.

f. Ensure ALL traces of marks have been removed during scraping.

g. CAUTION: It should be noted, that water cannot be used to clean the pipe once it has been scraped. In those instances, an approved alcohol wipe**,** can be used to remove any contamination and is recommended as a cleaning agent that can be used before and after scraping.

8.4 Avoiding Contamination

a. Avoid touching the scraped pipe surface or the bottom of the fittings as body oils and other contaminates can affect the fusion joint. If the surfaces become contaminated, clean thoroughly with an approved alcohol wipe and allow to dry completely.

b. Do not wipe or touch the scraped surface of the pipe with anything, including clean rags or towels.

c. Do not remove the fitting from the packaging until you are ready to place the fitting on the pipe to secure the fitting.

d. Do not touch the fusion surface of the fitting.

e. If the fusion surface of the fitting is touched or otherwise contaminated, clean it with an approved alcohol wipe and allow to completely dry before placing it on the pipe.

9. FITTING RESTRAINT (STRAPPING, UNDERSADDLE, CLAMPING)

Secure the fitting to restrict movement during the fusion and cooling process. Also, it is designed to alleviate or eliminate sources of stress and/or strain until the fusion and clamping cycles are complete.

9.1 COUPLINGS & REDUCERS

All electrofusion couplings shall be secured and supported during the fusion process and for the extent of the manufacturer's recommended clamping time.

Clamps shall have a ridged base and cold ring type clamp or strap that holds the pipe in alignment on both sides of the fitting. Vise-grip type clamps may be used for small pipe sizes.

9.2 SADDLE FITTINGS

All electrofusion saddle type fittings (tapping tees, high volume tapping tees and branch saddles) shall be secured and supported during the fusion process and for the extent of the manufacturer's recommended clamping time.

Saddle type fittings shall be secured to restrict movement.

10. RE-FUSING FITTINGS

Electrofusion fittings can be re-fused only in the event of an input power interruption such as the fusion leads were detached during fusion, the generator runs out of gas, the electrofusion processor malfunctions or other circumstance that results in processor input power interruption.

Fittings that do not complete their fusion cycle for any other reason than listed above, shall be cut out and replaced, or abandoned. A fitting may be re-fused one time only. If any failure occurs during the re-fusion process the fitting shall be cut-out and replaced or abandoned. If a fitting such as a tapping tee is abandoned in place, remove the cap and cutter and cut the top of the tee off to ensure it is not usable.

The correct re-fusing procedure is as follows.

1. Ensure that all problems and conditions have been cleared before re-fusing a fitting.

2. Disconnect the electrofusion processor leads from the fitting.

3. The fitting shall remain secured to the pipe and allowed to cool for a minimum time equal to the total cooling time to rough handling shown in Table 1 or Table 2, as applicable.

4. After the total cooling time has elapsed, check the surface of the fitting over the heating coil area with a surface temperature measuring device. Compare this temperature with the temperature of the surface of the pipe six (6) or more inches away from the fitting. When these two (2) temperatures are the same the fitting is ready to attempt re-fusing.

5. Connect the leads from the electrofusion processor to the fitting, scan the bar code or check fitting label, check the display on the processor to ensure it matches the fitting being fused and press the start button to fuse the fitting for its entire fusion time.

6. When the fusion cycle is complete add the clamping time displayed on the processor to the time and day and write it on the pipe or fitting. Do not remove the restraint device until that written time has passed.

7. Once the restraint device is removed visually inspect the coupling or saddle base to be sure the fitting is seated and aligned properly and within the scraped area.

8. Additional cooling time is needed before pressure testing, tapping or rough handling. Refer to Table 1 or Table 2, as applicable, for proper times.

11. FUSION PROCEDURE FOR COUPLINGS

When making an electrofusion joint using a coupling, the following sequence shall be followed.

1. Clean the pipe ends with clean water and a clean cloth to remove all dirt, mud and contaminants. An approved alcohol wipe may also be used for this step.

2. Cut the pipe ends squarely with a blade type cutter, a wood saw or a tubing cutter. Any burrs or shavings remaining on the pipe ends must be removed.

   Ensure the pipe ends are clean inside and outside. Clean pipe surface as needed with clean water and a clean cloth to remove any dirt and contaminants. Approved alcohol wipes may be also be used for this step.

3. With the coupling still in the packaging use an approved marker to mark the proper depth of insertion (half the couplings length), from the end of each pipe or fitting to be fused to ensure centering of the coupling. Additional markings shall be placed over the area to be scraped to assist with scraping assurance. See marking examples in Exhibit A.

4. Using an approved scraping tool, clean the scraper blade with an approved alcohol wipe and allow to dry completely prior to each use.

   WARNING: Proper PPE - Hand protection required. Approved cut-resistant gloves shall be worn when cleaning the scraper blade.

5. Scrape the outside surface of each pipe end or fitting to be fused up to the stab depth marks to remove oxidation and contaminates, including shavings, so a virgin surface is exposed. Inspect the entire scraped area to ensure all traces of marks have been removed.

NOTE: If a coupling is to be pushed completely over one pipe end, scrape the pipe end for the entire length of the coupling to prevent contamination of the coupling by sliding over un-scraped pipe.

6. Avoid touching the scraped pipe or fitting surface or the inside of the coupling as body oils and other contaminates can affect the fusion joint. If the surfaces become contaminated, clean thoroughly with an approved alcohol wipe and allow to dry completely.

   NOTE: Do not use water during this step.

7. With the coupling still in the packaging, re-mark the proper depth of insertion (half the couplings length) on each pipe end or fitting to ensure centering of the coupling.

8. Install the coupling on the pipe and/or fitting so it is centered on the area to be fused. Install a line up clamp as close to the fitting as possible. Larger size couplings may require the use of a rubber mallet to move the coupling on the pipe.

   One end of the pipe should be secured in an appropriate restraint device, and the fitting slid onto the pipe. The second piece of pipe should be placed into the line-up clamp so that it is properly aligned. The fitting should then be positioned onto each pipe equally using the markings on the pipe as a guide.

9. Ensure a tight uniform fit all the way around the edges of the fitting. If gaps are found it may be necessary to re-round the pipe to ensure a satisfactory fit.

10. Start the power source, plug in the power cable to the electrofusion processor, turn the processor on and wait for it to run diagnostics.

11. Attach the leads from the electrofusion processor to the fitting and scan the barcode if using an electrofusion processor with a barcode scanner. If using a universal processor and a coupling with resistor pins the processor will automatically identify the fitting. Otherwise attach the leads to the fitting and manually input the code numbers from the label on the fitting.

12. Once the electrofusion processor has properly identified the fitting, press the start button and the processor will countdown the correct fusion time. When fusion time is complete, the processor will display the clamping (cooling) time. After display of the clamping (cooling) time, the electrofusion processor leads may be removed.

13. Add the clamping (cooling) time to the current time of day and write that time on the pipe or fitting. Do not remove the restraint device until that written time has passed.

14. Once the restraint device is removed visually inspect the coupling to be sure the fitting is seated and aligned properly and within the scraped area.

15. Print the date the fusion was made and the employee/contractor ID, e.g. NiSource employee I.D. number, of the person performing the fusion on the pipe.

16. Additional cooling time is needed before pressure testing, tapping or rough handling. Refer to Table 1 or Table 2, as applicable, for proper times.

17. Refer to GS 1500.010, GS 1500.010(MA), or GS 1500.010(OH) "Pressure Testing" for applicable test requirements.

12. FUSION PROCEDURE FOR SADDLE FITTINGS USING UNDER SADDLE OR CLAMP

When making an electrofusion with a saddle fitting using an under saddle or clamp, the following sequence shall be followed.

1. Clean the pipe surface with clean water and a clean cloth to remove any dirt and contaminants. An approved alcohol wipe may also be used for this step.

2. With the fitting still in the packaging place it on the pipe and trace the outline of the saddle base onto the pipe with an approved marker. Additional markings shall be placed in the outlined area to assist with scraping assurance. See examples of correct marking in Exhibit A.

3. Using an approved scraping tool, clean the scraper blade with an approved alcohol wipe and allow to dry completely prior to each use.

   WARNING: Proper PPE - Hand protection required. Approved cut-resistant gloves shall be worn when cleaning the scraper blade.

4. Scrape the marked pipe surface to remove oxidation and contaminants, including shavings, so that virgin surface is exposed. Inspect the entire scraped surface area to ensure all traces of marks have been removed.

5. Avoid touching the scraped pipe surface or the bottom of the saddle base as body oils and other contaminates can affect the fusion joint. If the surfaces become contaminated, clean thoroughly with an approved alcohol wipe and allow to dry completely.

   NOTE: Do not use water during this step.

6. Remove the fitting from the bag and position it on the scraped area of the pipe.

7. Clamp the fitting on the main ensuring a tight uniform fit all the way around the edges of the fitting. If gaps are found it may be necessary to re-round the pipe to

ensure a satisfactory fit.

8. Start the power source, plug in the power cable to the electrofusion processor, turn on the processor and wait for it to run diagnostics.

9. Attach the lead from the electrofusion processor to the fitting and scan the barcode if using a processor with a barcode scanner. If using a universal processor and a fitting with resistor pins the processor with automatically identify the fitting. Otherwise attach the leads to the fitting and manually input the code numbers from the label on the fitting.

10. Once the electrofusion processor has properly identified the fitting, press the start button and the processor will countdown the correct fusion time. When fusion time is complete, the processor will display the clamping (cooling) time. After display of the clamping (cooling) time, the electrofusion processor leads may be removed.

11. Add the clamping (cooling) time to the current time of day and write that time on the pipe or fitting. Do not remove the under saddle or clamp until that written time has passed.

12. Once the restraint device is removed visually inspect the saddle base to be sure the fitting is seated and aligned properly and within the scraped area.

13. Print the date the fusion was made and the employee/contractor ID, e.g. NiSource employee I.D. number, of the person performing the fusion on the pipe.

14. Additional cooling time is needed before pressure testing, tapping or rough handling. Refer to Table 1 or Table 2, as applicable, for proper times.

15. Refer to GS 1500.010, GS 1500.010(MA), or GS 1500.010(OH) “Pressure Testing” for applicable test requirements.

13. FUSION PROCEDURE FOR SADDLE FITTINGS USING TOP LOAD CLAMP

When making an electrofusion with a saddle fitting using a top load clamp, the following sequence shall be followed.

1. Clean the pipe surface with clean water and a clean cloth to remove any dirt and contaminants. An approved alcohol wipe may also be used for this step.

2. With the fitting still in the packaging place the fitting on the pipe and trace the outline of the saddle base onto the pipe with an approved marker. Additional markings shall be placed in the outlined area to assist with scraping assurance. See examples of correct marking in Exhibit A.

3. Using an approved scraping tool, clean the scraper blade with an approved

alcohol wipe and allow to dry completely prior to each use.

WARNING: Proper PPE - Hand protection required. Approved cut-resistant gloves shall be worn when cleaning the scraper blade.

4. Scrape the marked pipe surface to remove oxidation and contaminants, including shavings, so that virgin surface is exposed. Inspect the entire scraped surface area to ensure all traces of marks have been removed.

5. Avoid touching the scraped pipe surface or the bottom of the saddle base as body oils and other contaminates can affect the fusion joint. If the surfaces become contaminated, clean thoroughly with an approved alcohol wipe and allow to dry completely.

   NOTE: Do not use water during this step.

6. Remove the fitting from the bag, remove the cap and position it on the scraped area of the pipe.

7. Attach the top load clamp with the proper size fitting adapter attached across the top of the fitting and bottom of the pipe. Hold the fitting in place and lower the crossbar so the fitting is in contact with the scraped area on the pipe and lock the crossbar.

8. Turn the knob on the clamp clockwise to apply pressure to the fitting. Tighten until the indicator post located in the center of the knob is flush with the top of the knob. Be careful not to over tighten as it can reduce the necessary pressure on the outer cold zone of the fusion area. Ensure a tight uniform fit all the way around the edges of the fitting. If gaps are found it may be necessary to re-round the pipe to ensure a satisfactory fit.

9. Start the power source, plug in the power cable to the electrofusion processor, turn on the processor and wait for it to run diagnostics.

10. Attach the leads from the electrofusion processor to the fitting and scan the barcode if using an electrofusion processor with a barcode scanner. If using a universal processor and a fitting with resistor pins the processor will automatically identify the fitting. Otherwise attach the lead to the fitting and manually input the code numbers from the label on the fitting.

11. Once the electrofusion processor has properly identified the fitting, press the start button and the processor will countdown the correct fusion time. When fusion time is complete, the processor will display the clamping (cooling) time. After display of the clamping (cooling) time, the electrofusion processor leads may be removed.

12. Add the clamping (cooling) time to the current time of day and write that time on the pipe or fitting. Do not remove the top clamp until that written time has passed.

13. Once the clamping device is removed visually inspect the saddle base to be sure the fitting is seated and aligned properly and within the scraped area.

14. Print the date the fusion was made and the employee/contractor ID, e.g. NiSource employee I.D. number, of the person performing the fusion on the pipe.

15. Additional cooling time is needed before pressure testing, tapping or rough handling. Refer to Table 1 or Table 2, as applicable, for proper times.

16. Refer to GS 1500.010, GS 1500.010(MA), or GS 1500.010(OH) “Pressure Testing” for applicable test requirements.

Table 1 – Heating and Cooling Times* for Central Plastic Electrofusion Fittings

Fitting Description	Fusion Time (Seconds)	Clamped Time (Minutes)	Total Cooling Time** Before Pressurizing or Tapping (Minutes)	Total Cooling Time** Before Rough Handling (Minutes)
Coupling, 1/2" CTS	20	5	15	30
Coupling, 3/4" CTS	25	5	15	30
Coupling, 1" CTS	40	5	15	30
Coupling, 1-1/4" IPS	75	10	20	30
Coupling, 2" IPS	60	10	20	30
Coupling, 3" IPS	180	15	30	35
Coupling, 4" IPS	200	15	30	35
Coupling, 6" IPS	500	20	40	45
Coupling, 8" IPS	500	20	40	45
Coupling, 12" IPS	TC+	45	60	60
Coupling, 1" IPS x 1/2" CTS	25	5	15	30
Coupling, 1" IPS x 1" CTS	30	5	15	30
Coupling, 1" CTS x 1/2" CTS	30	5	15	30
Coupling, 1 1/4" IPS x 1" IPS	45	10	20	30
Cap, 1/2" CTS	20	5	15	30
Cap, 1 1/4" IPS	75	10	20	30
Ell, 2" IPS, 90° (EF adapted)	45 (20v)	5	20	30
Saddle, Branch, 2" IPS x 2" IPS	90	10	25	30
Saddle, Branch, 3" IPS x 2" IPS	60	10	25	30
Saddle, Branch, 4" IPS x 2" IPS	60	10	25	30
Saddle, Branch, 6" IPS x 2" IPS	60	10	25	30
Saddle, Branch, 8" IPS x 2" IPS (Yellow)	80	10	25	30
Saddle, Branch, 8" IPS x 2" IPS (Black)	240	20	30	40
Saddle, Branch, 4" IPS x 4" IPS	50	10	20	30
Saddle, Branch, 6" IPS x 4" IPS (Yellow)	150	15	30	45
Saddle, Branch, 6" IPS x 4" IPS (Black)	150	15	30	45
Saddle, Branch, 8" IPS x 4" IPS	TC+	20	40	60
Saddle, Branch, 8" IPS x 6" IPS	TC+	20	40	60
Tapping Tee, 1-1/4" IPS Saddle	45	10	20	30
Tapping Tee, 2" IPS Saddle	90	10	20	30
Tapping Tee, 3" IPS Saddle	90	10	20	30
Tapping Tee, 4" IPS Saddle	90	10	20	30
Tapping Tee, 6" IPS Saddle	90	10	20	30
Tapping Tee, 8" IPS Saddle	60	10	20	30

* For other approved brands of fittings refer to Table 2 or other manufacturer's instructions for times.

** Clamped Time, Cooling Time before Pressure/Tap, and Cooling Time before Rough Handling are cumulative. Therefore, total overall cooling time before rough handling is shown in the Total Cooling Time before Rough Handling column. Rough handling is considered placing the pipe in the ditch and backfilling.

+ These fittings require temperature compensation.

Table 1 – Heating and Cooling Times* for Central Plastic Electrofusion Fittings (continued)

Fitting Description	Fusion Time (Seconds)	Clamped Time (Minutes)	Total Cooling Time** Before Pressurizing or Tapping (Minutes)	Total Cooling Time** Before Rough Handling (Minutes)
Tee, High Volume, 2" IPS Saddle	90	10	25	30
Tee, High Volume, 3" IPS Saddle	60	10	25	30
Tee, High Volume, 4" IPS Saddle	60	10	25	30
Tee, High Volume, 6" IPS Saddle	60	10	25	30
Tee, High Volume, 8" IPS Saddle (Yellow)	80	10	25	30
Tee, High Volume, 8" IPS Saddle (Black)	240	20	30	40
Tee, High Volume, 12" IPS Saddle	240	20	30	40
Tee, 2" IPS, In-Line (EF adapted)	45 (20 v)	5	20	30

* For other approved brands of fittings refer to Table 2 or other manufacturer's instructions for times.

** Clamped Time, Cooling Time before Pressure/Tap, and Cooling Time before Rough Handling are cumulative. Therefore, total overall cooling time before rough handling is shown in the Total Cooling Time before Rough Handling column. Rough handling is considered placing the pipe in the ditch and backfilling.

+ These fittings require temperature compensation.

NiSource
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Effective Date: 04/22/2016	Electrofusion Joining	Standard Number: GS 1304.010
Supersedes: 01/01/2015		Page 15 of 16

Table 2 – Heating and Cooling Times* for M.T. Deason Electrofusion Fittings**

Fitting Description+	Fusion Time (Seconds)	Total Cooling Time++ in Clamp Position (Minutes)	Total Cooling Time++ Before Pressure Test & Rough Handling (Minutes)
Coupling, 1/2" CTS	40	5	15
Coupling, 3/4" CTS (Central Plastics)	25	5	30
Coupling, 3/4" IPS	40	5	15
Coupling, 1" IPS	50	10	20
Coupling, Reducing, (Pre-fabricated), 1 1/4" IPS x 1" CTS			
1 ¼" IPS end	30	5	15
1" CTS end	30	5	15
Coupling, Reducing, (Pre-fabricated / Kit), 1" CTS x 3/4" CTS			
1" CTS end	30	5	15
3/4" CTS end (Central Plastics Coupling)	25	5	30
Elbow, 1" CTS, 90˚	45	10	20
Elbow (Pre-fabricated), 1 1/4" IPS, 90˚			
1 1/4" IPS ends	30	5	15
In-Line Tee (Pre-fabricated), 1" CTS			
1" CTS ends	30	5	15
In-Line Tee (Pre-fabricated), 1 1/4" CTS			
1 1/4" IPS ends	30	5	15
Cap, 1" CTS	30	5	15
Saddle, Branch, 4" IPS x 4" IPS	220	10	25
Saddle, Branch, 6" IPS x 4" IPS	320	20	35
Saddle, Branch, 6" IPS x 6" IPS	300	20	35
Saddle, Branch, 8" IPS x 4" IPS	320	20	35
Saddle, Branch, 8" IPS x 6" IPS	360	20	35

* For other approved brands of fittings refer to Table 1 or other manufacturer's instructions for times.

** For other approved M.T. Deason electrofusion fittings, refer to manufacturer's instructions for times.

+ The M.T. Deason kits will come with loose electrofusion couplings and butt fusion fittings (e.g., elbow, tee). The M.T. Deason pre-fabricated fittings will come with butt fusions completed.

++ Total Cooling Time in Clamped Position and Total Cooling Time before Pressure Test & Rough Handling are cumulative. Therefore, total overall cooling time before pressure test & rough handling is shown in the Total Cooling Time before Pressure Test and Rough Handling column. Rough handling is considered placing the pipe in the ditch and backfilling.

NOTES:

a. M.T. Deason fittings require the use of barcode mode or manual barcode mode at ambient temperatures below 10° F to achieve temperature compensation. M.T. Deason recommends the use of barcode mode or manual barcode mode at all times.
b. M.T. Deason is providing fittings to NiSource in the following manner.
   i. Kits containing electrofusion coupling(s) with a butt fusion elbow, in-line tee, or cap. Fusion times are included above for the various sized electrofusion couplings that may be part of a kit.
   ii. Pre-fabricated fittings containing various other fittings, such as electrofusion by butt fusion adaptor(s) with factory made butt fusions to a butt fusion elbow or in-line tee. Fusion times are included above for the electrofusion end(s) of the adaptor(s).
   iii. Molded fittings. Fusion times are included above for each molded fitting.

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Gas Standard

Effective Date: 04/22/2016	Electrofusion Joining	Standard Number: **GS 1304.010**
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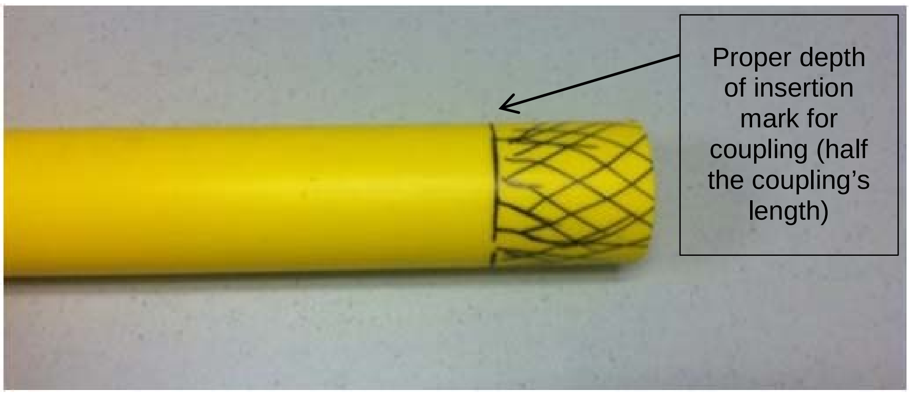
EXHIBIT A

Scrape Marking Examples



Coupling

Saddle Type Fitting

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Saddle Fusion Joining**	Standard Number: **GS 1306.010**
Supersedes: 01/19/2010		Page 1 of 1

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

NOTICE OF CANCELLATION

The above identified standard has been cancelled. Refer to GS 1304.010 “Electrofusion Joining,” for installation of service tapping tees and high volume tapping tees.

NiSource

Gas Standard

Distribution Operations

Effective Date: 01/01/2015	**Socket Fusion Joining**	Gas Standard: **GS 1308.010**
Supersedes: 01/01/2012		Page 1 of 6

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192.283, 192.285, 192.287

1. GENERAL

The socket fusion procedures that follow have been proven to consistently produce sound fusion joints when used correctly for joining medium density to medium density (MDPE) and high density to high density (HDPE) polyethylene materials. Socket fusion is permitted only between materials within the categories as defined in Table 2. Additionally, this procedure does not allow socket fusion joining ALDYL-A or Driscopipe 7000/8000 materials. These socket fusion procedures are qualified in accordance with 49 CFR Part 192. This procedure is applicable to socket fusion of ½" CTS through 2" IPS.

2. SOCKET FUSION PARAMETERS

When making socket fusions the following parameters shall be followed.

Table 1 Socket Fusion Parameters

Heater Face Surface Temperature	Minimum 490 °F - Maximum 510 °F

3. COLD OR INCLEMENT WEATHER CONSIDERATIONS

In cold weather (ambient temperatures below 40 ºF) and in inclement weather (especially in windy conditions), the fusion operation shall be shielded to avoid precipitation or blowing snow and excessive heat loss from the wind.

To ensure the proper heating tool temperature is maintained the heating tool should be stored in an insulated container to prevent excessive heat loss. Sheltering the fusion area from the wind or using a catalytic heater to warm the pipe should be considered. Do not increase the heater temperature to compensate for cold conditions.

Remove all frost, snow or ice from the outer diameter (OD) and inner diameter (ID) of the pipe and fitting to be joined. All surfaces shall be clean and dry prior to fusing.

4. MARKERS

Markings on the pipe shall be made with a non-petroleum based marker as listed below.

a. Any brand of permanent type marker (e.g., Sharpie, Marks-A-Lot & Magic Marker).
b. Any brand of fast drying paint pens (e.g., Pentel and Faber Castell).

Grease pens are petroleum based and shall not be used.

5. FUSION

Before starting the joining process below, clean the pipe surface with clean water and a cloth to remove any dirt and contaminants. Approved alcohol wipes may also be used for this step. When cleaning dirt or mud from the pipe surface ***ONLY*** use clean water. When using clean water in freezing temperatures, follow up by using an approved alcohol wipe to remove any ice film that may have formed. ***NEVER*** use leak detecting solution, detergents, solvents, etc., to clean pipe for fusion.

If at any point in the fusion process the fusion surfaces become contaminated stop and re-start the process from the beginning.

5.1 Preparation

Verify heating temperature is within the specified temperature range of 490°F (minimum) to 510°F (maximum). A pyrometer or other surface temperature-measuring device should be used prior to the first fusion of the day and any time power is interrupted to a heating tool to insure proper temperature of the heating tool face. Temperature indicating crayons shall not be used to check surface temperature of fusion tools. The internal thermometer can only be used as a general indicator, because there is some heat loss from internal to external surfaces. In order to obtain a proper melt, a uniform temperature must be maintained across the heating surface. All points on both heating surfaces where the heating surfaces will contact the pipe and fitting shall be within the minimum and maximum temperatures. Heating tool surfaces shall be clean, free from damage and properly coated with a non-stick coating by the manufacturer.

Cut the pipe ends squarely, and clean the pipe end and fitting, both inside and out with a clean, dry, lint-free cloth. Do not touch the cleaned surfaces with your hand.

Chamfer the outside edge of the pipe end slightly with a chamfering tool. The pipe shall be free of debris and burrs.

Place the cold ring on the pipe as determined by the depth gauge. Place the depth gauge on the chamfered end of the pipe. Clamp the cold ring immediately behind the depth gauge.

When joining coiled pipe, create an S-curve at the socket joint to relieve stress.

5.2 Heating

Review the recommended heating times in Table 2. The heating time begins after the pipe end and fitting are seated firmly on the heating face.

Insert the fitting onto the male heating face. The fitting shall be held against the back surface of the male heating face.

Insert the pipe into the female heating face. The female socket heating face shall be against the cold ring clamp.

Hold the pipe and fitting in place against the heater faces for the recommended heating times as shown in Table 2

Table 2 Socket Fusion Time Cycles

PIPE SIZE	**MDPE 2406/2708**		**HDPE 3408/3608/4710**	
	Heating Times (seconds)	Cooling Times (seconds)	Heating Times (seconds)	Cooling Times (seconds)
½" CTS	6 – 7	30	6 – 10	30
¾" CTS	6 – 7	30	6 – 10	30
1" CTS	9 – 10	30	9 – 16	30
¾" IPS	8 – 10	30	8 – 14	30
1" IPS	10 – 12	30	15 – 17	30
1 ¼" IPS	12 – 14	45	18 - 21	60
2" IPS	16 - 19	45	24 - 28	60

5.3 Fusion and Cooling

At the end of the heating time, simultaneously remove the pipe end and fitting straight out from the tool using a snap action. Do not torque or twist the pipe or fitting during removal.

A quick inspection shall be made of the melt pattern on the pipe end and fitting socket. If there is evidence of an incomplete melt pattern, do not continue with the fusion procedure.

Immediately insert the pipe straight into the socket of the fitting so that the cold ring is flush against the end of the socket fitting. While cooling, pressure shall be maintained on the fusion per the recommended cooling time shown in Table 2.

Allow the joint to cool an additional five (5) minutes before removing the cold ring. An additional ten (10) minutes of cooling time is recommended before exposing the joint to any type of stress (i.e., burial or testing).

5.4 Visual Inspection

Visually inspect the weld. A complete impression of the cold ring clamp shall be visible in the melt pattern at the end of the socket. There shall be no gaps, voids or un-bonded areas. The pipe and fitting shall be in good axial alignment. If the joint appears to be mitered, cut it out and re-fuse a new fitting. Photographs of acceptable and unacceptable socket fusions are shown in Section 7.

5.5 Operator Identification

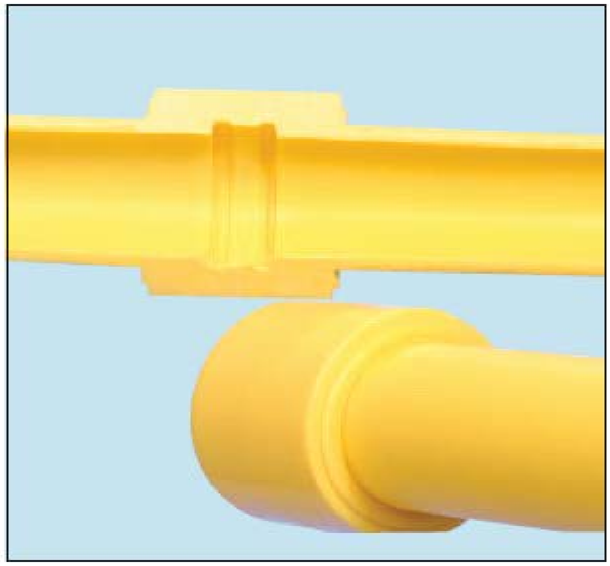
When fusing plastic pipe or fittings, print the date the fusion was made and the employee/contractor ID, e.g. NiSource employee I.D. number, of the person performing the fusion on the pipe.

6. UPONOR (DUPONT) TEE REPAIR KIT

The Uponor (Dupont) Tee Repair Kit, manufactured by US Poly, is permitted and shall be installed in accordance with the manufacturer’s instructions when selected as a repair method for Uponor (Dupont) Aldyl “A” service tees.

7. PHOTOGRAPHS OF ACCEPTABLE AND UNACCEPTABLE SOCKET FUSIONS

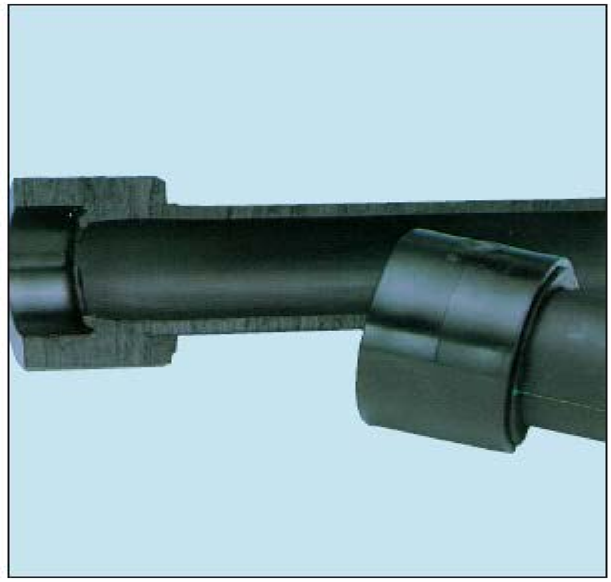
ACCEPTABLE FUSIONS



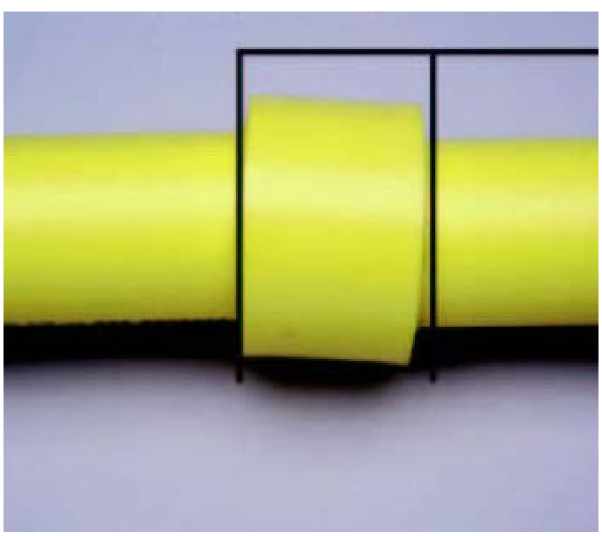
Proper alignment and stab depth. Melt bead flattened due to cold ring. No gaps or voids.

UNACCEPTABLE FUSIONS

Short stab depth caused by failure to use a depth gauge.



Excessive stab depth caused by failure to use a cold ring.



Mitered joint.

Effective Date: 01/01/2013	Maintenance of Fusion Equipment	Standard Number: **GS 1316.010(CG)** P&P 644-10
Supersedes: 01/22/2003		Page 1 of 6

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE None

1. GENERAL

Quality of fusions is affected by the condition of equipment and accessories used to make the joint. Equipment must operate properly and be free of any residue that could contaminate the fusion joint.

The following are maintenance requirements that apply to all fusion equipment approved for use by the Company other than electrofusion units (see Section 6). The condition of the equipment shall be checked before each use.

2. RESPONSIBILITY

The fusion operator is responsible to ensure that the fusion equipment is in good condition prior to use. Any fusion equipment found to be defective or in need of repair shall be repaired prior to use.

3. JOINER UNITS

The following maintenance requirements apply to all joiner units:

a. Remove dirt and oily residue from guide rods and apply a few drops of motor oil to the guide rod surfaces, as necessary.

b. Occasionally wash hand knob thrust bearings in kerosene or solvent and lubricate with motor oil. Replace if the bearing does not rotate.

c. Occasionally add a few drops of motor oil to pivot pins.

d. Before each use check nuts and bolts for tightness and make sure snap rings and spring clips are in place.

3.1 Non-Hydraulic Units

a. On McElroy units, fill the guide rod bushing oil reservoir with a few drops of motor oil. This is done by removing the handle yoke shoulder screw from the end of the movable jaw, putting a few drops of oil into the threaded screw cavity and replacing the screw. Wipe excess oil from the jaw.

b. Replace guide rod bushings if worn.

c. Replace guide rods if damaged.

3.2 Hydraulic Units

a. Check the level of the hydraulic oil in the reservoir. Hydraulic oil and filter should be changed once a year. A non-foaming high grade hydraulic oil must be used.

Note: Spent hydraulic oil and filters shall be collected for disposal in accordance with environmental regulations.

b. Cart wheels should be cleaned and re-packed with grease once a year.

c. Check power cord to pump motor. Replace if worn.

d. Check gauge to verify reading is zero when unit is not running.

4. FACER ASSEMBLY

The following maintenance requirements apply to the facer assembly:

a. Check power cord and plug. Replace if worn.

b. Check facer blades for sharpness. Replace if dull.

c. Check fixed and movable guide rod bushings. Replace if worn.

d. Check for play in blade holder. Replace bushing if worn.

e. Facer should be disassembled and packed with high temperature grease every six (6) months. Make sure facer screws are tightened securely after re-assembly.

5. HEATING IRONS AND ADAPTERS

The following maintenance requirements apply to the heating iron and adapter:

a. Check power cord and plug. Replace if worn.

b. Check thermometer. Replace if damaged.

c. Clean the surface of coated heating iron body and adapters after each use with a clean non-synthetic rag. Excess residue (black deposits) should be removed before each use. This can be done by allowing the heater to cool then buffing the surface softly with a “Scotch-brite” pad (Material Catalog, Groupid M-33). This will not remove the discoloration, only the build-up.

Dirt build-up between heating body and adapter, or loose screws will not allow correct heat transfer.

d. Check coated surfaces of heater and adapter for damage.

e. A pyrometer should be used prior to the first fusion of the day to ensure proper temperature of the heating tool face. Check more often if operational problems are suspected.

Irons which do not maintain a temperature of 500°F ± 10°F shall be adjusted or repaired prior to use.

Temperature adjustment shall be made only by an employee specifically trained to make the adjustment.

6. ELECTROFUSION ACCESSORIES

6.1 Electrofusion Units

Electrofusion units shall be maintained according to manufacturer's instructions. When the unit malfunctions, the manufacturer's representative shall be contacted. A failure report shall be submitted according to GS 1652.010 “Investigation of Failures.”

6.2 Scrapers

6.2.1 Blade Assembly

Replacement blades are available to fit each size of main scraper. Each blade has two scraping edges.

When the main scraper starts producing strings of material instead of a full ribbon, it is time to replace the scraping edge. A new blade should be installed, if both edges of a blade have been used.

Effective Date: 01/01/2013	Maintenance of Fusion Equipment	Standard Number: **GS 1316.010(CG)** P&P 644-10
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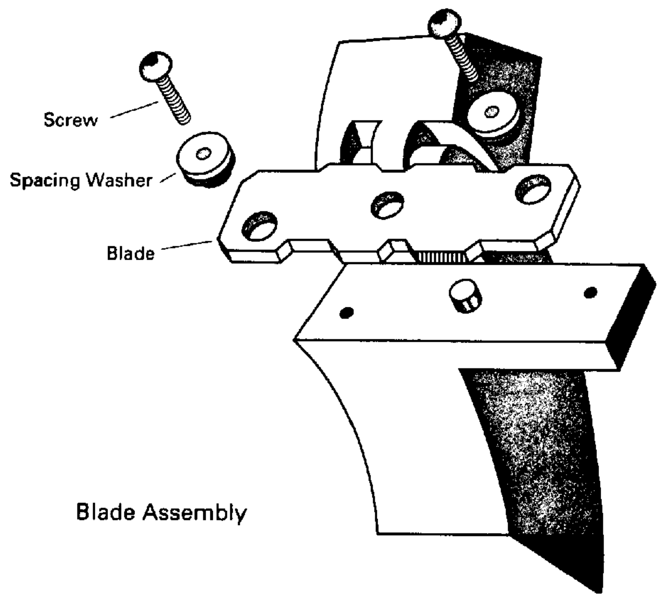


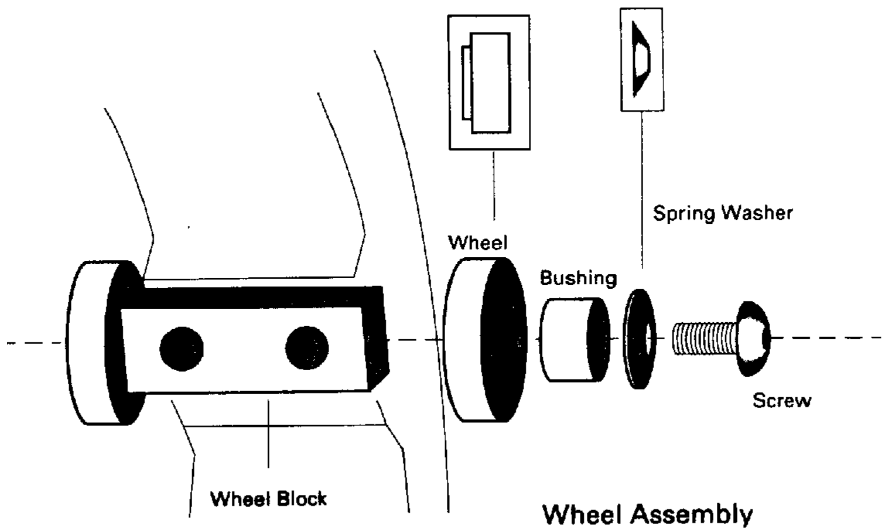
The blade should be assembled in the scraper frame as shown. The two mounting screw holes are offset to prevent inserting the blade the wrong way.

When tightening the screws, be careful not to over tighten. Threads in the aluminum body can be damaged.

Lock tight with a 4.0mm (5/32 inch) hex wrench. When tightened, the spacing washer is designed to allow the blade to pivot on the center pin. The blade should move freely on 1 1/4 inch and 2 inch scrapers, but will be held captive on other sizes by the conical washers.

6.2.2 Wheel Assembly

Dust and grit in the wheel bushing can cause a wheel to seize on its bushing. If this happens, remove the wheel from the wheel block and tap out the center bushing. Clean any deposits from the outside of the bushing and inside the wheel. Reassemble as described here. If a wheel assembly needs to be replaced, wheel kits are available and should be assembled as shown:



a. Apply a thin film of heavy grease to the outer surface of the bushing.

b. Assemble the components as shown. The wheel should be assembled with the shoulder against the wheel block, the conical washer with the concave side against the wheel.

c. Tighten the screw with a standard 4.0mm (5/32 inch) hex wrench.

d. Check that the wheel rotates freely after assembly.

6.2.3 Latch Hook and Handle Assembly

If it becomes necessary to replace any components of the latch hook and handle assembly, kits are available for both. To change either assembly, follow these instructions:

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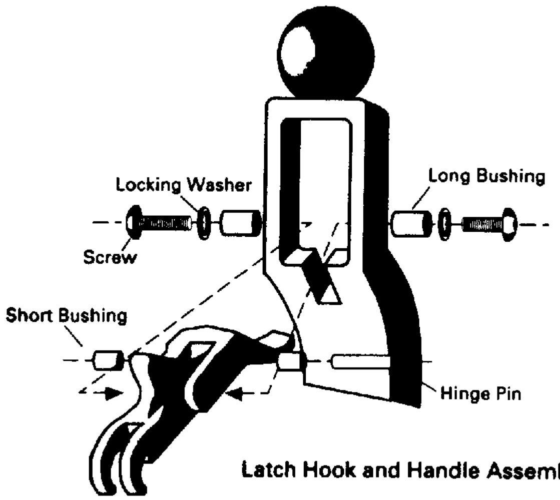

Latch Hook and Handle Assembly

a. Disassemble the latch hook and handle assembly from the scraper body by removing the two hexagon-headed screws.

b. Disassemble the latch hook from the handle by tapping out the hinge pin.

c. Reassemble the hook and handle assembly using new parts as required. The original hinge pin should be reused.

d. Secure the assembly into the scraper frame using the new bushings, screws and lock washers. Tighten screws using a standard 4.0mm (5/32 inch) hex wrench.

e. Check that the assembly moves freely in the scraper body.

7. WMS REPETITIVE TASKS

To assure the periodic maintenance requirements of this procedure are accomplished, it is suggested that a WMS Repetitive Task be established for the following items:

a. Hydraulic Units, annually (Refer to Section 3.2).

b. Facer Assemblies, semi-annually (Refer to Section 4).

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Distribution Operations

Gas Standard

Effective Date: 01/22/2003	Field Inspection of Plastic Fusion Operations	Standard Number: **GS 1318.010(CG)** P&P 644-9
Supersedes: N/A		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE Code of Federal Regulations - Title 49 - Part 192 - §§ 192.273 and 192.287

1. RESPONSIBILITIES

Personnel who inspect plastic fusions on Company owned facilities shall be qualified to join or trained to evaluate acceptability of plastic fusion joints once each calendar year. The fusion operator shall be responsible for the quality of fusion joining workmanship and for the acceptance and rejection of production fusion joints. The Company reserves the right to accept or reject any production joints. The fusion operator shall replace all rejected production joints.

2. FIELD INSPECTION AREAS

Inspectors of contract projects and employee in charge of Company projects shall be responsible for ensuring that the following observations, inspections, and conditions necessary for satisfactory fusion joining are met:

a. Suitability of equipment - fusion equipment shall have the capability to perform the fusion operations set forth in GS 1302.010 "Butt Fusion Joining," GS 1304.010 "Electrofusion Joining," and GS 1308.010 "Socket Fusion Joining."

b. Equipment maintenance - equipment shall be properly maintained in accordance with GS 1316.010(CG) "Maintenance of Fusion Equipment."

   The following are fusion equipment conditions that affect fusion quality and shall be repaired before the equipment is used:

   1. side-play in the moveable jaw bushings
   2. movable jaw that does not move along the guide rods freely
   3. damaged guide rods
   4. play in the facer blade holder
   5. a facer that wobbles on the guide rods
   6. dull facer blades
   7. damage or contaminated heater surfaces
   8. electrofusion scraper not rotating or the blade not removing a complete

continuous ribbon

c. Field working conditions - shall determine if the weather conditions, i.e. rain, wind, or extreme low temperature, will have any adverse effect on the fusion joints. If so, appropriate measures shall be taken to eliminate the conditions or fusion operations shall be suspended.

d. Fusion joiner qualification - shall be in accordance with GS 1301.010 “Plastic Pipe and Mechanical Joining Qualification of Personnel.”

Assigned inspectors of contract projects shall not permit contractor personnel who do not have a valid identification card to make plastic fusions on Company facilities.

Note: Any identification card retained because of unacceptable production joint(s) is to be forwarded to Technical Training along with the reason for pulling the identification card. Where practical, the unacceptable production joint should be forwarded along with the card.

e. Observation of fusion techniques of the fusion joiners shall be performed to determine whether proper fusion procedure is being followed. Failure of the fusion joiner to follow proper fusion joining procedure is cause for the joint to be cut out.

f. Visual inspection of fusion joints shall be accomplished to ensure that fusion joints have the characteristics of an acceptable joint in accordance with GS 1302.010 “Butt Fusion Joining,” GS 1304.010 “Electrofusion Joining,” and GS 1308.010 “Socket Fusion Joining.” Any joint of questionable appearance shall be cut out.

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Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Mechanical Coupling Connections	Standard Number: GS 1320.010
Supersedes: 01/01/2014		Page 1 of 9

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Manufacturer’s instructions shall be used when installing mechanical couplings. Refer to the Gas Distribution Standards page of MySource, within the “Materials & Equipment” Section, Sub-Category “Instructions,” for mechanical fitting instructions for specific fittings.

Mechanical couplings should not be used except where the confines of the excavation or safety considerations dictate their use over welding or plastic fusion.

Existing mechanical couplings, when exposed, should be evaluated for pullout potential. Adequate mitigating measures (e.g., strapping, blocking, anchoring) should be employed if the potential for pullout is apparent.

2. MECHANICAL COUPLING CATAGORIES

Mechanical couplings are divided into two categories as follows.

2.1 Seal Only

“Seal Only” couplings have no provision in design or manufacture to resist longitudinal pull-out forces, and the end user is responsible for providing adequate pipe anchorage with the restraint offered by soil or other means.

2.2 Seal and Restraint

“Seal and Restraint” couplings have provisions for pull-out resistance to a specified rating for joining steel pipe or a category for joining plastic pipe as published by the manufacturer.

3. ASSEMBLY INSTRUCTIONS

Mechanical couplings shall not be disassembled unless permitted by the manufacturer’s installation instructions. When permitted to disassemble, care shall be exercised to ensure proper reassembly.

The assembly of mechanical fittings shall be according to the manufacturer’s instructions.

4. POST INSTALLATION INSTRUCTIONS

After installation, test for leakage in accordance with applicable pressure testing gas standards. Refer to GS 1500.010, GS 1500.010(MA), or GS 1500.010(OH) "Pressure Testing" for additional guidance.

4.1 Application of Corrosion Control or Cathodic Protection

Consult with local corrosion personnel regarding the installation of a continuity bond wire (or strap) across a non-insulating type coupling (refer to GS 1420.540 "Installation of Bonds" for additional guidance).

For metallic couplings installed on steel or wrought iron, corrosion control shall be provided by coating the exposed piping and patch-coating or coating the coupling. Refer to GS 1420.040 "Coating Methods for Girth Welds, Fittings, Risers, & Other Below Ground Appurtenances" and GS 1420.510 "Installation of Galvanic Anodes" for additional guidance.

For metallic couplings installed between two plastic pipe segments, cathodic protection shall be provided for the coupling by patch-coating or coating the coupling. Refer to GS 1420.040 "Coating Methods for Girth Welds, Fittings, Risers, & Other Below Ground Appurtenances" and GS 1420.510 "Installation of Galvanic Anodes" for additional guidance.

4.2 Backfillling

Voids under pipe shall be filled and compacted with a suitable compactable backfill (e.g., sand, sand-gravel mixture, flowable backfill) to minimize secondary stresses prior to backfilling the remaining tie-in hole or trench. For additional guidance, refer to the applicable GS 3010.050 "Installation of Pipe in a Ditch."

5. STRAPPING, BLOCKING, AND/OR ANCHORING MECHANICAL COUPLING CONNECTIONS

Strapping, blocking, and/or anchoring may be required of mechanical coupling connections where the potential for pipeline movement exists. The effect of forces due to change in direction, dead-ending, soil movement, pressurizing/depressurizing, separating the pipeline, or pipe contraction could cause joint failure from pipe pullout on "Seal Only" type mechanical couplings or dead end caps and must be mitigated.

Strapping is preferred over blocking on steel pipe. Where straps are used on insulated connections, they shall be insulating type straps. See Exhibit A. When strapping is not practical, such as is the case with cast iron or plastic pipe, the mechanical coupling and pipe shall be blocked or anchored to prevent movement. Anchoring, when appropriately designed, provides support to additional mechanical couplings in the pipeline, not just those in the immediate work area.

Whenever a "Seal Only" coupling is exposed, it shall be strapped according to Section 5.2, blocked according to Section 5.3, and/or anchored according to Section 5.4.

In addition, the following guidelines should be considered when exposing pipelines joined by "Seal Only" couplings.

a. Perform a supplemental leakage survey prior to exposing the coupled pipeline to determine if any existing couplings are leaking.
b. Consult with Engineering to verify if it is possible to temporarily take the pipeline out of service.
c. If it is not possible to take the pipeline out of service, consult with Engineering to determine if the pipeline pressure can be reduced as low as possible.
d. Determine if the proposed work makes it necessary to identify additional couplings adjacent to the work area (e.g., planned separation of a coupled pipeline, pressurizing or depressurizing a coupled pipeline).
e. Limit the extent of pipeline exposure at any one time to prevent the destabilization of the pipeline.
f. Support stopple fittings and related appurtenances to prevent their weight from destabilizing the pipeline.
g. Installation of a controlled density backfill (e.g., Flash Fill®) may be appropriate in lieu of backfilled soil where proper compaction is necessary for pipe support.
h. Perform a supplemental leakage survey after construction and/or maintenance activities are completed to determine if activities caused coupling pull-out.

5.1 Application of Corrosion Control Materials

Before the installation of concrete or a controlled density backfill against a steel pipeline, the pipe must be coated, wrapped, or otherwise protected from corrosion and damage. Contact local corrosion personnel for corrosion control recommendations.

5.2 Strapping

When mechanical couplings are strapped, Table 1 prescribes the number and specifications for the straps.

Table 1

Pipe Diameter	Strap Width	Minimum Strap Thickness	Minimum Number of Straps	Minimum Fillet Weld Length
1 ¼" or less	½"	0.125"	2	1"
2"	1"	0.125"	2	1"
3"	1"	0.125"	2	1"
4"	1"	0.125"	2	1"
6"	1"	0.156"	2	1"
8"	1"	0.172"	2	1 ½"
10"	1"	0.188"	3	1 ½"
12"	1"	0.203"	4	1 ½"
16"	1 ½"	0.219"	4	2 ½"
20"	2"	0.250"	4	3"
24"	2"	0.250"	5	3 ½"

Straps, when installed, shall:

a. have a minimum yield strength of 25,000 psi,

b. fit snugly against the mechanical fitting (except for insulating straps),

c. be evenly spaced around the pipe,

d. be fillet welded across each end and for the minimum specified distance down each side of strap (see Table 1 above), and

e. be coated.

For dead-end mechanical couplings, it is permissible to wrap one strap around the end of the fitting and/or bull plug for each two straps required. See Exhibit A.

5.3 Blocking

Strapping is preferred over blocking on steel pipe. However, when strapping is not practical, such as when a dead end coupling is used on cast iron pipe, blocking is an acceptable alternative. Non-decaying material shall be used when blocking a mechanical fitting in place unless it is for a temporary installation, such as during a test. Blocking should be located or positioned so that backfilling will not move or destroy the desired effect. An example of blocking is shown in Exhibit B.

5.4 Anchoring

Anchoring is the process of installing support to the pipeline to prevent movement as the result of imposed force. The most commonly engineered method is to place concrete between the pipeline and undisturbed soil along the axis of the imposed force. Additional concrete may be placed above and below the pipe to provide additional support. Temporary anchoring (e.g., during pressure testing) may be done with bags of sand or grout placed securely around a change in direction or dead end.

Anchoring is most often necessary where existing coupled pipelines with “Seal Only” joints are exposed. When an existing coupled pipeline has been adequately buried in a stable location, soil often provides stability to hold the pipeline in place. When the coupled pipeline is exposed or has minimal or loose backfill, there is very little support to restrict movement of the line. Concrete anchoring to counteract the forces resulting from depressurizing and pressurizing is not typically required for coupled pipelines operating at pressures of 10 psig or less, unless other destabilizing conditions exist (e.g., unstable soil).

An anchor must be poured so that it rests against undisturbed soil so that the force can be adequately distributed to the undisturbed soil. Anchoring will not be effective in saturated, unconsolidated (e.g., mucky, swampy) soil.

It is common to construct concrete anchors around exposed changes in direction, which can be designed to resist longitudinal forces expected from pressurizing and depressurizing. An example of a concrete anchor along an exposed change in direction is shown in Figure 1. If there are no exposed changes in direction to anchor, an anchor can be fabricated according to Figure 2 below.

A combination of strapping, blocking, and/or anchoring may be optimal when a new pipeline is tied into an existing pipeline that had been joined by mechanical couplings. Contact local Field Engineering personnel for assistance in designing a concrete anchor and/or developing a plan to strap, block, and/or anchor (refer to GS 2220.010 “Concrete Anchor Design”).

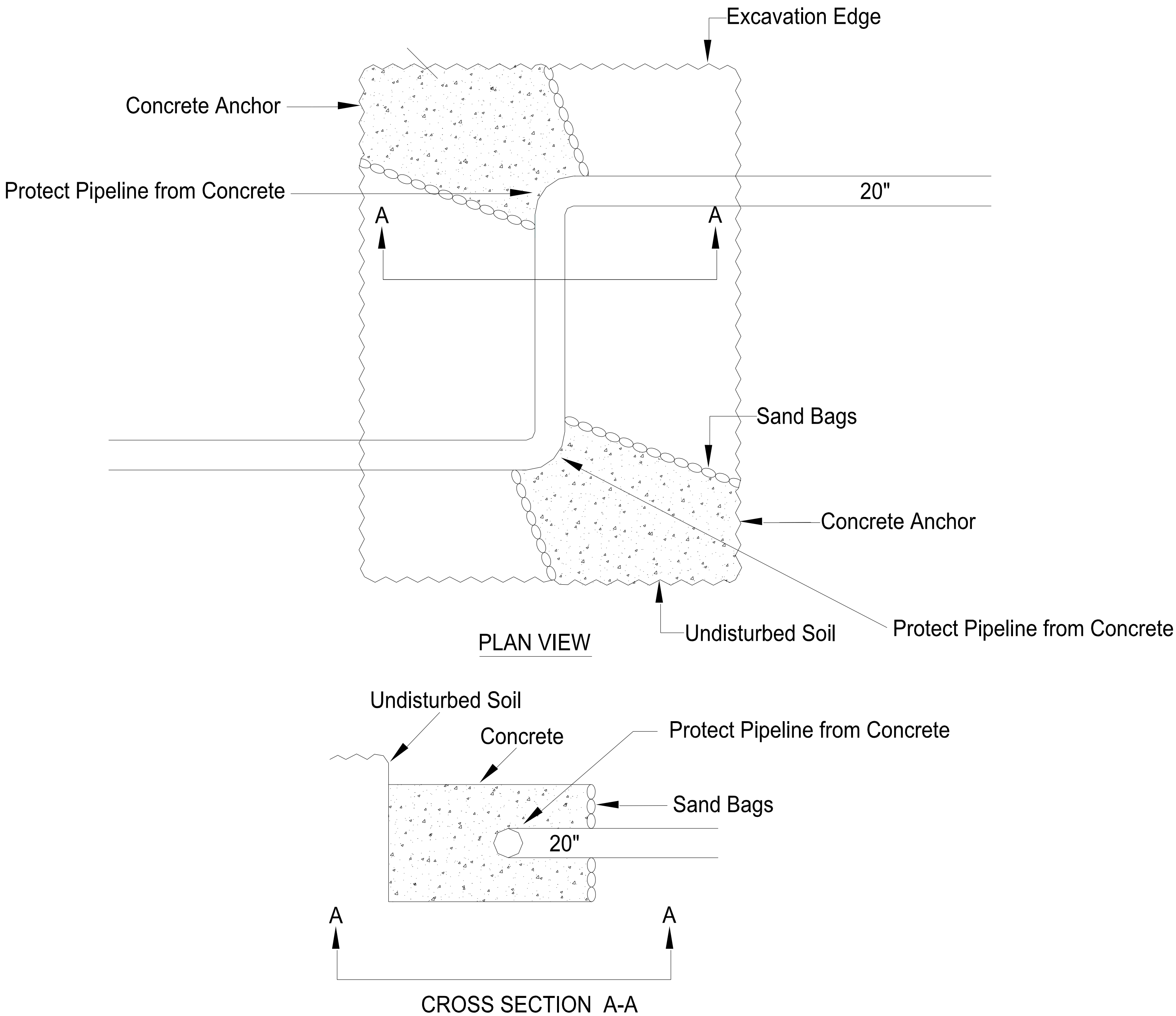

Figure 1: Concrete Anchor Design for an Exposed Change in Direction

NiSource
Distribution Operations

Gas Standard

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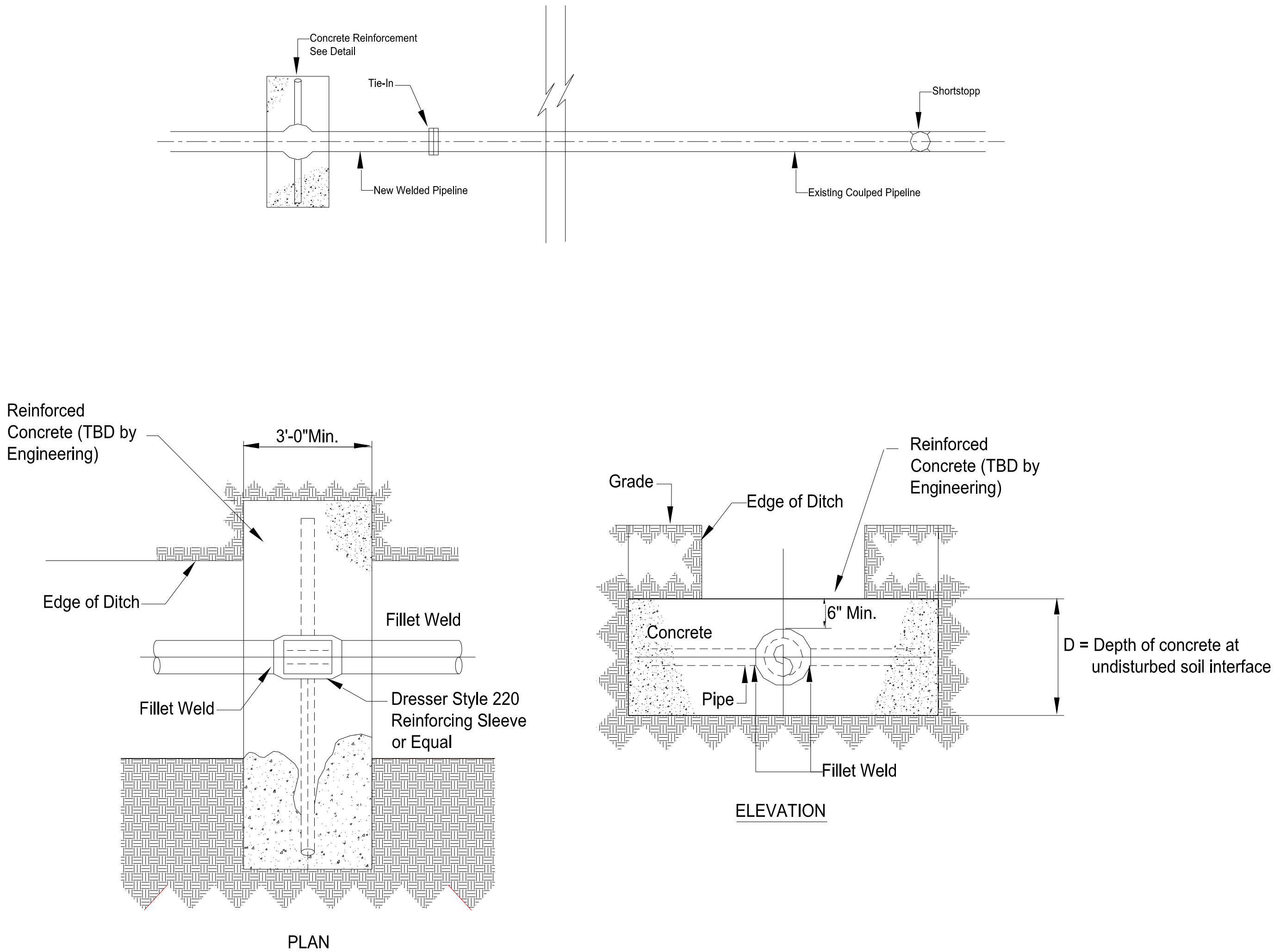
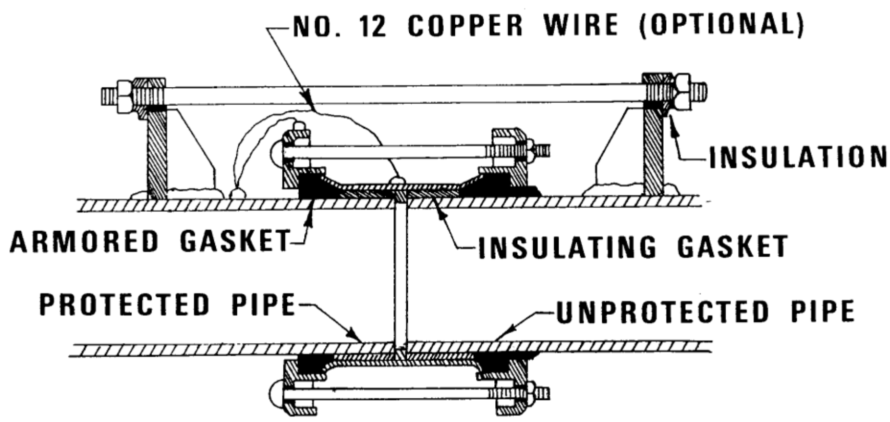
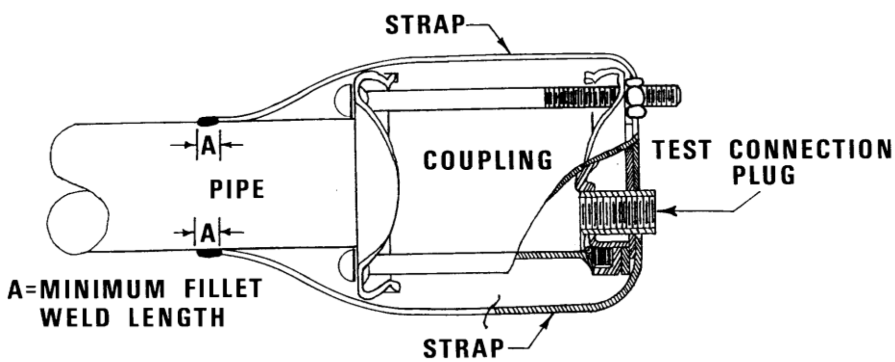


Figure 2: Concrete Anchor Design for a Straight Section of Pipeline

EXHIBIT A

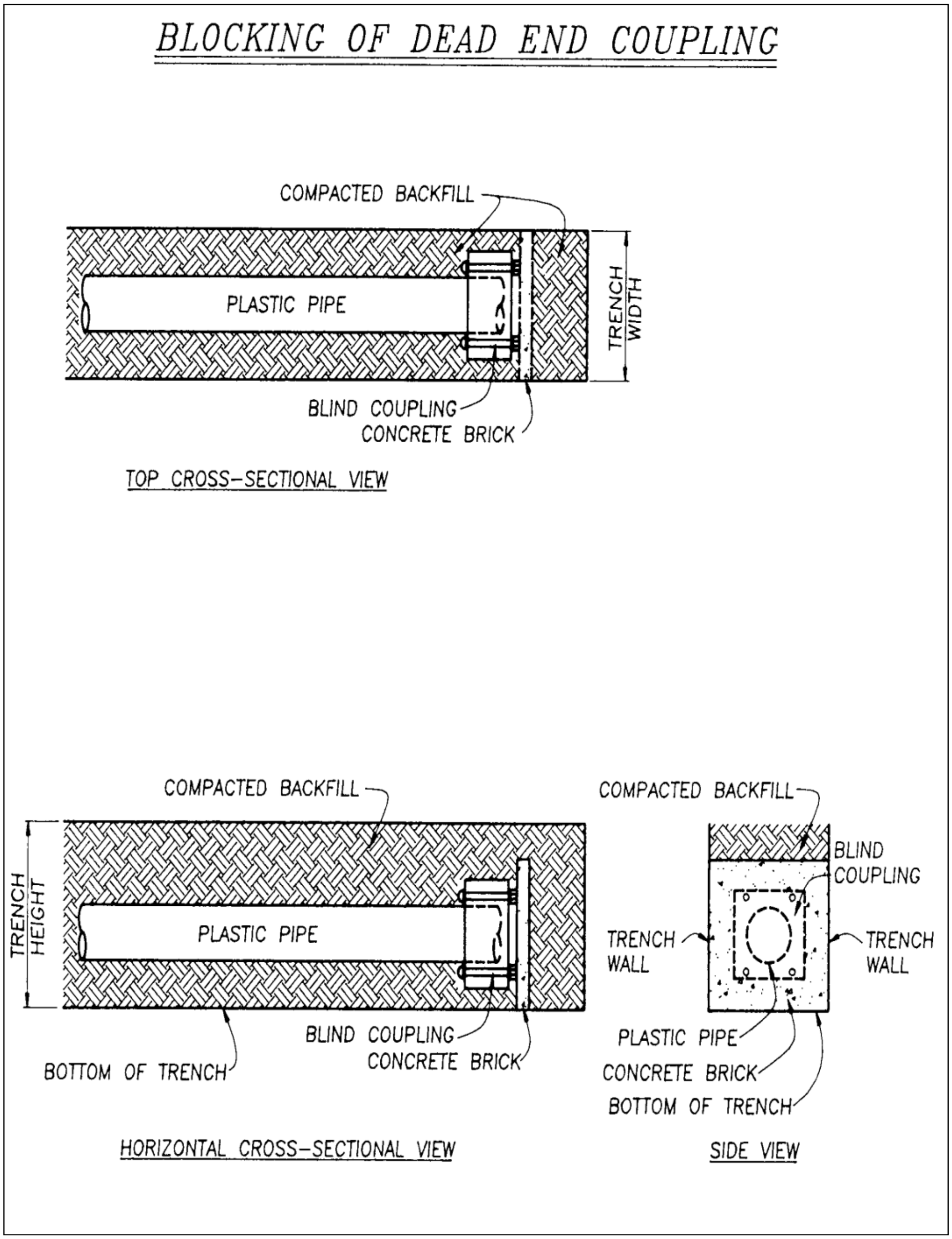


STRAPPING INSULATING COUPLING



STRAPPING DEAD END COUPLINGS

EXHIBIT B


BLOCKING OF DEAD END COUPLING
COMPACTED BACKFILL
PLASTIC PIPE
TRENCH WIDTH
BLIND COUPLING
CONCRETE BRICK
TOP CROSS-SECTIONAL VIEW
COMPACTED BACKFILL
TRENCH HEIGHT
PLASTIC PIPE
BLIND COUPLING
CONCRETE BRICK
BOTTOM OF TRENCH
HORIZONTAL CROSS-SECTIONAL VIEW
COMPACTED BACKFILL
BLIND COUPLING
TRENCH WALL
TRENCH WALL
PLASTIC PIPE
CONCRETE BRICK
BOTTOM OF TRENCH
SIDE VIEW

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Flange Connections	Standard Number: **GS 1323.010**
Supersedes: NA		Page 1 of 10

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE Code of Federal Regulations - Title 49 -Part 192 - Subpart D - § 192.147
ANSI B16.5, ANSI B16.24 and MSS SP-44

1. APPLICATION AND LIMITATIONS

The primary pressure rating for steel pipe flanges and flanged fittings is set forth in ANSI B16.5, "Steel Pipe Flanges and Flanged Fittings." The maximum allowable operating pressures (MAOP) for flange connections are:

ANSI Class	MAOP
Steel	
150 psig	285 psig
300 psig	740 psig
600 psig	1480 psig
Cast-Iron*	
125 psig	175 psig
250 psig	400 psig
Ductile-Iron*	
250 psig	575 psig

* Cast (Ductile) Iron Flanges are common on regulator bodies and valves. The MAOP's stated in above table are for those most commonly encountered. However, pressure ratings (MAOP's) on regulator and valve bodies may differ from those shown in the table; in such cases the lower pressure rating shall apply.

The raised face on a cast iron flange shall not be removed.

The burial of valves or other flanged fittings with cast-iron or ductile iron ANSI Class 250 flanges and ANSI Class 125 cast-iron flanges is prohibited.

Each flange on a flanged joint in cast iron-pipe must conform in dimensions, drilling, face and gasket design to ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

Exhibit A can provide guidance in identifying the flange rating.

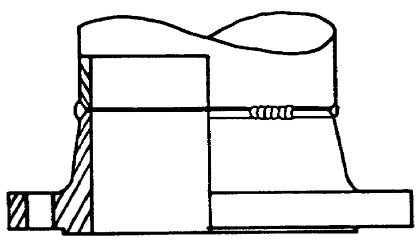
2. TYPES OF FLANGES

There are a variety of flanges with different applications.

2.1 Weld Neck Flanges

Weld neck flanges are distinguished from other types by their tapered hub and gradual transition of thickness in the region of the butt weld joining them to the pipe. The long tapered hub provides an important reinforcement of the flange proper from the stand point of strength. This type of flange is preferred for severe service conditions such as high pressure, sub-zero temperature, or extreme or fluctuating loading conditions.

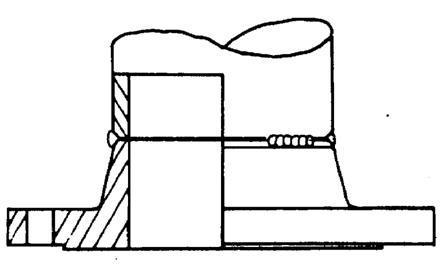
The bore of welding neck flanges should correspond to the inside diameter of the pipe used. If a difference in wall thickness between the pipe and the flange exists, refer to the applicable welding procedures for permissible mismatches and corrective measures.



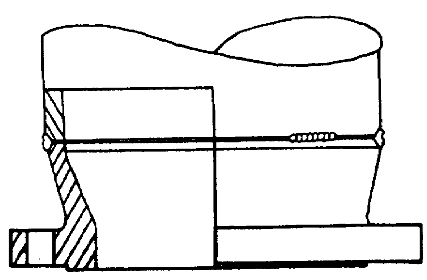
WELD NECK FLANGE

2.2 Weld Neck Reducing and Expander Flanges

When a pipe size change is needed at a flanged connection, the transition in size is generally accomplished by use of a welding reducer or expander. When space is limited, a weld neck reducing or expander flange can be used.



WELD NECK REDUCING FLANGE

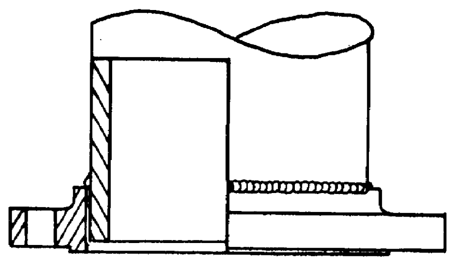


WELD NECK EXPANDER FLANGE

2.3 Slip-On Flanges

Slip-on flanges are not recommended for use over 4 inches NPS or in a cyclic stress environment and are limited to:

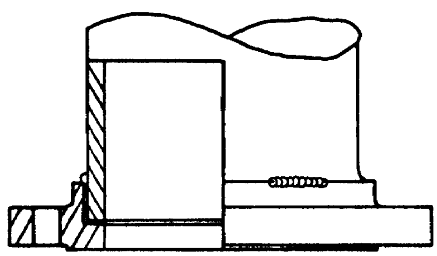
a 720 psig maximum allowable operating pressure.



SLIP-ON FLANGE

2.4 Socket Welded Flanges

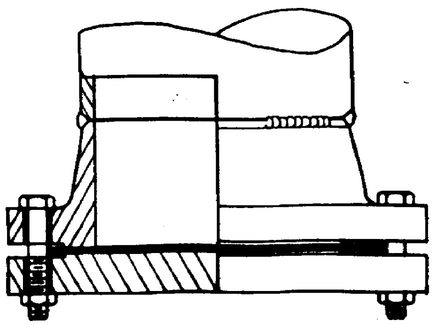
Socket weld flanges shall not be used above 3 inches NPS. In compressor stations, socket weld flanges shall not be used above 2 inches NPS. Socket weld flanges shall be ANSI Class 600 or heavier.



SOCKET WELDED FLANGE

2.5 Blind Flanges

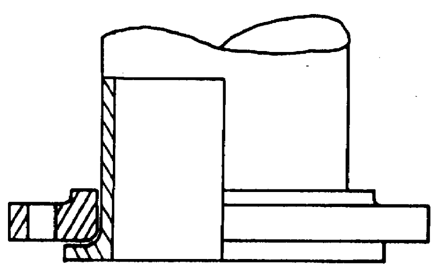
Blind flanges are used to blank off the ends of flanged piping, valves and pressure vessel openings. Fabricated or “plate” flanges shall not be used.



BLIND FLANGE

2.6 Lap Joint Flanges (Van Stone)

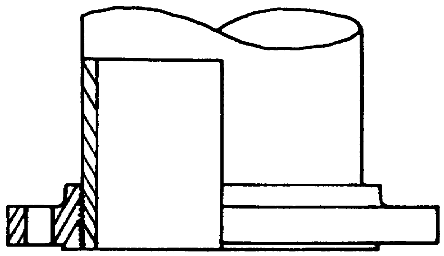
Lap joint flanges may be useful when frequent dismantling for inspection and cleaning is necessary and where the ability to swivel flanges in order to align bolt holes is desirable. Lap joint flanges are prohibited for below ground use and where vibration, lateral movement or severe stress is anticipated.



LAP JOINT FLANGE

2.7 Screw Flanges

The use of screw flanges is not recommended. However, where screwed flanges are used, at least Schedule 40 (Standard Weight) pipe must be used to offset the loss of strength due to threads. Screwed flanges shall be steel and are confined to above ground applications only.



SCREW FLANGE

3. REUSE OF FLANGES AND FLANGED FITTINGS

Flanges and flanged fittings may be reclaimed for reuse. See Section 4.7 "Reuse/Reclamation Practices for Weld Flanges and Fittings" in the Company Welding Manual.

4. FLANGES AND GASKET COMBINATIONS

The following table reflects the flange and gasket combinations that can be used.

FLANGE COMBINATION	MAOP	FLANGE FACING	BOLT/STUD & NUT	GASKET
125 CI X 125 CI	175	FLAT X FLAT	A-307. GRADE B	RING
125 CI X 150 STEEL	175	FLAT X FLAT	A-307. GRADE B	RING
150 STEEL X 150 STEEL	285	RAISED X FLAT	A-307. GRADE B	RING
150 STEEL X 150 STEEL	285	RAISED X RAISED	A-307. GRADE B	RING
250 CI X 250 CI	400	RAISED X RAISED	A-307. GRADE B	RING
250 CI X 300 STEEL	500	RAISED X RAISED	A-307. GRADE B	RING
300 STEEL X 300 STEEL	740	RAISED X RAISED	A-307. GRADE B or A-193. GRADE B7 BOLT A-194. GRADE 2H NUT	RING
600 STEEL X 600 STEEL	1480	RAISED X RAISED	A-307. GRADE B A-194. GRADE 2H NUT	RING

If encountered, an ANSI Class 300 flat face steel flange being connected to a raised face ANSI Class 250 cast-iron flange would require a ring gasket.

5. BOLTING

Bolting must produce the necessary compression to deform the gasket material and be capable of maintaining compressive loading while resisting all imposed forces, such as pressure, weight, expansion and contraction and soil movement. To accomplish this, the bolts must be adequately and uniformly tightened.

Instructions for proper bolting are as follows:

a. Clean bolt and nut threads. Remove any burrs or chips. Do not use bolts with damaged threads. Repair the damage or dispose of the bolt.

b. Lubricate threads. It is difficult to obtain the required bolt tightness without applying a thread lubricant. With lubrication, approximately twice the tightness can be obtained.

c. Assemble the bolts hand-tight around the flanges; then, wrench them up lightly, alternately tightening diametrically opposite bolts until all the bolts have been lightly tightened. (Gasket begins to be depressed.) Next, go around the bolting circle and successively tighten each bolt. Repeat this until all bolts have been completely secured.

   Note: At least two full threads on the bolt or stud bolt should extend beyond the nut when the joint has been assembled but at a minimum, the bolt or stud bolt shall extend completely through the nut.

Machine and stud bolts should be obtained from Company warehouses. Machine bolts and nuts purchased from outside sources must be in conformance with ASTM A 307, Grade B. Machine bolts shall be used with cast-iron flanges or a combination of cast iron and steel when ring gaskets are used.

High tensile stud bolts shall be in conformance with ASTM A 193 and the nuts to ASTM A 194, Grade 2H. The stud bolts should have the letters “HT” stamped (or equivalent marking designating high tensile) into the end of the stud. Stud bolts shall not be used with cast-iron flanges when a ring gasket is used. Stud bolts may be used for all pressure classes where steel flanges are used.

6. INSULATION

Prefabricated insulating flange units per CDC Standard Drawing No. S-687, Exhibit B, when used as a below ground electrical insulating method, are ready to weld in the main. The end of the prefabricated insulating flange containing the insulating washers and marked with a yellow dot should be welded to the “unprotected” pipe. Precaution should be taken to assure the completed welding of both ends does not result in stress buildup due to piping misalignment. The shop assembly of prefabricated insulating flanges shall be done under the direction of shop personnel trained by Corrosion personnel.

The use of insulating flange kits to electrically isolate existing below ground or above ground weld neck flanges shall be tested to ensure effective isolation during installation. The use of prefabricated insulating flange units versus the use of field installed insulating flange kits is recommended.

The use of insulating flange kits to insulate above ground flange connections is discouraged. When above ground insulating kits are installed, they must also have a properly installed grounding cell per CDC Standard Drawing No. S-400, Exhibit C.

Ring gaskets shall not be used to insulate flanges.

Other types of insulators may be used in below ground piping in lieu of prefabricated insulating flange units. For additional information refer to GS 1420.530 “Installation of Insulators.”

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Flange Connections	Standard Number: **GS 1323.010**
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EXHIBIT A

	STEEL FLANGES*								
	ANSI CLASS 150, MAOP 285 psig			ANSI CLASS 300, MAOP 740 psig			ANSI CLASS 600, MAOP 1480 psig		
Pipe Diameter (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolt (inches)	Number of Bolt (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolts (inches)	Number of Bolts (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolts (inches)	Number of Bolts (inches)
1	3-1/8	1/2	4	3-1/2	5/8	4	3-1/2	5/8	4
2	4-3/4	5/8	4	5	5/8	8	5	5/8	8
3	6	5/8	4	6-5/8	3/4	8	6-5/8	3/4	8
4	7-1/2	5/8	8	7-7/8	3/4	8	8-1/2	7/8	8
6	9-1/2	3/4	8	10-5/8	3/4	12	11-1/2	1	12
8	11-3/4	3/4	8	13	7/8	12	13-3/4	1-1/8	12
10	14-1/4	7/8	12	15-1/4	1	16	17	1-1/4	16
12	17	7/8	12	17-3/4	1-1/8	16	19/1/4	1-1/4	20

*ANSI Class 400 flanges are not generally stacked or used.

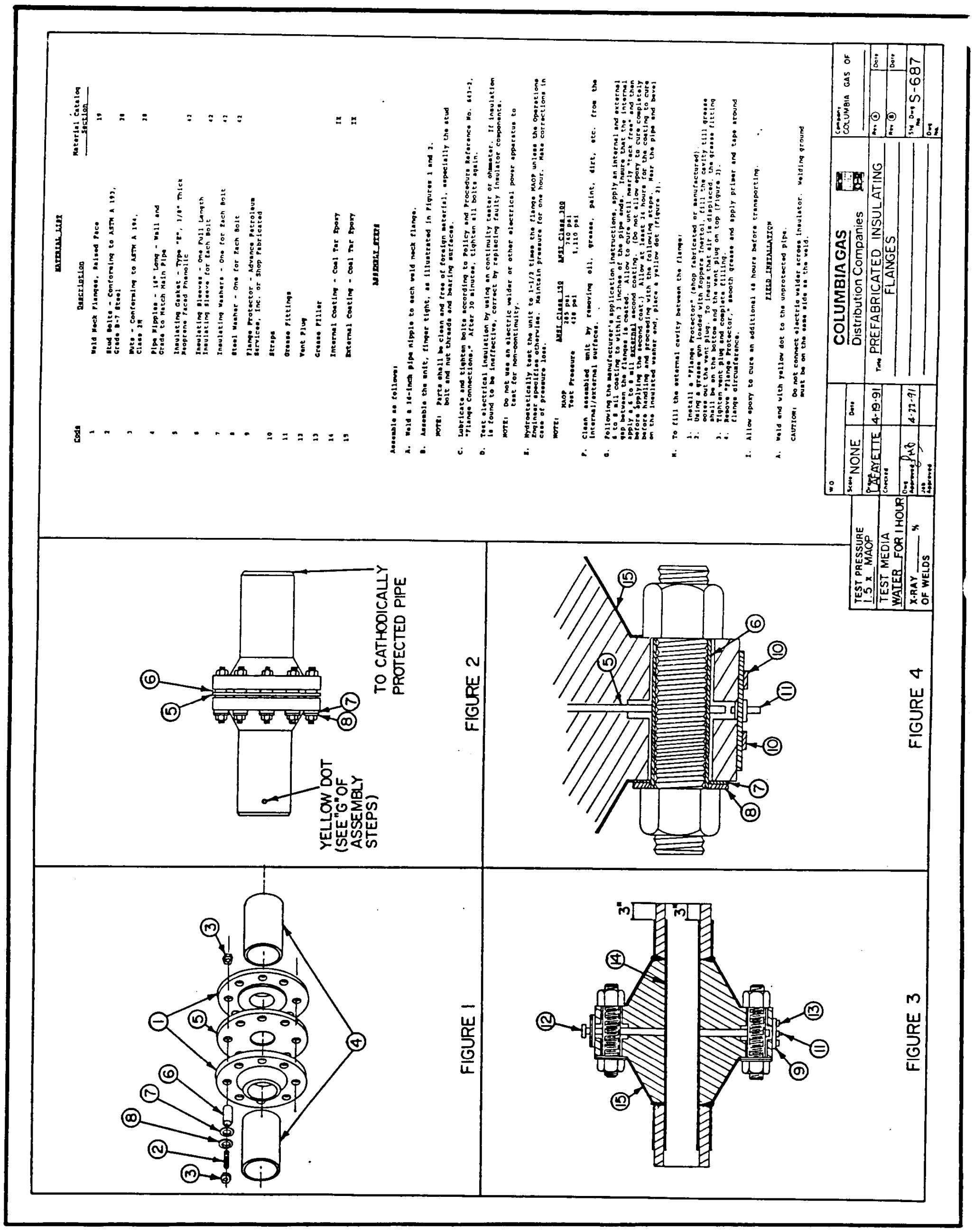
	CAST IRON						DUCTILE IRON		
	ANSI CLASS 125, MAOP 175 psig			ANSI CLASS 250, MAOP 400 psig			ANSI CLASS 250, MAOP 575 psig		
Pipe Diameter (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolts (inches)	Number of Bolts (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolts (inches)	Number of Bolts (inches)	Diameter of Bolt Circle (inches)	Diameter of Bolts (inches)	Number of Bolts (inches)
1	3-1/8	1/2	4	3-1/2	5/8	4	3-1/2	5/8	4
2	4-3/4	5/8	4	5	5/8	8	5	5/8	8
3	6	5/8	4	6-5/8	3/4	8	6-5/8	3/4	8
4	7-1/2	5/8	8	7-7/8	3/4	8	7-7/8	3/4	8
6	9-1/2	3/4	8	10-5/8	3/4	12	10-5/8	3/4	12
8	11-3/4	3/4	8	13	7/8	12	13	7/8	12
10	14-1/4	7/8	12	15-1/4	1	16	15-1/4	1	16
12	17	7/8	12	17-3/4	1-1/8	16	17-3/4	1-1/8	16

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Flange Connections**	Standard Number: **GS 1323.010**
Supersedes: NA		Page 9 of 10

EXHIBIT B

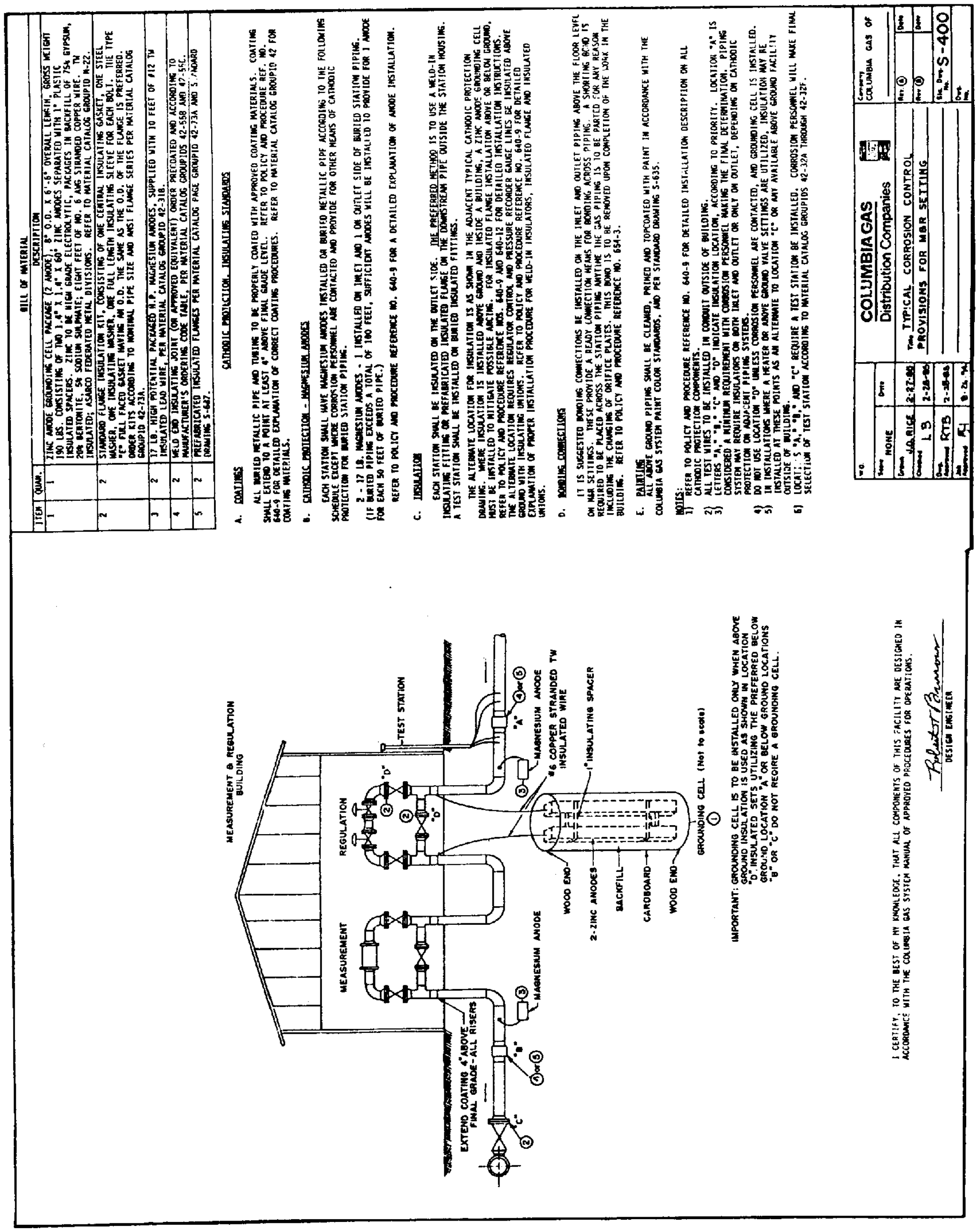


NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Flange Connections	Standard Number: GS 1323.010
Supersedes: NA		Page 10 of 10

EXHIBIT C



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Distribution Operations

Gas Standard

Effective Date: 01/01/2013	Certification of Outside Agencies	Standard Number: **GS 1334.010(CG)** P&P 644-1
Supersedes: 01/22/2003		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE None

1. DEFINITION

"Outside Agencies" are defined as companies which have established programs for the qualification of fusion personnel.

2. CERTIFICATION OF OUTSIDE AGENCIES

Outside Agencies which desire certification to qualify fusion personnel should be directed to contact Technical Training.

After preliminary discussions to establish mutual understanding of the Company's position regarding plastic fusion operations, an inspection visit will be scheduled by Technical Training.

The inspection is to determine that adequate facilities are available, such as:

a. suitable space

b. required tools and equipment

c. record keeping

The Outside Agency will be required to provide a written procedure outlining how qualification records will be maintained and a sample of the qualification document to be provided to non-company personnel for field identification.

Upon acceptance of facilities and qualification record procedure, Technical Training will qualify or verify qualification of the agency's fusion trainers. The agency's fusion trainers will only be authorized to qualify personnel, in accordance with GS 1301.010 "Plastic Pipe and Mechanical Joining Qualification of Personnel" or a fusion qualification program approved by the Company Outside Agencies that qualify fusion personnel through the Company's procedures for fusion joining shall be furnished with the applicable Gas Standards.

After fusion qualification program requirements have been met, Technical Training will provide the Outside Agency with a letter of acceptance.

Thereafter, to maintain the Company certification, the Outside Agency shall be re-qualified annually. Copies of applicable Gas Standards will be furnished during the annual re-qualification to those agencies that qualify personnel to the Company's fusion program.

3. INSPECTION OF FACILITIES

In the letter of acceptance the Outside Agency will be advised that 2 or 3 yearly announced visitations may be made. The purpose of the visits will be to ascertain that:

a. qualification records are being maintained,

b. fusion techniques being used are in accordance with qualified fusion programs,

c. fusion equipment has been maintained, and

d. the qualifier is observing the fusion joining techniques and destructive tests.

Failure of the agency to maintain a certified program that meets Company standards will be cause for decertification of the Outside Agency by the Company.

Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Corrosion Control - General	Standard Number: **GS 1400.010**
Supersedes: 12/31/2012		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.452, 192.453, 192.455, 192.457, 192.491

1. GENERAL

This standard provides an overview of the corrosion control requirements for the protection of metallic pipelines.

All personnel performing corrosion control procedures must be either qualified to perform the procedure or must be working under the direction and observation of a qualified person. Corrosion control procedures include design, installation, operation and maintenance of cathodic protection systems.

For operation, maintenance and installation activities in the GS Series 1400 set of gas standards, "qualified" means that an individual has been evaluated in accordance with the Company's Operator Qualification (OQ) Program training and can perform assigned covered tasks and recognize and react to abnormal operating conditions.

For design activities in the GS Series 1400 set of gas standards, a person meets the requirements of qualification through education, training, and/or experience in corrosion control.

The requirements of this procedure also apply to temporary pipelines unless the Company can demonstrate by tests, investigation, or experience that service of the pipeline will not be detrimental to public safety. Temporary implies that the pipeline will have a service life of less than 5 years.

2. EXTERNAL CORROSION CONTROL REQUIREMENTS

2.1 Pipelines Installed After July 31, 1971

All buried or submerged metallic pipelines installed after July 31, 1971, shall have an approved external protective coating and be cathodically protected. The cathodic protection system should be installed at the time of pipeline installation and shall be placed in operation within one year after the pipeline in-service date. Within one year of the pipeline in-service date, an evaluation shall be conducted to ensure that the pipeline system has adequate cathodic protection. Refer to GS 1430.010 "Evaluation of New Cathodic Protection Systems."

Metal alloy (metallic) fittings are allowed to be installed in plastic pipelines. No cathodic protection is required if the Company can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition and the fitting is designed to prevent leakage caused by localized corrosion pitting. Where the Company is unable to demonstrate by tests, investigation, or experience that cathodic protection is not required, a galvanic anode and test station shall be installed to protect and monitor the isolated metallic fitting. If the metallic fitting is bonded to an adjacent cathodic protection system, then it is not considered isolated, but still must be coated. Refer to GS 1430.020 "External Corrosion Control Monitoring." Within one year of the pipeline in-service date, an evaluation shall be conducted by taking a pipe-to-soil potential measurement to ensure that the isolated metallic fitting has adequate cathodic protection. Refer to GS 1430.110 "Pipe-to-Soil Potential Measurements."

2.2 Pipelines Installed Before August 1, 1971

2.2.1 Transmission Lines

All buried or submerged **transmission lines** shall be cathodically protected.

If a transmission line that was installed prior to August 1, 1971, is discovered and is not currently monitored for cathodic protection, an evaluation of the pipeline (e.g., GS 1430.130 "Surface Potential Survey," GS 1430.230 "Current Requirement Test") shall be performed to determine the next course of action. Within one year of discovery, the transmission line shall be:

a. cathodically protected in its entirety, according to one of the acceptable criteria in GS 1420.020 "Criteria for Cathodic Protection,"

b. replaced (refer to Section 2.1),

c. abandoned, or

d. a combination of the above actions.

2.2.2 Area of Active Corrosion

Active corrosion means continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety.

Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, in which active corrosion is found, must either be cathodically protected, replaced, or abandoned:

a. bare or ineffectively coated transmission lines,

b. bare or coated pipes at compressor, regulator, and measuring stations, or

c. bare or coated distribution lines.

Only the pipeline footage that has been reported with active corrosion needs to be cathodically protected, replaced, or abandoned. Refer to GS 1430.030 or GS 1430.030(PA) “Active Corrosion” for additional guidance regarding areas of active corrosion.

2.3 Steel Pipeline Converted to Natural Gas Service

A steel pipeline converted to natural gas service must meet the requirements for cathodic protection within one year after the pipeline is readied for natural gas service.

NOTE: A bare steel pipeline shall not be converted to natural gas service.

Within one year of the pipeline in-service date, an evaluation shall be conducted to ensure that the pipeline system has adequate cathodic protection, according to GS 1430.010 “Evaluation of New Cathodic Protection Systems.”

3. RECORDS

The Company shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes installed in a stated manner or spacing need not show specific distances to each buried anode.

These records or maps must be retained for as long as the pipe.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/16/2014	Metallic Pipeline Exposures	Standard Number: GS 1410.010
Supersedes: 12/31/2012		Page 1 of 4

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.459, 192.491

1. GENERAL

Whenever the Company has knowledge that any portion of an active buried metallic pipeline (i.e., transmission line, main, service line, or fitting) is exposed for any reason (e.g., leak repair, service line installation, curb valve change, tie-in, anode installation, known exposure by others), its external condition shall be examined and reported.

Whenever any active metallic pipe is removed from a pipeline for any reason, the internal surface shall be visually inspected for evidence of internal corrosion.

Metallic pipeline exposure information is used to supplement a pipeline's history, which can be used to evaluate corrosion areas and present leakage conditions.

Required remedial actions referenced in this procedure are those remedial actions required according to GS 1460.010 or GS 1460.010(VA) "Corrosion Remedial Measures – Distribution" and/or GS 1460.020 "Corrosion Remedial Measures – Transmission." Remedial actions shall be conducted in accordance with Company repair (i.e., GS 1714.020 or GS 1714.020(VA) "Leakage: Distribution Pipe Repair" and/or GS 1730.010 "Transmission Line Field Repair") or replacement (GS Series 3000 Construction) procedures.

2. PIPELINE COATING INSPECTION

If coating exists on the pipeline, the condition shall be examined for deterioration, damage (e.g., scrapes, gouges), or disbondment (e.g, cracking, blistering, chipping, flaking, loose).

If the coating is not bonded to the pipe, the coating shall be removed and the pipe examined for external corrosion in accordance with Section 3.1 below.

NOTE: For coating that is suspected to contain asbestos (e.g., coal tar wrap), any coating that is removed must be collected and disposed of in accordance with the appropriate Environmental, Health, and Safety (EHS) procedure regarding the removal of asbestos-containing coal tar pipe wrap.

If deteriorated, damaged, or disbonded coating can be repaired, refer to GS 1420.035 "Coating Repair Methods for Mill Applied Coatings," GS 1420.040 "Coating Methods for

Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances," or GS 1420.050 "Coating Methods for Fabricated Stations & Settings," as appropriate, for coating repair guidelines. If deteriorated, damaged, or disbonded coating is extensive and cannot be adequately repaired, notify local corrosion personnel.

3. PIPELINE INSPECTION

The following inspections, as applicable, shall be completed on the exposed pipeline.

3.1 External Condition

The external condition of the pipeline shall be examined for evidence of corrosion (or **graphitization** on cast iron) or physical damage. If external corrosion is evident on the exposed portion, an evaluation shall be made circumferentially and longitudinally to determine the appropriate remedial action (e.g., repair, replacement) in accordance with GS 1460.010 or GS 1460.010(VA) "Corrosion Remedial Measures – Distribution" or GS 1460.020 "Corrosion Remedial Measures – Transmission Lines," as appropriate.

a. If no corrosion or damage is found, further investigation is not required.

b. If corrosion or damage is found, but it does not require remedial action (e.g., repair, replacement), further investigation is not required.

c. If corrosion or damage requiring remedial action is found, perform an investigation by examining the pipeline along the entire pipe surface (i.e. circumferentially and longitudinally) to determine the extent of corrosion and/or damage. The examination shall extend beyond the original exposed portion by means of one of the following methods.

   1. Direct Examination - Extend the excavation, if conditions warrant, until no corrosion that requires repair or replacement is found.

   2. Indirect Method (for distribution pipelines only) - Take combustible gas indicator readings reaching into the side banks of the excavation around the pipeline to determine if detrimental corrosion has occurred in the vicinity of the exposed pipeline.

Refer to GS 1714.020 "Leakage: Distribution Pipe Repair" for detailed guidance regarding techniques for examining the external condition of pipelines.

Below are notification requirements for certain conditions found while examining the external condition of Company pipelines.

3.1.1 Transmission Line

If leakage, corrosion, or damage is found on a Company owned **transmission line**, promptly notify a local front line leader/supervisor (see GS 1020.010 "Safety-Related Conditions"). The local front line leader/supervisor shall promptly notify the Company's Integrity Management Personnel for further guidance.

NOTE: Instead of extending the excavation, corrosion personnel may perform an electrical survey, such as surface potential (refer to GS 1430.130 "Surface Potential Survey), CIS (refer to GS 1430.120 "Close Interval Survey"), or DCVG (refer to GS 1430.330 "Direct Current Voltage Gradient (DCVG) Survey") as an indirect method to further investigate the pipeline condition beyond the original excavation.

3.1.2 Distribution Pipeline

Promptly notify a local front line leader/supervisor if:

a. leakage, corrosion, or damage on distribution pipeline (main, service line, or fitting) might result in a **gas pipeline emergency** or affects the integrity of the pipeline, or

b. **general corrosion** or cast iron graphitization is found.

3.2 Internal Condition

If evidence of internal corrosion is found, the adjacent pipe shall be investigated to determine the extent of internal corrosion. Promptly notify local corrosion personnel. If evidence of internal corrosion is found on a Company owned transmission line, the local corrosion personnel shall promptly notify the personnel responsible for managing the Company's Integrity Management Program. A local corrosion front line leader/supervisor, or a designated person qualified in corrosion control, shall initiate an investigation to determine the cause and corrective action necessary to mitigate any further internal corrosion. Refer to GS 1440.010 "Internal Corrosion Inspection Requirements" for additional guidance.

4. INSTALLATION OF APPROVED COATING, ANODE(S), AND/OR TEST STATION(S)

Whenever a bare metallic pipeline is exposed and its surface condition is changed, an approved coating shall be installed, except for cast iron or ductile iron pipe. Damage to existing coatings shall be repaired by using an approved coating. Install anodes (if required) and/or test stations (if required) according to GS 1460.010 or GS 1460.010(VA) "Corrosion

Remedial Measures – Distribution." Refer to GS 1460.010 or GS 1460.010(VA) "Corrosion Remedial Measures – Distribution" or GS 1460.020 "Corrosion Remedial Measures – Transmission," as appropriate, for additional remediation guidance.

5. RECORDS

Results from required external and internal inspections, whether corrosion is or is not found, shall be recorded on the applicable work management work order or other applicable records. Metallic pipeline exposure records shall be retained for at least the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Corrosion Control Design - General**	Standard Number: **GS 1420.010**
Supersedes: 12/31/2012		Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.453

1. GENERAL

The objective of corrosion control is to reduce the maintenance required for a steel piping system. An effective corrosion control design may involve the combination of several of the following factors, as appropriate.

a. Protective Coatings

b. Electrical Isolation and Insulation

c. Cathodic Protection Systems

d. Corrosion Control Test Stations

e. Bonds

f. Stray Current Mitigation

2. DESIGN GUIDELINES

The design of a new or existing corrosion control system shall be performed by or under the direction and observation of a qualified corrosion control person, as defined in GS 1400.010 “Corrosion Control - General.”

The corrosion control design for a new or replacement **pipeline** shall be completed prior to actual pipeline construction so that corrosion control equipment and material (e.g., insulated fittings, test stations, anodes) are readily available for installation during construction. No capital design projects shall be released for construction unless corrosion control recommendations are included. An exception could be emergency capital work that occurs during off hours. In these cases, it may be necessary to give and receive verbal recommendations.

Corrosion control recommendations are required for all planned capital design projects that propose the installation, tie-in, or the abandonment of metallic facilities. Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” (Exhibit A), the modified version of Form GS 1420.010-1 as found in the WMSDocs Library of Templates, or equivalent documentation, shall be used to document the corrosion control recommendations.

For the purpose of this gas standard, “planned capital design projects” are those projects that Engineering has developed capital work order(s) to install and/or retire pipeline facilities for new business, leakage replacement, betterment, or relocation purposes. “Planned” may exclude similar work completed under emergency circumstances.

2.1 Engineering Responsibilities

The engineer or engineering technician responsible for the project design shall complete Part I of Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation and forward it, along with the design drawings or sketch, to the local corrosion person. The following information should be included, as appropriate:

a. work order number,

b. planned pipeline materials - including size and quantity (indicate in Project Description on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation),

c. proposed location of pipeline (e.g., under pavement or sidewalk, north or south side of road) - indicate on work order design drawing,

d. indication of proposed bores and/or casings – indicate on work order design drawing,

e. proposed tie-in method(s) and location(s) to existing system (e.g., insulation and/or isolation needs to be addressed) - indicate on work order design drawing,

f. known locations of other underground metallic facilities (i.e., for stray current considerations) – indicate on work order design drawing,

g. telecommunication involvement (e.g., SCADA or EFC at measurement and regulation stations can cause short circuit to existing cathodic protection system),

h. any preordered material specifications (e.g., special pipe coating applications for boring or above ground installations),

i. reason for project (i.e., new business, leakage replacement, relocation, etc. – identify with appropriate Job Type on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation),

j. proposed project start date, and

k. engineering person's name and contact information.

Engineering shall incorporate the recommendations received from corrosion personnel into the capital design project, indicate the appropriate corrosion control recommendations on the final design drawings or sketch, and include Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation in the work order packet provided for construction.

2.2 Corrosion Personnel Responsibilities

The corrosion person shall complete Part II of Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation and provide the corrosion control recommendations to engineering, which should include the following information, as appropriate:

a. pipe coating, if not already specified,

b. coating inspection method (i.e., holiday detector requirements and setting),

c. joint and holiday coatings,

d. electrical insulation type and location,

e. test station type and location,

f. cathodic protection system type (impressed or galvanic) and location, and

g. corrosion person's name and contact information.

2.3 Construction Personnel Responsibilities

The construction coordinator/inspector or the lead Company person should review the corrosion control requirement documentation provided by the engineer prior to construction and complete Part III of Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation during or after construction.

Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation and the design drawings or sketch should include the following post-construction information, as appropriate:

a. installed corrosion control location references (e.g., test stations, insulating joints)

b. addresses of electrically isolated steel services or risers, and

c. construction coordinator/inspector's or lead Company person's name and contact information.

3. DESIGN CHANGES AFTER CORROSION CONTROL RECOMMENDATIONS

If a design is revised, which could affect corrosion control recommendations (e.g., change in tie-in materials, additional steel pipe, change in project scope), Engineering shall contact corrosion personnel for additional guidance and/or recommendations.

4. FIELD CHANGES TO DESIGN

If changes to the design are necessary during construction (e.g., tie-in location moves, additional steel pipe is installed, or a material substitution is considered), the Company representative responsible for construction shall contact engineering and corrosion personnel, as appropriate, for additional guidance and/or recommendations.

5. RECORDS

The final design drawings or sketch, along with the completed Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation, will be filed with the appropriate work order completion records and retained for the life of the pipeline.

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Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Corrosion Control Design - General**	Standard Number: **GS 1420.010**
Supersedes: 12/31/2012		Page 5 of 7

EXHIBIT A
(1 OF 3)

TRANSMITTAL OF CORROSION CONTROL REQUIREMENTS

(Part I - To be completed by engineering personnel for capital design projects that install, tie-in, or abandon metallic facilities.)

PROJECT			
Date Issued:		Work Order:	
Job Type:		Proposed Project Start Date:	
Engineering Personnel:		Contact Number:	
Project Description: Attach detailed work order sketch and/or engineering plans.			
LOA/TCC:	Street/Address:	City or Township:	County:
Type of System:	DOT Transmission ☐	HP Distribution ☐	Distribution ☐

CORROSION CONTROL CONSIDERATIONS	Y/N/Unkn
Will any steel services (company and/or customer) become electrically isolated or replaced with plastic as a result of this work? If so, provide a list of addresses or a range of addresses.	
Will steel pipeline be installed in casing as part of this project? If so, indicate location(s) on sketch or plans.	
Does steel pipeline cross any other metallic pipelines within this project? If so, indicate location(s) and company contact information on sketch or plans.	
Does any steel pipeline within this project parallel a high voltage A.C. tower line or come within 500 ft. of a substation? If so, indicate location(s) on sketch or plans.	
Does any portion of this project involve steel pipeline near a DC traction system (e.g., electrified railway, mass transit, or mine system)? If so, indicate location(s) on sketch or plans.	
Will any steel pipeline be directional bored as part of this project? If so, is it probable that rock will be encountered?	
Is telemetering (e.g., SCADA, EFC) planned to be installed on any measurement and/or regulator?	
Does any portion of this project involve transmission line within a high consequence area (HCA)?	

PREORDERED MATERIAL SPECIFICATION INFORMATION (e.g., pipe w/special coating, insulators) **NOTE: If coating inspection at the mill is required, notify corrosion personnel minimum one week in advance.**		
Material	Quantity	Comments

When Part I is completed, forward to local corrosion personnel, along with the work order sketch and/or engineering plans.

**EXHIBIT A
(2 OF 3)**

TRANSMITTAL OF CORROSION CONTROL REQUIREMENTS

(Part II – To be completed by corrosion personnel.)

CORROSION PERSONNEL CONTACT INFORMATION		
Date Completed:	Work Order:	
Corrosion Personnel:	Cell:	Pager:
Contact Corrosion Personnel Prior to Construction YES ☐ NO ☐		
Corrosion Personnel to be on Job Site YES ☐ NO ☐		
CORROSION CONTROL SPECIFICATIONS		
Mark-up attached work order sketch or engineering plans w/ proposed location for recommended corrosion control items.		
MILL APPLIED COATING – Include the type of coating, mil thickness, special instructions Coating Mill Inspection Required? YES ☐ NO ☐ If yes, notify corrosion personnel minimum one week in advance.		
ANODES – Include size, description, stock symbol or part number (if appropriate), quantity, and location information (if not provided on attached work order sketch or engineering plans).		
JOINT & HOLIDAY COATINGS/WRAPS – Include size, description, stock symbol or part number (if appropriate), and quantity.		
PRIMERS – Include size, description, stock symbol or part number (if appropriate), and quantity.		
INSULATORS – Include size, description, , quantity, and location information (if not provided on attached work order sketch or engineering plans).		
TEST STATIONS – Include description, stock symbol or part number ((if appropriate), quantity, wire, and location information (if not provided on attached work order sketch or engineering plans).		
OTHER – Include size, description, stock symbol or part number (if appropriate), quantity, and location information (if not provided on attached work order sketch or engineering plans).		
Note: If a cathodic protection circuit will be installed or isolated, the corrosion person needs to denote the necessary record updates (circuit number, database update, etc.). Indicate information on attached work order sketch or engineering plans, when necessary.		
HOLIDAY DETECTION REQUIREMENTS		
Holiday Detection Required YES ☐ NO ☐ See GS 1420.410 "Corrosion Control Design - Inspection of Steel Pipe Coating" for proper volt setting for coating type.		
Comments:		
PRE-CONSTRUCTION COMMENTS		
CORROSION CONTROL TYPE		
Sacrificial Anode System ☐	Impressed Current System ☐ NOTE: Contact local corrosion personnel prior to construction.	Non-Cathodically Protected ☐

When Part II is completed, return to Engineering, along with the work order sketch and/or engineering plans, for inclusion with the work order packet for construction.

2/3
Form GS 1420.010-1
12/31/2012

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Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Corrosion Control Design - General	Standard Number: GS 1420.010
Supersedes: 12/31/2012		Page 7 of 7

EXHIBIT A
(3 OF 3)

TRANSMITTAL OF CORROSION CONTROL REQUIREMENTS

(Part III – To be completed by the construction coordinator/inspector or lead person during construction.)

CONSTRUCTION COORDINATOR/INSPECTOR OR LEAD PERSON ON JOB SITE CONTACT INFORMATION	
Date Completed:	Work Order:
Construction Coordinator/Inspector or Lead Person on Job Site:	Cell:
CONSTRUCTION CORROSION CONTROL INFORMATION	
Type of Mill Applied Coating Installed (e.g., FBE, Powercrete, PE): Thickness of Mill Applied Coating (from print line): Thickness of Mill Applied Coating (if measured; note range of DFT values and anything out of tolerance):	
Type and Manufacturer of Coating used for Girth Welds, Fittings, and Repairs to Mill Applied Coating (e.g., Cold Applied Tape, Epoxy): Thickness of Field Applied Coating (WFT if epoxy or mil thickness & overlap information if tape coating):	
Holiday Detection Completed YES ☐ NO ☐	If Yes, Voltage Setting of Holiday Detector:
Approximate Average Number of Holidays Repaired Per Joint:	
Number of Test Stations Installed: Provide location details of test stations on work order sketch or test point sheet, as applicable.	Number of Insulating Fittings Installed: Type of Insulating Fitting (e.g., monolithic, fiberglass, flange insulation kit): Provide location details of insulating joints on work order sketch or test point sheet, as applicable.
Post-Construction Comments (e.g., tie-in location moved, additional steel pipe installed, material substitution from what was planned/designed):	
The following coated (good coating) steel services or risers have become electrically isolated and must be provided with cathodic protection.	
Address	

NOTE: Indicate installation of anodes and test stations on work order sketch.

When Part III is completed, include within the completed work packet, and return to Engineering or Maps & Records (whichever is appropriate), along with the as-built work order sketch and/or engineering plans, for distribution of applicable items to corrosion personnel.

3/3
Form GS 1420.010-1
12/31/2012

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Criteria for Cathodic Protection	Standard Number: **GS 1420.020**
Supersedes: 04/01/2009		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.463, Appendix D

1. PLANS

Each cathodic protection system shall be designed to provide a level of protection that complies with at least one of the criteria listed in this gas standard.

2. TYPICAL CRITERIA FOR CATHODIC PROTECTION

The following criteria are those normally used within the Distribution Companies to verify adequate cathodic protection.

2.1 -850 mV "On" Potential with IR Drop Considered

A negative (cathodic) voltage of at least 850 millivolts must exist, with reference to a saturated copper-copper sulfate reference electrode. Determination of this voltage must be made with the protective current applied, and voltage (IR) drops other than those across the structure-electrolyte boundary must be considered. Refer to GS 1430.110 "Pipe to Soil Potential Measurements" for additional guidance for considering IR drop. This criterion is most commonly used on galvanic anode cathodic protection systems.

2.2 -850 mV Polarized Potential

A negative polarized potential of at least 850 millivolts must exist relative to a saturated copper-copper sulfate reference electrode. Polarized potential is defined as the potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization. This criterion is most commonly used on impressed current cathodic protection systems with rectifier power source(s) on coated pipeline systems.

2.3 100 mV Polarization Shift

A minimum negative polarization shift of 100 millivolts must exist. The polarization voltage shift must be determined by interrupting the current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading (instant off) after the immediate shift must be used as the base reading from which to measure the polarization decay. This criterion is most commonly used when cathodically protecting a bare or ineffectively coated pipeline.

3. ALTERNATE CRITERIA FOR CATHODIC PROTECTION

The criteria indicated below are not widely used, but are also acceptable.

3.1 Net Protective Current

A net protective current must exist from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

3.2 -300 mV Shift

A negative (cathodic) voltage shift of at least 300 millivolts must exist. Determination of this voltage shift must be made with the protective current applied, and voltage (IR) drops other than those across the structure-electrolyte boundary must be considered.

3.3 Tafel Segment of the E-Log-I Current

A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	Corrosion Control Design – Protective Coatings - General	Standard Number: **GS 1420.028**
Supersedes: N/A		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.461, 192.463

1. GENERAL

Protective coatings shall be installed on all new buried, submerged, and exposed pipelines. Protective coatings used must be approved by the Company.

2. PROTECTIVE COATING SELECTION AND APPLICATION REQUIREMENTS

The protective coating selection and application must meet the following conditions.

a. All coatings must be applied to a properly prepared surface.

b. All coatings must effectively resist underfilm migration of moisture.

c. All coatings must resist cracking.

d. All coatings must have enough strength to resist damage due to handling and soil stresses.

e. All coatings must be compatible with applied cathodic protection.

f. All coatings shall be inspected just prior to lowering into the ditch and backfilling, and any damage to the coating repaired. Refer to GS 1420.410 “Corrosion Control – Inspection of Steel Pipe Coating.”

g. The coatings must be protected from damage due to ditch and/or backfill conditions, or due to supporting blocks.

h. All electrically insulating type of coatings shall have low moisture absorption and high electrical resistance.

i. Precautions must be taken to protect the coatings if the pipe is installed by using boring, driving, or other similar methods.

3. RECORDS

The coating selection for planned capital designed projects shall be communicated via Form GS 1420.020-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation, according to GS 1420.010 “Corrosion Control Design – General.” The completed Form GS 1420.020-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation shall be filed with the appropriate work order completion.

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NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Mill Applied Coatings**	Standard Number: **GS 1420.030**
Supersedes: 01/01/2015		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

This standard applies to the recommended practice for the design of mill applied coatings for new steel pipeline installation.

Local corrosion personnel shall select a coating designed to protect the facilities. Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” should be used to communicate this recommendation.

2. MILL APPLIED COATINGS FOR DIRECT BURIAL

The approved mill applied corrosion coatings for use in below grade applications are Extruded Polyethylene (PE) and Thermoset Fusion Bonded Epoxy (FBE). PE should be considered in congested areas, areas of AC mitigation, areas with high water tables, and rocky soils.

3. MILL APPLIED COATINGS FOR TRENCHLESS INSTALLATION

Approved coatings for trenchless installation are separated into two groups based upon the anticipated abrasion resistance in the proposed bore path.

3.1 Low-Abrasive Environment

3.1.1 Definition

A low abrasive environment is considered to include mud, clay, and sandy soil containing minimal amounts of gravel.

3.1.2 Qualified Materials

Where the proposed bore path is anticipated to pass through a low-abrasive environment, an FBE dual coat should be employed, if commercially available (i.e., 2” diameter steel and greater). A dual coat consists of two layers of FBE, the outer coat being an abrasive resistant overlay (ARO), with a preferred cumulative dry film thickness (DFT) of 32 to 38 mils.

In the event that a dual coat FBE is unavailable, consider one of the following options:

a. a dual coat consisting of a single layer of FBE and a layer of an approved high solids liquid epoxy, with a preferred cumulative dry film thickness (DFT) of 32 to 38 mils depending upon the DFT of the initial FBE layer and the manufacturer instructions of the high solids liquid epoxy,

b. a heavier single layer of FBE (i.e., preferred DFT of 30 to 35 mils), or

c. a coating typically specified for a high-abrasive environment (see Section 3.2.2 below).

3.2 High-Abrasive Environment

3.2.1 Definition

A high-abrasive environment is considered to include rock or dense gravel.

3.2.2 Qualified Materials

Where the proposed bore path is anticipated to pass through an abrasive environment, a single application of FBE with a concrete polymer or liquid epoxy overcoat shall be employed. This dual coating consists of a single layer of FBE with a preferred DFT of 12 to 18 mils over-coated by a minimum of 40 mils of approved concrete polymer or approved liquid epoxy overcoat.

4. MILL APPLIED COATINGS FOR INSERTION INTO CASING

The approved mill applied corrosion coatings for use where coated steel pipeline is inserted into a metallic casing are dual coat Thermoset Fusion Bonded Epoxy (FBE) or FBE with a concrete polymer or liquid epoxy overcoat.

5. INSPECTION OF MILL APPLIED COATINGS

Inspection and quality assurance during the manufacture and installation of mill applied coatings is an essential part of the corrosion control program. Coating inspection shall conform to GS 1420.410 “Corrosion Control - Inspection of Steel Pipe Coating.” Coating inspection at the mill shall also conform to GS 1420.420 “Inspection at the Coating Mill – FBE,” GS 1420.430 “Inspection at the Coating Mill – Epoxy Based Polymer Concrete,” and/or GS 1420.440 “Inspection at the Coating Mill - Extruded Polyethylene.”

6. RECORDS

Records (e.g., forms relating to inspection at the coating mill, Form GS 1420.020-1 “Transmittal of Corrosion Control Requirements”) regarding the milled applied coating application on new steel pipeline installations shall be filed with the appropriate work order completion records and/or recorded in the Company's work management system, or equivalent.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Coating Repair Methods for Mill Applied Coatings**	Standard Number: **GS 1420.035**
Supersedes: 03/01/2010		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

This standard applies to the recommended practice for the repair of approved mill applied coatings including Extruded Polyethylene (PE) coated steel pipe, Thermoset Fusion Bonded Epoxy (FBE) coated steel pipe, and Concrete Polymer coated steel pipe. The standard also applies to the recommended practice for the repair of Coal Tar coated steel pipe and other previously specified bituminous pipe coatings.

The selection of permanent maintenance coatings shall be dependent on the existing mill applied coating except where the local environment or specific conditions may require a deviation from specification. Local corrosion personnel shall select a coating designed to protect the facilities. Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation shall be used to communicate this recommendation for capital projects according to GS 1420.010 “Corrosion Control Design - General.”

All coating products shall be installed in accordance with manufacturer’s documentation.

All coating repairs shall be inspected according to GS 1420.410 “Corrosion Control – Inspection of Steel Pipe Coating.”

2. REPAIRS TO FBE COATED STEEL PIPE

2.1 Qualified Materials

The recommended coatings for use on FBE coated steel pipe are epoxy repair kits. For new or replacement steel pipe installations, approved tape coatings may be used as an alternative if approved by local corrosion personnel (refer to Sections 3.2 and 3.3 below for surface preparation and application requirements when using cold applied tapes). For short installations of steel pipe (e.g., tie-ins) or when repairing existing FBE coated steel pipe (e.g., installation of tap), the coating application may be accomplished with approved epoxy repair kits or tape coatings.

2.2 Surface Preparation

Coatings shall be applied on a properly prepared surface. Surfaces to be coated shall be cleaned by use of a method consistent with manufacturer recommendations to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

2.3 Application

During cold weather installation, ensure that epoxy products have been kept warm per manufacturer instructions. Consideration should be given to cold weather preparation of surface and ambient environment for proper cure of epoxies. Consideration should be given to selecting the optimal product type for the application environment. Match or exceed the thickness of the adjacent pipe coating to ensure adequate electrical inspection of the pipeline coating with a holiday detector.

2.4 Concrete Polymer Coated Fusion Bonded Epoxy

Surface preparation & application of concrete polymer coatings shall be completed per manufacturer's instructions. It is preferred to use the field kit version of the mill applied concrete polymer coating for repairs. Alternatively, an approved liquid epoxy may be used. Special consideration to the mechanical integrity of the repair should be given.

2.5 Proper Curing of Epoxy Coatings

Refer to manufacturer's instructions for curing requirements.

3. REPAIRS TO PE COATED STEEL PIPE

3.1 Qualified Materials

The recommended coatings for use in repairing PE coated steel pipe are cold applied tapes.

3.2 Surface Preparation

Coatings shall be applied on a properly prepared surface. Surfaces to be coated shall be cleaned by use of a method consistent with manufacturer recommendations to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

3.3 Application

During cold weather installation, ensure that the tape has been kept warm per manufacturer instructions.

Tapes shall be overlapped by a minimum of 1-inch or the minimum overlap recommended by the manufacturer, whichever is greater.

Consideration should be made to increase the overlap when covering existing coating (e.g., 2" overlap), installation of coating within a highly corrosive environment, or when a higher dielectric strength of coating is beneficial. Refer to manufacturer's documentation for additional guidance.

Tapes should be applied in a spiral or cigarette wrap per Exhibit A.

4. REPAIRS TO COAL TAR COATED STEEL PIPE AND OTHER BITUMINOUS COATINGS

4.1 Qualified Materials

The recommended coatings for use in repairing Coal Tar coated steel pipe are cold applied tapes.

4.2 Surface Preparation

Coatings shall be applied on a properly prepared surface. Surfaces to be coated shall be cleaned by use of a method consistent with manufacturer recommendations to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

For coating that is suspected to contain asbestos (e.g., coal tar wrap), any coating that is removed must be collected and disposed of in accordance with the NiSource Corporate Environmental, Safety & Sustainability Procedure "Asbestos-Containing Coal Tar Pipe Wrap Removal Procedure."

4.3 Application

During cold weather installation, ensure that the tape has been kept warm per manufacturer instructions.

Tapes shall be overlapped by a minimum of 1-inch or the minimum overlap recommended by the manufacturer, whichever is greater.

Consideration should be made to increase the overlap when covering existing coating (e.g., 2" overlap), installation of coating within a highly corrosive environment, or when a higher dielectric strength of coating is beneficial. Refer to manufacturer's documentation for additional guidance.

Tapes should be applied in a spiral or cigarette wrap per Exhibit A.

5. SOLVENT CLEANING

For the purposes of this procedure, solvent cleaning is accomplished by wiping or scrubbing the surface with rags or brushes wetted with solvent or by spraying the surface with solvent. Use clean solvent and clean rags or brushes for the final wiping or spraying, as applicable.

6. RECORDS

Records regarding the repair coating application on steel pipeline installations (e.g., original coating condition, repair coating type) should be recorded on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation and filed in the work order completion records.

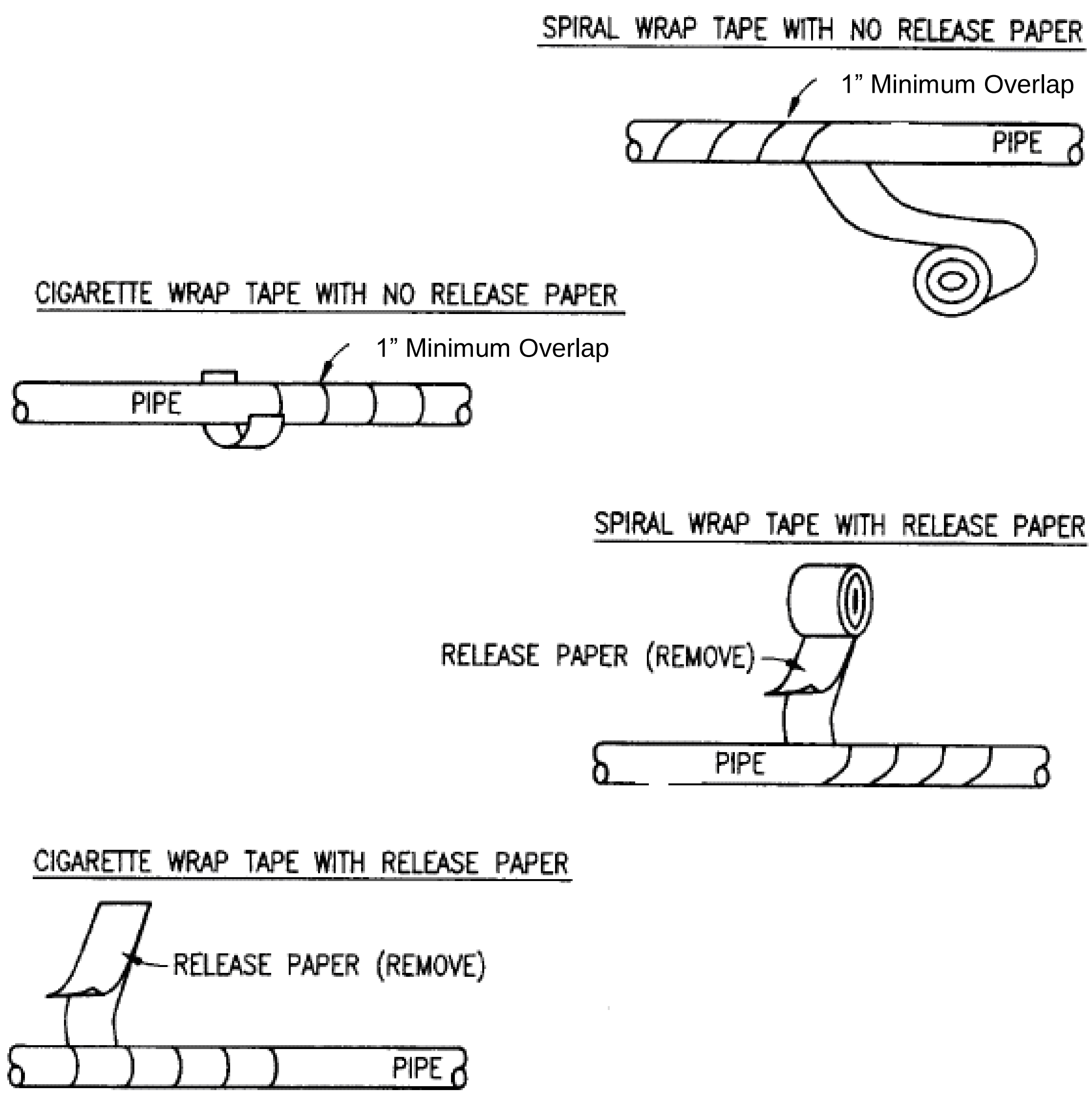
NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Coating Repair Methods for Mill Applied Coatings	Standard Number: **GS 1420.035**
Supersedes: 03/01/2010		Page 5 of 5

EXHIBIT A

Diagrams of Tape Application



NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances	Standard Number: **GS 1420.040**
Supersedes: 09/16/2014		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

This standard applies to the recommended practice for the coating of girth welds, fittings, risers, & other below grade appurtenances. These features are typically field coated except where ordered from the manufacturer pre-coated or coated as part of a shop fabrication.

All coating products shall be installed per manufacturer's documentation.

All coating applications shall be inspected according to GS 1420.410 "Corrosion Control – Inspection of Steel Pipe Coating."

2. COATING OF GIRTH WELDS, FITTINGS, AND OTHER BELOW GRADE APPURTENANCES

The recommended coating for below grade features is dependent on the adjoining mill applied or existing field applied coating.

Approved epoxy coatings are recommended for use with FBE coated pipe. For new or replacement FBE coated steel pipe installations, approved tape coatings may be used as an alternative if approved by local corrosion personnel. For short installations of FBE coated steel pipe (e.g., tie-ins) or when repairing existing FBE coated steel pipe (e.g., installation of tap), the coating application may be accomplished with approved epoxy or tape coatings.

Cold applied tapes should be used with Polyethylene (PE) coated pipe or bare uncoated pipe.

Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation shall be used to communicate this recommendation for capital projects according to GS 1420.010 "Corrosion Control Design - General."

When procuring valves, fittings, and other appurtenances intended for below grade use, consideration should be given to purchasing them pre-coated with an approved coating.

3. COATING OF RISERS

In addition to the requirements of Section 2, the soil to air interface on fabricated risers shall be protected. The approved materials for this include high solids epoxies, cold applied tapes, petrolatum tapes, and wax tapes designed for below grade use. Above grade portions shall be resistant to UV degradation. Additional protection to prevent physical damage to the coating at the interface should be considered.

For atmospheric corrosion remediation, coating approved for both below ground and above ground use should extend approximately 12-inches in each direction below ground and above ground.

4. APPROVED MATERIALS

4.1 Tapes

Tapes provide a relatively simple method for coating without consideration for curing time or mixing of components. Depending on temperature or the condition of the substrate, a primer may be required to achieve optimal performance. Where the coating surface is of irregular contour, approved void filler should be used in conjunction with tape.

Hot applied tapes are sometimes substituted for cold applied tapes where additional resistance to abrasion or resistance to soil stresses is required.

4.1.1 Surface Preparation

Tapes shall be applied on a properly prepared surface. Surface preparation should be in accordance with manufacturer's documentation. Surfaces to be coated shall be cleaned by use of a non-power hand tool to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

4.1.2 Application

Allow pipe to cool prior to tape installation following any welding procedures.

During cold weather installation, ensure that the tape has been kept warm per manufacturer instructions.

Tapes shall be overlapped by a minimum of 1-inch or the minimum overlap recommended by the manufacturer, whichever is greater.

Consideration should be made to increase the overlap when covering existing coating (e.g., 2" overlap), installation of coating within a highly corrosive environment, or when a higher dielectric strength of coating is beneficial. Refer to manufacturer's documentation for additional guidance.

Tapes should be applied in a spiral or cigarette wrap per Exhibit A.

Hot applied tapes require the use of a flash flame to activate the adhesive opposite of the backing film. As the tape is applied, the heat is alternately applied to the pipe and the tape until wrapping is completed.

4.2 Liquid Epoxy

4.2.1 Surface Preparation

Liquid epoxies shall be applied on a properly prepared surface per manufacturer's documentation. Surfaces to be coated shall be cleaned by use of a method consistent with manufacturer recommendations to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

4.2.2 Application

If applying the epoxy after the welding operation, allow pipe to cool to the manufacturer recommended application temperature.

During cold weather installation, ensure that product has been kept warm per manufacturer instructions.

Consideration should be given to cold weather preparation of surface and ambient environment for proper cure of epoxy. Consideration should also be given to selecting the optimal product type for the application environment.

The minimum dry film thickness (DFT) should be 20 mils. It is recommended that a 2-coat application process be utilized to minimize the effects of air entrapment. The total DFT (i.e., same as WFT if 100% solids epoxy) when completed shall meet the requirements of the manufacturer's recommendations. It is recommended to "stripe" the weld or other high points to ensure adequate millage for entire application area.

This should be included in the recommendations in Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation.

4.3 Heat Shrink Sleeves

Heat shrink sleeves shall only be used with approval from local corrosion personnel, using the recommendations in Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation.

Heat shrink sleeves shall not be used on pipelines that pass through bore holes.

Heat shrink sleeves shall be applied on a properly prepared surface in accordance with manufacturer’s specifications.

4.4 Mastics

At this time, mastics are only approved for use in Indiana.

4.4.1 Surface Preparation

Mastic shall be applied on a properly prepared surface. Surface preparation should be in accordance with manufacturer’s documentation. Surfaces to be coated shall be cleaned by use of a non-power hand tool to remove loose rust, scale, dirt, and dust. Solvent cleaning (see Section 5) shall be used to remove visible oil, grease, and other moisture. The surface should be free of any paints or lacquers. All slag, burrs and slivers should be removed from weld areas. Care should be taken to remove loose or poorly bonded coating. Any existing coating shall be removed to the extent necessary to ensure the remaining coating is firmly bonded. The existing coating shall be free of dirt and moisture at the areas to be overlapped.

4.4.2 Application

Allow pipe to cool prior to mastic installation following any welding procedures.

During cold weather installation, ensure that mastic has been kept warm per manufacturer instructions.

Mastics rely on solvent release to cure, requiring extended cure time prior to backfilling or recoat. Mastics should be considered where other approved material applications are impractical.

5. SOLVENT CLEANING

For the purposes of this procedure, solvent cleaning (MEK or other approved solvent) is accomplished by wiping or scrubbing the surface with rags or brushes wetted with solvent or by spraying the surface with solvent. Use clean solvent and clean rags or brushes for the final wiping or spraying, as applicable.

6. PROPER CURING OF COATINGS

Some coating applications require heating of the surface prior to application of the coating for proper curing of the coating. In addition, a wait time period is typically required to allow for proper curing prior to backfilling, and often a curing temperature may need to be maintained for a certain time period. Refer to manufacturer's instructions.

7. INSPECTION OF COATING

Refer to GS 1420.410 “Corrosion Control – Inspection of Steel Pipe Coating” for inspection requirements. The holiday detector voltage setting may require adjustments based on each coating manufacturers’ specifications to ensure adequate electrical inspection of the pipeline coating.

8. RECORDS

Records regarding coatings application on steel pipeline installations should be recorded on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation and filed in the work order completion records..

NiSource
Distribution Operations

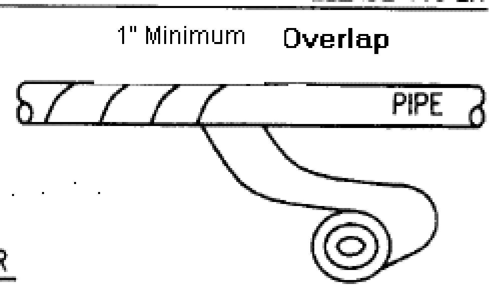
Gas Standard

Effective Date: 01/01/2015	Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances	Standard Number: **GS 1420.040**
Supersedes: 09/16/2014		Page 6 of 6

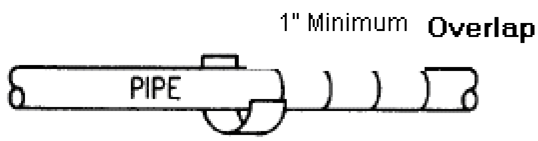
EXHIBIT A

Diagrams of Tape Application

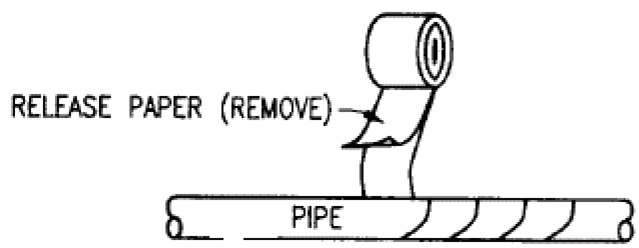
SPIRAL WRAP TAPE WITH NO RELEASE PAPER



CIGARETTE WRAP TAPE WITH NO RELEASE PAPER



SPIRAL WRAP TAPE WITH RELEASE PAPER



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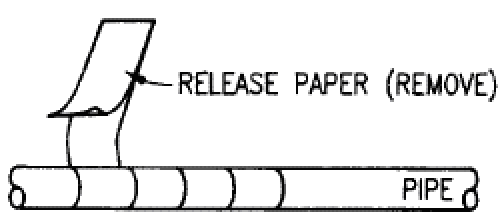

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Coating Methods for Fabricated Stations & Settings	Standard Number: **GS 1420.050**
Supersedes: 03/01/2010		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

This standard provides the recommended practice of coating application for fabricated stations, settings, and above ground piping assemblies.

Application of coating products shall be done in accordance with manufacturer's documentation.

2. ABOVE GROUND COATINGS FOR NEW CONSTRUCTION OR REPLACEMENT

2.1 Purchased Meter Settings

Domestic & commercial prefabricated diaphragm meter settings are typically purchased from outside manufacturers. An approved alkyd enamel system with a minimum dry film thickness (DFT) of 6 mil should be used. The manufacturer may utilize an alternate coating system as part of their manufacturing process with prior Company approval.

2.2 Stations, Settings, and Above Ground Assemblies 8-inches in Diameter and Less

2.2.1 Surface Preparation

Surface preparation shall be in accordance with the coating manufacturer's documentation. The minimum surface preparation shall be a solvent wipe in accordance with SSPC-SP-1 "Solvent Cleaning" to remove all dirt, grease, and contaminating residue.

If a setting is being field fabricated (e.g., small commercial meter setting), solvent cleaning is accomplished by wiping the surface with rags or brushes wetted with solvent or by spraying the surface with solvent (MEK or other approved solvent). Use clean rags or brushes for the final wiping prior to application of the coating.

2.2.2 Coating System

All meter and/or regulator settings, 8-inches in diameter and less, constructed per Company drawings shall be coated with an approved alkyd enamel system. The minimum dry film thickness (DFT) should be 6 mil (e.g., 3 coats of paint if field fabricated). The alkyd enamel shall include a zinc based primer or zinc imbedded enamel (e.g., Rustoleum).

2.3 Stations, Settings, and Above Ground Assemblies Greater Than 8-inch Diameter

2.3.1 Surface Preparation

Surface preparation shall be in accordance with the manufacturer's documentation. The recommended surface preparation for epoxy coating is in accordance with NACE No. 2 / SSPC-SP-10 "Near-White Metal Blast Cleaning."

2.3.2 Coating System

All stations, settings, and assemblies greater than 8-inches in diameter shall be coated with an approved epoxy, over coated with an approved polyurethane for a total system DFT of 12-16 mil.

2.4 Flanged Connections

Above grade flanged connections should be protected from atmospheric corrosion. All flange connections containing a raised face item larger than 2-inch nominal size should be protected through the use of approved void filler products with an approved outer wrap or band. The installation of void filler and/or bands should be completed as part of field installation.

3. MAINTENANCE OF ABOVE GROUND COATINGS

3.1 Preferred Coating Repair Method

Maintenance coatings shall be of the same type as originally installed on the station/setting/assembly, except as noted below in Section 3.2.

In cases where a major recoat is required, the existing coating performance should be evaluated. If the existing coating performance has been inadequate, a suitable approved alternative should be selected.

3.2 Alternate Coating Repair Method

Alternate repair methods include approved coating materials such as epoxies, cold applied tapes, petrolatum tapes, and wax tapes designed for above grade usage.

In high moisture areas, an option is to use a water displacement primer with petrolatum tape or water displacement epoxies.

For soil-to-air interface coating repairs, an option is to use petrolatum tape with an outer wrap (e.g., for protection against mechanized lawn care equipment) or epoxies.

4. COATINGS FOR BELOW GRADE STATION PIPING

Below grade station piping, headers, and the soil to air interface shall be protected. The approved materials for this include high solids epoxies, cold applied tapes, petrolatum tapes, and wax tapes designed for below grade use. Additional protection to prevent physical damage to the coating at the interface should be considered. Above grade portions shall be resistant to UV degradation.

Any below grade station piping greater than 8-inches in diameter should be coated with an epoxy coating to limit the effects of soil stress on the coating.

Below grade epoxies shall be installed per manufacturer's documentation. The minimum DFT should be 20 mil. It is recommended that a 2-coat application process be utilized to minimize the effects of air entrapment. Surface preparation shall be in accordance with manufacturer's documentation. The recommended surface preparation is in accordance with NACE No. 2 / SSPC-SP-10 "Near-White Metal Blast Cleaning."

5. CATHODIC PROTECTION DESIGN AND APPLICATION

The cathodic protection for stations and setting, including isolation and insulation, anode installation, proper coating application, zinc grounding cell consideration, AC stray current design, and cathodic protection monitoring considerations shall be designed according to the Company's applicable corrosion control design gas standards.

All capital designed stations and/or settings shall have corrosion recommendations provided by Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" for details of the cathodic protection requirements.

6. ADDITIONAL REQUIREMENTS

The following requirements apply to all types of stations, settings, and above ground piping of this standard.

a. During priming and painting, the following items shall not be over coated: new galvanized surfaces, stainless steel, aluminum, plastic coated valve handles, equipment nameplates, insulation jacketing, and sight glasses (other than the housing).

b. In locations where the local environment may require a deviation from specification, Engineering, with recommendation from Corrosion personnel, shall select a coating tailored to the special circumstances required to protect the facilities. Form GS

1420.010-1 "Transmittal of Corrosion Control Requirements" should be used in this determination. Examples would include, but are not limited to: areas with salt spray, excessively corrosive environments, vaults, or other areas with limited accessibility.

c. In instances where anticipated service temperature will exceed the recommended service temperature of the default coating, an approved high temperature coating should be applied. An example instance might include a catalytic heater spool.

d. All steel surfaces shall be free of all rough welds, sharp edges, and weld splatter.

e. For over coating, the adhesion of the existing coating should be checked to determine if the existing coating should be removed.

f. Blast media shall not consist of silica sand. Determination of agent shall be made according to the required surface profile.

g. Verification of coating thickness or holidays may be necessary to ensure the integrity of the coating.

7. RECORDS

Follow all recording requirements according to GS 1450.010, GS 1450.010(MA), GS 1450.010(PA), or GS 1450.010(VA) "Atmospheric Corrosion," GS 1460.010 or GS 1460.010(VA) "Corrosion Remedial Measures – Distribution," and GS 1460.020 "Corrosion Remedial Measures – Transmission."

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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Corrosion Control Design – Electrical Isolation and Insulation**	Standard Number: **GS 1420.070**
Supersedes: 05/01/2010		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.467

1. GENERAL

Effective corrosion control requires that all new or replacement of buried or submerged metallic pipeline facilities be electrically isolated from other underground metallic structures (including pipelines), unless the pipeline and other structures are designed to be electrically interconnected and cathodically protected as a single unit. Physical contact with other metallic structures may render the corrosion control system ineffective and create bi-metal corrosion cells. Common underground metallic structures to be avoided are: water, electric, and telephone systems; other pipelines; company pipelines not a part of the cathodic protection system; casings and conduits, etc.

An insulating fitting is a device that is used to electrically isolate sections of a metallic pipeline system to prevent bi-metal corrosion, to facilitate the application of cathodic protection, and/or to sectionalize for troubleshooting purposes.

Types of insulating fittings used for transmission lines and mains are weld-end insulators, insulating couplings, insulated flanges, plastic pipe, and live (hot) line insulators. Other types of insulators used within a pipeline system are insulated unions, meter insulators, casing spacers, insulating hangers for bridge crossings, etc. Methods of isolating pipelines from other metallic structures external to the pipeline system include the use of an electric insulating material such as fiberglass reinforced plastic (also known as FRPs).

Insulation should not be specified in stray current areas until a thorough analysis of the piping system is made.

In all cases for new or replacement insulators, test stations shall be specified and installed with wires on both sides of buried insulators.

2. LOCATION OF INSULATION

Insulation required to facilitate the application of corrosion control shall be installed at locations chosen by local corrosion control personnel. Electrical isolation is required between coated, cathodically protected facilities and bare, unprotected facilities unless they are cathodically protected as a single unit.

2.1 Transmission Lines and Distribution Mains

All new or replaced transmission lines and distribution mains, except "tie-in" pipe and/or fittings, shall be isolated from existing mains at tie-ins, unless the new and the existing systems are coated and cathodically protected as a single unit. The preferred type of insulation for buried pipelines is weld end type insulators.

Insulation is installed in pipelines to sectionalize pipe into shorter sections to facilitate cathodic protection and troubleshooting. The following are suggested maximum spacing for sectionalizing pipelines that are either part of a galvanic anode or an impressed current cathodic protection system:

a. Business Areas 1,500 ft.

b. Residential Areas 3,000 ft.

c. Rural Areas 12,000 ft.

All new or replaced major stream crossings should be isolated from other connecting pipelines, unless protected as a single unit with the adjacent pipeline. All bridge crossings shall be isolated from the bridge structure (by using insulated bridge rollers/hangers with FRPs) and should be isolated from other connecting pipelines.

2.2 Service Lines

To electrically isolate house piping from the service line, insulation shall be installed at gas meter settings any time the meter is installed, changed, or removed.

Any new or replacement coated steel service lines will typically be installed so as to be electrically continuous with cathodically protected metallic mains or transmission lines, except where designated by corrosion personnel. No steel services shall be installed without corrosion control recommendations.

On the contrary, new or replacement coated steel service lines must be electrically isolated from cast iron, wrought iron, or other bare metallic main, with an insulated fitting installed as close to the service line connection to the main (i.e. tap location) as practical. All new or replacement isolated steel service lines shall be installed with corrosion test access points (e.g., test station, outside riser) and a sacrificial anode to protect and monitor for cathodic protection.

Buried isolated metallic fittings installed on new or existing service lines shall be coated and cathodically protected by the installation of a galvanic anode. A test station shall be installed to monitor the isolated metallic fitting. If the metallic fitting can be bonded to an adjacent cathodic protection system (refer to GS 1420.105 "Corrosion Control Design – Bonds."), then it is not considered isolated, but still must be coated.

NOTE: Isolated cathodically protected service lines and electrically isolated metallic fittings may be monitored on a sampling basis over a 10-year period. Refer to GS 1430.020 “External Corrosion Control Monitoring” for additional information.

2.3 Casings

Each metallic pipeline shall be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing. The use of metallic casings with metallic carrier pipe is strongly discouraged from a corrosion control standpoint and should be avoided if at all possible. If the use of a metallic casing with a metallic carrier pipe is mandated (e.g., railroad company), then corrosion control recommendations are required.

2.3.1 New Installations

All new installation of cased metallic pipelines shall provide for the installation of insulating type casing spacers or other suitable means to prevent physical contact between the carrier pipe and casing.

The ends of the casing shall be sealed with casing link seals and/or casing end seals, or other non-conductive sealing methods, to prevent mud, silt, and water from entering the annular space between the casing and carrier pipe.

The annular space shall be filled with a non-conductive type casing filler to ensure continued isolation.

Refer to GS 3010.070 “Casing” regarding the design and/or installation of casing.

2.3.2 Existing Installations

Where there is an indication on existing installations that corrosion is occurring on the carrier pipe or where cathodic protection is rendered inadequate as a result of low resistance between the casing and carrier pipe, practical measures to help ensure adequate corrosion control on the pipeline may consist of one or more of the following:

a. exposing the ends of the casing and physically removing a section of the casing or realigning the carrier pipe to insert an electric insulating material between the casing and the carrier pipe, thereby removing the short,

b. filling the annular space between the carrier pipe and casing with a non-conductive filler and applying additional cathodic protection to the pipe,

c. protect the carrier pipe and casing as a single unit and applying additional cathodic protection to the pipe, and/or

d. removal of casing pipe.

If none of the above options are practicable, then replacement may need to be considered.

2.4 Regulator and Measurement Stations

An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing. Insulation points at regulating and/or measuring stations should be located outside the building, if possible.

Where insulating must be accomplished inside a building, the insulation shall be made on the outlet side of the inlet valve, the outlet side of the bypass valve and outlet side of the outlet valve with an approved flange insulated kit. In this case, when the inlet and outlet piping are electrically isolated, a zinc grounding cell or over-voltage protection device shall be installed as a precaution to mitigate possible arcing.

Electronic equipment, control lines, pressure gauges, by-pass lines, kick braces, etc., that form a conductive path, must also be insulated to isolate a station, if required.

2.5 Induced AC and Fault Current Protection

Wherever excessive induced AC voltages or electrical fault currents exist or are anticipated, measures shall be taken to protect the pipeline and insulating devices from damage and to protect personnel against electrical shock. Such conditions may exist where the pipeline is located in close proximity to high voltage electrical transmission towers, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated.

Insulators are not recommended for installation in sections of the pipeline closely paralleling or crossing high voltage AC tower lines. If necessary, protective measures shall be taken to protect insulators from arcing during fault currents with the installation of zinc grounding cells and/or over-voltage protection device across points of insulation. Each AC mitigation and interference current situation, focusing on both AC corrosion and AC shock hazard, shall be resolved and designed by qualified corrosion personnel at the time of project design or situation discovery. Refer to GS 1420.120 “Controlling AC Interference” for additional guidance.

3. ELECTRICAL ISOLATION EFFECTIVENESS

The effectiveness of electrical insulating devices will be determined when the monitoring of the cathodic protection system as required by GS 1430.020 “External Corrosion Control Monitoring” is completed. If the monitoring shows that the pipeline facility is adequately cathodically protected, electrical isolation will generally be considered to be adequate.

4. RECORDS

Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation shall be used to communicate the design of insulators for planned capital design projects. The final design drawings or sketch, along with the completed Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation shall be filed with the applicable work order completion records.

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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Corrosion Control Design – Sacrificial (Galvanic) Anode System	Standard Number: **GS 1420.080**
Supersedes: 05/01/2010		Page 1 of 10

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

Sacrificial (galvanic) anode systems are normally used for cathodic protection where relatively small amounts of protective currents are required. This type of system is typically used to protect coated distribution pipelines. Advantages of sacrificial anodes are that they seldom cause interference problems, and they have a relatively low installation cost. The most important disadvantages are their limited current output in high resistivity soils, limited “driving” potential, and that they are not practical for complete cathodic protection of bare or poorly coated pipelines.

When soil resistivity is very high (e.g., more than 10,000 ohm-cm) or very low (e.g., less than 2000 ohm-cm), additional considerations should be made with respect to the anode life calculation and anode driving output to sufficiently cathodically protect the pipeline for at least 20 years.

This standard is meant to be used for the design of new installations/replacements of coated steel pipeline and also may be used to design replacement anode systems for systems that have had anode depletion.

Refer to GS 1420.510 “Installation of Galvanic Anodes” for installation guidelines.

2. DESIGN OF A SACRIFICIAL ANODE SYSTEM

The objective of designing a sacrificial anode system is to determine the minimum number and size of anodes needed to meet the cathodic protection criterion of -0.85 volts (-850 mV) and a design life of at least 20 years.

2.1 Standard Size and Use of Specified Anodes

The common sizes of anodes specified include the packaged 17 lb., 9 lb., and 3 lb. high potential magnesium anodes and the 1 lb. zinc anode. Other size anodes, such as drive-in (spike), 32 lb., and 48 lb. magnesium anodes may be purchased when required for a specific design (e.g., if anode life calculation in Section 2.4 below is less than 20 years, then consider a larger anode).

The packaged 17 lb. high potential magnesium anode is normally used for new pipelines and corrosion remedial work, in the design of magnesium anode cathodic protection systems, and anode mitigation installations.

The packaged 9 lb. and 3 lb. high potential magnesium anodes are normally used on maintenance type installations and in the design of magnesium anode cathodic protection systems.

The packaged 1 lb. zinc anode is normally used when required on metallic fittings and valves in plastic systems.

Magnesium has an open circuit potential of approximately -1.70 volts, and zinc has an open circuit potential of approximately -1.05 volts, when measured with respect to a copper-copper sulfate reference electrode.

2.2 Sacrificial Anode Systems for New or Replaced Pipelines

One recommended practice for determining the minimum number of anodes is calculated as follows based on the estimated or measured current requirements and the estimated current output of individual anodes in the soil environment local to that area:

$$N = I / I_a$$

Where: N = the minimum number of anodes needed to meet cathodic protection requirements,

I = the current requirement in milliamperes (mA), and

I_a = the average current anode output in milliamperes (mA)

2.2.1 Current Requirement (I)

The current required to meet cathodic protection requirements is dependent primarily on the coating quality.

For new pipelines, the current required (I) may be estimated by using the following formula.

$$I = A_b \times i$$

Where: I = total current required in milliamperes (mA)

A_b = estimated bare surface area in ft^2

i = estimated current density in mA/ft^2

When designing a sacrificial anode system for new coated steel pipeline, a coating effectiveness of 99.5% should be used, which equates to a bare surface area of 0.5%.

For new installations, it is generally assumed that a current density (i) of 1 to 3 milliamperes (mA) per square foot of bare pipeline surface area will be required.For existing pipelines, determine the required current by performing a current requirement test (refer to GS 1430.230 “Current Requirement Test”).

2.2.2 Average Current Anode Output (I_a)

Anode-to-earth resistance, pipe-to-earth resistance, and soil resistivity are factors influencing the current output of the anode. The resistivity of the soil in which the anode is placed should be determined since this variable is the most important single factor in determining current output of the anode. Ideally, galvanic anodes should be installed in areas with the lowest soil resistivity. The average current output for magnesium or zinc anodes can be determined by the following equations in Table 1.

Table 1

Equations for Calculating Average Current Anode Output (I_a)		
Anode Material	**Bare or Poor Coating**	**Good Coating**
Magnesium	$I_a = 150000\ f\ y\ /\ \rho$	$I_a = 120000\ f\ y\ /\ \rho$
Zinc	$I_a = 50000\ f\ y\ /\ \rho$	$I_a = 40000\ f\ y\ /\ \rho$

Where:

I_a = average current anode output,

f = anode shape factor based on vertical anode installation from Exhibit A,

y = driving voltage factor from Exhibit B, and

ρ = soil resistivity in ohm-cm.

2.3 Sacrificial Anode Systems for Existing Pipelines

When designing a sacrificial anode system for an existing pipeline where anodes have depleted, use the same guidance indicated in Section 2.2 “Sacrificial Anode Systems for New and Replaced Pipelines,” with the exception of estimating the current requirement. The current requirement should be determined by field tests as indicated below.

2.3.1 Current Requirement (I)

Current requirement tests should be performed on existing pipelines so the number of anodes required can be more accurately determined. Refer to GS 1430.230 “Current Requirement Test” for further guidance.

2.4 Anode Life

The life of an anode is primarily determined by the anode’s current output and the anode weight. The life of magnesium and zinc anodes can be determined by the following equations in Table 2.

Table 2

Equations for Calculating Average Anode Life	
Anode Material	**Equation**
Magnesium	Life (yrs) = 0.114 x A x E x UF / I
Zinc	Life (yrs) = 0.0424 x A x E x UF / I

Where:

A = anode weight (lbs),

E = current efficiency expressed as a decimal; anode current efficiency is a measure of the percentage of the total anode current output which is available in a cathodic protection circuit. The remaining current is dissipated in the self-corrosion of the anode material. The anode current efficiency of magnesium ranges from 0.25 – 0.58, high-potential magnesium ranges from 0.45 – 0.54 (typically 0.50 is used as an average), and zinc is approximately 0.90.

UF = utilization factor, which accounts for a reduction in output as the surface area of the anode decreases with time, limiting the anode output. This factor is usually assumed to be 0.85, and

I = current (amps).

3. ANODE LOCATION AND CONNECTION

Anodes should be placed in as low resistivity soil as practical. They shall not be placed so that other structures are between the pipeline and the anode.

An anode should be connected to a pipe wire in a test station in accordance with

GS 1420.090 "Corrosion Control Design – Test Stations" and local practices, which will provide the means to measure the anode current output. This is helpful in determining average anode life and providing average output currents for future estimating.

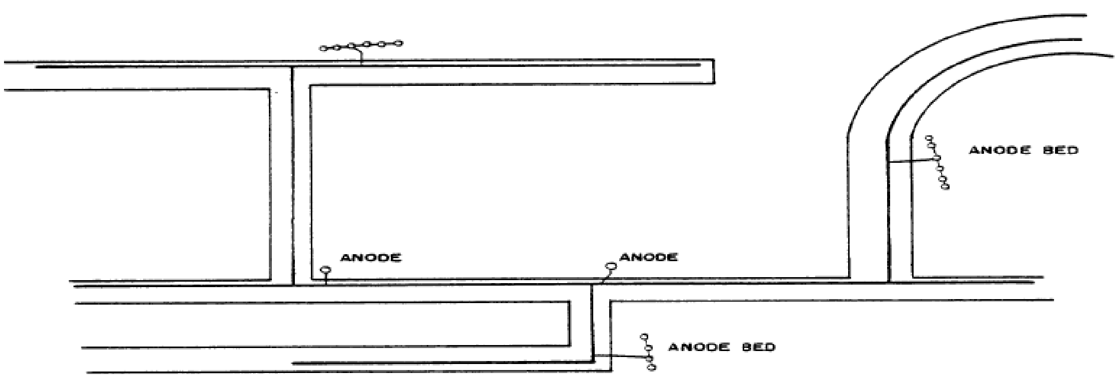
3.1 Distributed Anodes Along the Pipeline – Direct Connection

Typically galvanic anode systems are designed with anodes distributed along the pipeline, each directly connected to the pipeline or connected to the pipeline through a test station.

3.2 Multiple Installation (Bank) Anode Beds – Gathering Wire

Anodes may be installed in multiple anode beds (groups or banks). This method is advantageous on new pipelines or replacements where there are very few services or laterals, in areas of wide variations in soil resistivities, in areas where pipe ditch bottom is sand or rock, and in areas where existing pipe is under paving.

The anodes may be installed in beds in the lower resistivity locations and connected via a common header wire, which should be connected to a pipe wire in a test station.



MAGNESIUM ANODES – CONCENTRATED BEDS

The estimated single anode current output (I_a) must be reduced when anodes are installed in close proximity. Table 3 below shows the reduction factor (C) to be used for various numbers of anodes installed in multiple anode beds at 5, 10, 15, and 20 foot spacing between anodes. The use of a reduction factor is not necessary when anode spacing is greater than 20 feet.

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Table 3

Single Anode Current Reduction Factors (C)						
#Anodes in Distributed Bed	**Anode Spacing**					
	1 foot	**2 feet**	**5 feet**	**10 feet**	**15 feet**	**20 feet**
2	1.46	1.69	1.84	1.92	1.95	1.96
3	1.57	2.06	2.45	2.70	2.79	2.85
4	1.74	2.43	3.04	3.45	3.62	3.71
5	1.93	2.78	3.59	4.19	4.43	4.56
6	2.11	3.13	4.12	4.90	5.22	5.41
7	2.30	3.46	4.65	5.60	6.00	6.22
8	2.48	3.79	5.15	6.28	6.77	7.04
9	2.66	4.11	5.67	6.96	7.54	7.87
10	2.84	4.42	6.16	7.64	8.38	8.68

Example: A single 17 lb. high potential anode current output is estimated at 78 mA in 22000 ohm-cm soil. Cathodic protection current requirement (I) is150 mA. Two (2) 17 lb. high potential anodes spaced at greater than 20 feet will have a combined output of 2 x 78 mA = 156 mA. However, if the two anodes are placed 5 ft. apart, their combined output will be reduced by factor "C":

78 mA x C = 78 mA x 1.84 = 143.5 mA.

Three (3) anodes placed 5 ft. apart will provide:

78 mA x C = 78 mA x 2.45 = 191 mA.

When a multiple anode bed is installed, current attenuation shall be considered. Current attenuation can be considered by use of information typically provided by

NACE and characteristics of environment and pipeline.

New installations and remedial work are subject to cathodic protection verification (refer to GS 1430.120 “Close Interval Survey” and/or GS 1430.010 “Evaluation of New Cathodic Protection System”) to confirm that cathodic protection is achieved over the entire pipeline.

4. GATHERING WIRE SIZING FOR MULTIPLE INSTALLATION ANODE BEDS

The voltage (IR) drop through the gathering wire shall be considered for multiple installation anode bed designs. For anode beds in very low resistivity soils to be connected to the pipe through a single wire, calculate the voltage (IR) drop through the normally used AWG #12 conductor to make certain that the voltage drop is not excessive. If the voltage drop is excessive, specify AWG #8 copper conductor, or install two parallel AWG #12 wires.

Table 4 shows that 1 ft. of AWG #12 copper will have 1 mV drop for each 625 mA being conducted through it.

Table 4

Data Relating to Copper Conductor Wire (Insulated)					
AWG Gauge #	**# of Wires in Strand**	**Diameter (Bare) Inches**	**Resistance Per 1000 Ft. @ 68°F**	**Amps Per MV Per Foot**	**Current Capacity (Amperes)**
0000	19	0.5277	0.04997	20.050	195
000	19	0.4700	0.06293	15.900	165
00	7	0.4134	0.07935	12.620	145
0	7	0.3684	0.10007	10.000	125
1	7	0.3279	0.12617	7.930	110
2	7	0.2919	0.15725	6.360	95
3	7	0.2601	0.19827	5.050	80
4	7	0.2316	0.25000	4.000	70
6	7	0.1836	0.39767	2.520	55
8	7	0.1458	0.52585	1.600	40
10	7	0.1155	1.00848	0.997	30
12	7	0.0915	1.59716	0.625	20
14	7	0.0726	2.54192	0.387	15

In those special cases where excessive current output exists (e.g., an anode bed in very low resistivity soil), a current limiting resistor should be used to prevent excessive potential on coated pipe and to provide longer life for the anodes. The resistor must be selected to have sufficiently high current capacity, voltage, and proper resistance.

5. RECORDS

Refer to GS 1400.010 “Corrosion Control – General” for requirements for recording the location of sacrificial (galvanic) anodes.

Records regarding the design of a sacrificial (galvanic) anode system, such as soil resistivity test results, calculations, etc., should be kept in local corrosion department files for future reference.

EXHIBIT A

Anode Shape Factors (f) for a Vertically Installed Anode		
Anode Weight (lbs)	**Anode Specifications**	**Factor (f)**
Standard Anodes		
3	Packaged	0.53
9	Packaged	0.71
17	Packaged	1.00
32	Packaged	1.06
50	Packaged – anode dimension 8” diam x 16”	1.09
50	Packaged – anode dimension 5” x 5” x 31”	1.29
Long Anodes		
9	2.75” x 2.75” x 26” - backfill 6” x 31”	1.01
10	1.5” x 4.5” x 72” – backfill 4” x 78”	1.71
18	2” x 2” x 72” – backfill 5” x 78”	1.81
20	2.5” x 2.5” x 60” – backfill 5” x 66”	1.60
40	3.75” x 3.75” x 60” – backfill 6.5” x 66”	1.72
42	3” x 3” x 72” – backfill 6” x 78”	1.90
Extra-Long Anodes		
15	1.6” diam x 10’ - backfilled to 6” diam	2.61
20	1.3” diam x 20’ – backfilled to 6” diam	4.28
23	2” diam x 10’ – backfilled to 8” diam	2.81

EXHIBIT B

Driving Voltage Factors (y)			
Target Pipe-to-Soil Potential Reading	**Standard Magnesium**	**High-Potential Magnesium**	**Zinc**
-0.70	1.21	2.14	1.60
-0.80	1.07	1.36	1.20
-0.85	1.00	1.29	1.00
-0.90	0.93	1.21	0.80
-1.00	0.79	1.07	0.40
-1.10	0.64	0.93	--
-1.20	0.50	0.79	--

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Gas Standard

Effective Date: 12/31/2012	Corrosion Control Design – Impressed Current System	Standard Number: **GS 1420.090**
Supersedes: 05/01/2010		Page 1 of 15

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

An impressed current (rectifier) cathodic protection system utilizes an external power source to provide a potential difference between anodes and the protected structure. The anodes are connected to the positive terminal and the structure to the negative terminal of the power source. Current flows from the anodes through the electrolyte (soil or water) and onto the surface of the structure (pipeline).

The protective current output of the power supply is adjusted to deliver sufficient current to overcome the corrosion currents trying to leave the anodic points on the structure. It is desirable to use anode materials that are consumed at lower rates than magnesium and zinc, which are typically used in sacrificial (galvanic) anode systems. Special alloys and combination materials are used in impressed current systems to obtain a long, useful life expectancy from the system.

An impressed current system is capable of protecting large structures or structures which require greater magnitudes of current than can be provided economically by a sacrificial anode system.

Generally, impressed current systems are not suitable for developed areas or areas that will develop in the near future. Impressed current system designs for existing pipelines should take into account anticipated interference problems to ensure that necessary precautions are taken for mitigation.

The design of an impressed current system shall be performed by qualified corrosion personnel. A person meets the requirements of qualification through education, training, and/or experience in corrosion control.

2. DESIGN OF AN IMPRESSED CURRENT SYSTEM

The major factors to be considered in the design of an impressed current system are total current required, availability of power, ground bed location, ground bed type, ground bed resistance, current output per anode, number of anodes, anode life, cable size, rectifier size, location of foreign structures, and interference currents.

Impressed current systems shall be designed to minimize adverse effects on foreign underground metallic structures. Detrimental interference currents shall be mitigated to the mutual satisfaction of all parties involved.

Electrical continuity in the piping to be protected by an impressed current system shall be achieved by bonding non-conducting fittings as required. Refer to GS 1420.105 "Corrosion Control Design - Bonds."

2.1 Current Requirement (I)

To properly design an impressed current system, it is important to determine the total current required to protect the pipeline under consideration. The total current required is the sum of the current required for cathodic protection of the piping plus any interference currents required to be returned through bonds with other structures. Refer to GS 1420.100 "Corrosion Control Design – Stray Current Control" for guidance on how to account for anticipated interference issues. The total current should be increased by at least 25% to account for future requirement increases. This total current will be the current output required from the ground bed.

Total current required is best determined by performing current requirement tests in the field. The pipeline to be tested for current requirements should be insulated from all other foreign structures and must be electrically continuous. Refer to GS 1430.230 "Current Requirement Test" for further guidance.

In those cases where no interference with other structures is anticipated, the current required can be estimated. Current requirement estimates may be made to determine the approximate amount of current required to protect a pipeline. Estimating should only be done when experience and past data in similar areas and circumstances are available from which to base the estimate.

2.2 Standard Ground Bed Design

There are several steps to be taken in designing an impressed current ground bed. The initial steps include selecting a ground bed site and type.

Ground beds should be designed to meet a ground bed resistance of 2.5 ohms or less. Exceptions to this may be necessary where a thorough resistivity survey and investigation fail to find a more suitable ground bed site.

2.2.1 Ground Bed Location

The following factors should be considered when locating a ground bed site:

a. soil resistivity,

b. soil moisture,

c. type and condition of the pipeline,

d. possible problems/interference with foreign structures,

e. availability of power supply,

f. availability of land (right-of-way or easement),

g. accessibility for construction and maintenance, and

h. future plans for the area.

Simulating a temporary ground bed is recommended to determine those sites considered most suitable for permanent installations. This will give test data that can be used to determine current required for protection and interference current problems to be anticipated with other structures.

A suitable site is one located in low resistivity soil, at a location remote to other underground metallic structures, and where commercial power is available.

2.2.2 Ground Bed Types

There are three basic types of ground beds used: conventional, distributed, and deep anode.

a. Conventional (Remote) Ground Beds

This type of ground bed is constructed at a point where the anode gradient is remote (typically more remote than for distributed ground beds) from the pipeline to be protected. For example, the minimum distance between the first anode of the ground bed and the pipeline can be 100 feet for coated pipeline and 300 feet for bare pipeline. However, those distances may need to be adjusted in urban areas where this spacing may not be practical.

When a foreign underground metallic structure is in proximity of the ground bed, every effort must be made to minimize interference problems.

In general, when practical, a conventional ground bed should be located in a soil resistivity less than 10,000 ohm-centimeters; otherwise, the result will be a high ground bed resistance.

A conventional ground bed may require a purchased easement, the land of which must be available and may be costly. However, if the land is available, the cost of installation and maintenance is less than a deep anode system.

b. Distributed Ground Beds

This type of ground bed may be advantageous where current requirements are high and foreign structures make interference a major problem, and/or soil resistivity is very high. The distributed system creates lower potential gradients and less interference problems and can usually be installed in existing right-of-way. This type of ground bed is not suitable where more than a few services are present, and it is impractical in paved locations.

In a distributed ground bed, impressed current anodes are connected to a gathering wire that is run along the length of the pipeline to be protected. The anodes with backfill are installed closely parallel to the pipeline to be protected and within the right-of-way. Distributed ground beds shall not be located so that a foreign metallic structure is between the anodes and the protected pipeline for any appreciable parallel length.

c. Deep Anode Ground Beds

The deep anode ground bed is a special case of a conventional ground bed. The anodes are installed vertically at depths generally up to 350 feet. The deep anode ground bed is generally more expensive and has historically experienced a higher incidence of failure. However, some of the advantages of a deep anode ground bed are that they may:

1. be located in congested areas,
2. provide lower resistance than conventional ground beds in areas of high-resistivity surface soils, and
3. provide better current distribution than conventional ground beds.

Anodes should be placed at a minimum spacing of 15 feet, but should be designed to allow the maximum anode output in low soil resistance areas.

The deep anode ground bed shall be designed with vent pipe(s) to vent gases away from anodes. In addition, connections to anodes shall be made outside of the anode column. No splice connections shall be made inside of the anode column.

A recommended best practice is to use a 0.001 ohm shunt with each individual anode connection in an approved outside fiberglass junction box for measurement of anode current output.

A “drop-in-place” type deep anode ground bed is illustrated in Exhibit A.

2.2.3 Anode Considerations

The type of anode used within an impressed current ground bed depends on the characteristics of each situation. The most common types of anodes used within a conventional ground bed are listed in Table 1 below:

Table 1

Anode Material	Operating Density Range (Max Output per Anode)	Average Consumption Rate
High-Silicon Cast Iron	0.5 – 2.5 amp/ft^2	0.75 lbs/amp-year
Graphite	0.2 – 1.0 amp/ft^2	2.0 lbs/amp-year
Mixed Metal Oxide	9 amp/ft^2	0.000011 lbs/amp-year
Scrap Steel	1 – 3 amp/ft^2	20 lbs/amp-year

2.2.4 Calculating the Number of Anodes Required

The number of anodes may be calculated by comparing the results of the following formulas and choosing the highest calculated value.

Formula 1:

Part 1:

Total Wt of Anodes Reqd = Consumption Rate x Desired Life x Reqd Current / UF

Where:

Consumption Rate = Rate from Table 1 or anode manufacturer's specifications
Desired Life = typically, 20 years
Reqd Current = estimated or determined by test (see Section 2.1)
UF = Utilization Factor, the amount of anode material that can be lost to consumption before anode replacement is required (typically, 0.60 or 60%)

Part 2:

No. of Anodes Reqd = Total Wt of Anodes Reqd / Anode Weight

Where:

Total Wt of Anodes Reqd = Results from Part 1 of Formula 1 above
Anode Weight = anode manufacturer's specifications

Formula 2:

No. of Anodes Reqd = Reqd Current / Max Output per Anode

Where:
Reqd Current = estimated or determined by test (see Section 2.1)
Max Output per Anode = Rate from Table 1 or anode manufacturer's specifications

2.2.5 Calculating the Anode Bed Resistance-to-Earth

The formulas below can be used to calculate the anode bed resistance-to-earth (R_{Gbed}). However, graphs from the anode manufacturer may also be used instead of the formulas to determine the anode bed resistance-to-earth for typical anodes.

a. Anode Bed Resistance of Multiple Vertical Anodes

$$R_v = \frac{0.0052\rho}{NL}\left\{\left(\ln\frac{96L}{d}\right) - 1 + \frac{2L}{S}\ln(0.656N)\right\}$$

Where, R_v = Resistance of multiple vertical anodes to remote earth (ohms)

ρ = Resistivity of electrolyte (ohm-cm)

L = Length of anode (ft)

d = Diameter of anode (in)

S = Anode spacing (ft)

N = Number of anodes

b. Anode Bed Resistance of a Single Vertical Anode (e.g., deep anode system)

$$R_v = \frac{0.0052\rho}{L}\left\{\left(\ln\frac{96L}{d}\right) - 1\right\}$$

Where, R_v = Resistance of single vertical anode to remote earth (ohms)

ρ = Resistivity of electrolyte (ohm-cm)

L = Length of anode (ft)

d = Diameter of anode (in)

c. Anode Bed Resistance of a Horizontal Anode

$$R_H = \frac{0.00521\rho}{L}\left\{\ln\left(\frac{48L^2 + 48L\sqrt{S^2 + L^2}}{dS}\right) + \frac{S}{L} - \frac{\sqrt{S^2 + L^2}}{L} - 1\right\}$$

Where, R_H = Resistance of a single horizontal anode to remote earth (ohms)

ρ = Environment resistivity (ohm-cm)

L = Length of anode (ft)

d = Diameter of anode (in)

S = Twice the depth of anode (ft)

2.3 Coke Breeze Backfill

Carbonaceous coke breeze backfill is used to surround most impressed current anodes to reduce the anode bed resistance, provide a uniform environment for current discharge, and extend the anode life. The two types of coke breeze backfill approved for use in ground beds are metallurgical coke breeze and calcined petroleum coke breeze.

Metallurgical coke breeze should not exceed 50 ohm-cm resistance. It is available bagged or bulk and is often used in prepackaged impressed current anodes.

Calcined petroleum coke breeze is much more conductive than metallurgical grades of coke. Its resistance should be less than 2 ohm-cm. Since resistance values are low, high current density is less prone to gas generation and the incidence of gas blocking in deep anode beds using a 92 percent carbon content coke is rare. Some grades incorporate a surfactant, similar to detergent, to reduce water tension and promote pumping and compaction in deep anode beds.

Table 2 below may be used to calculate the dry volume of coke breeze (specifically, Loresco Type SC-3) required versus hole size backfilled required for a deep anode ground bed. Use specific manufacturer’s literature if another type of coke breeze backfill is used.

Table 2

Hole Size	Dry Amount of Loresco Type SC-3 Coke Breeze Required			
	(cu. ft. / lineal ft.)	(lbs. / lineal ft.)	(lineal ft. / 100 lbs.)	(lbs. / 100 ft. of hole)
4”	0.087	6.4	15.70	640
6”	0.196	14.3	6.99	1430
8”	0.349	25.5	3.93	2550
10”	0.545	39.8	2.51	3980
12”	0.784	57.2	1.75	5720

Example: A deep anode ground bed is designed with an 8-inch diameter drill hole of a length of 200 feet anode active area. The dry amount of coke breeze backfill needed is calculated to be:

200 ft. x 25.5 lbs./lineal ft. = 5100 lbs.

2.4 Cable Connections

Two methods are commonly used to connect the anodes:

a. Anodes connected by a gathering cable loop (to be used for a convention ground bed system only) or

b. Individual anodes connected by leads into a gathering junction box (allows for reading the current output of each anode).

For new impressed current groundbed designs, the minimum cable size used in ground beds and for rectifier connections to a pipeline is No. 8 AWG. However, the cables should be sized to minimize resistance (generally, cable resistance should be less than 0.25 ohms; see the table in Exhibit B).

The cable insulation coating shall be HMWPE, or if chlorine gas exists, another type of insulation coating may be specified, such as Kynar or Halar.

2.4.1 Calculating the Cable Resistance

The cable resistance (R_C) for a gathering cable loop (method “a” indicated above in Section 2.4) can be calculated based on the effective system cable length and the resistance of the cable per linear foot indicated in the following formula:

$$R_C = (R_{cable} \times L_{cable})_{neg} + (R_{cable} \times L_{cable})_{pos1} + 1/2\ (R_{cable} \times L_{cable})_{pos2}$$

Where:

R_{cable}	=	resistance per linear foot of cable based on the standard cable resistance provided in the table in Exhibit B
L_{cable}	=	measured length of cable (ft)
$(R_{cable} \times L_{cable})_{neg}$	=	use resistance and length for the negative return cable
$(R_{cable} \times L_{cable})_{pos1}$	=	use resistance and length for the positive cable to the first anode
$(R_{cable} \times L_{cable})_{pos2}$	=	use resistance and length for the positive cable between the first and last anodes

The cable resistance (R_C) for anodes that are gathered individually into a junction box (method "b" indicated above in Section 2.4) can be calculated by the following formula:

$$R_C = (R_{cable} \times L_{cable})_{neg} + (R_{cable} \times L_{cable})_{pos} + (R_{cable} \times L_{cable})_{long}$$

Where:

R_{cable}	=	resistance per linear foot of cable based on the standard cable resistance provided in the table in Exhibit B
L_{cable}	=	measured length of cable (ft)
$(R_{cable} \times L_{cable})_{neg}$	=	use resistance and length for the negative return cable
$(R_{cable} \times L_{cable})_{pos}$	=	use resistance and length for the positive cable
$(R_{cable} \times L_{cable})_{long}$	=	use resistance and length for the longest length of cable connecting an anode through the junction box

2.5 Total Circuit Resistance

The total circuit resistance (R_T) consists of the anode bed-to-soil resistance (R_{Gbed}), the cable resistance (R_C), and the pipeline (structure)-to-earth resistance (R_E).

$$R_T = R_{Gbed} + R_C + R_E$$

Where:

R_{Gbed}	=	see Section 2.2.5
R_C	=	see Section 2.4.1
R_E	=	R_{ctg} / A

Where:

R_{ctg} = coating resistance (ohm-ft^2), estimated or from manufacturer's specifications

A = surface area of pipe (ft^2)

Coating resistance (ohm- ft^2) may be estimate by using the following range of values shown in Table 3 below.

Table 3

Coating Condition	Coating Resistance (ohm- ft²)
Poor Application or Handling During Installation	10,000 – 25,000
Good to Excellent Application and Handling During Installation	100,000 – 5,000,000 (500,000 is typically assumed)

2.6 Standard Rectifier Sizing

The final step in designing an impressed current system is sizing the direct current (DC) output of the power supply to be used.

New rectifiers shall be of a high quality cathodic protection type. Air-cooled, diodes or diode modules, single phase bridge, 240/120 Volts alternating current (VAC) input voltage units are typically specified. In addition, a convenience outlet is often specified to run interrupters or power tools.

Lightening arresters shall be specified in both the AC and DC side. A choke efficiency device should also be specified.

A weatherproof service box with provisions for locking the box door and external handle shall be specified. The installation shall conform to national and local electrical code requirements.

In order to size the DC output of the power supply, the required rectifier voltage (V_R) needs to be determined as follows:

$V_R = (I \times R_T) + V_b$

Where:

I = total current required (see Section 2.1)

R_T = total circuit resistance (see Section 2.5)

Vb = back voltage, which is the voltage that exists in opposition to the applied voltage between the anodes and the protected pipeline. (Anode bed anodes with carbonaceous backfill will usually have a back voltage of about 2 volts, unless experience in a specific area dictates otherwise.)

The final specific size of the rectifier may allow for extra voltage capacity for increasing ground bed resistance with time and extra current capacity for changing conditions in the future.

2.7 Electric Power Requirements

Most electric companies will allow for a maximum of 100 amp service, which requires a minimum of #8 copper wire for the AC inlet cable. However, a #4 stranded copper cable is recommended for most applications.

The electric service shall have a lockable external shut off or disconnect.

Efficient grounding of at least 5 ohms is required. The neutral wire shall be identified.

A typical rectifier installation is shown in Exhibit C.

2.8 Solar Panel Systems

Solar panel systems are ideal for low current requirements or if electricity is not available.

Follow manufacturer’s installation instructions, and don’t install solar panels in the shade.

3. RECORDS

Refer to GS 1400.010 “Corrosion Control – General” for requirements for recording the location of cathodic protection facilities.

Records regarding the design of an impressed current system, such as soil resistivity test results, calculations, etc., should be kept in local corrosion department files for future reference.

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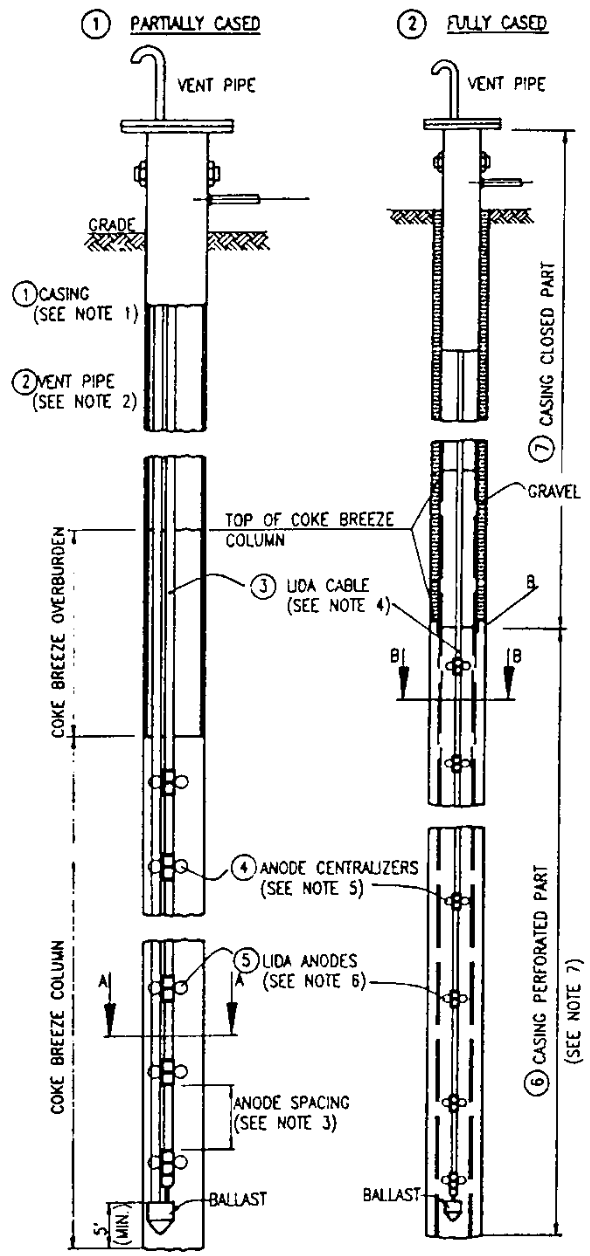

MATERIAL LIST

1. CASING NON METALLIC DIA. RANGE 6"–8" OR COATED STEEL SAME DIA.
2. PIPE 0.8" DIA. PVC OR PE FLEXIBLE PERFORATED
3. CABLE UDA CABLE
4. ANODE CENTRALIZERS GALVANIZED CARBON STEEL ANODE DIA. 1"
5. ANODE UDA TUBULAR 1" DIA. x 40" LONG CONNECTED ON UDA CABLE
6. CASING NON METALLIC DIA. HALF OF THE BORE HOLE DIA. PERFORATED OPEN SURFACE 25%
7. CASING NON METALLIC DIA. HALF OF THE BORE HOLE DIA. NON-PERFORATED
8. JUNCTION BOX (IF REQUESTED)
   1 TERMINAL FOR ONE UDA STRING DGB
   2 TERMINALS FOR TWO UDA STRINGS DGB
9. TUBE PVC 3" DIA. TWO ENDS THREADED
10. BLOCKAGE RINGS PVC INTERNALLY THREADED FOR 3" PVC PIPE
11. TIE CABLE 13.75" LONG NYLON
12. POLE WOOD 6" DIA.
13. COUPLING NON METALIC PVC INTERNALLY THREADED FOR THE ① DIA.
14. BACKFILL PETROLEUM CALCINATED COKE BREEZE

NOTES

① THE CASING HAS TO BE INSTALLED ACROSS ALL THE COLLAPSABLE STRATA TO REACH STABLE STRATA BELOW THE GROUND WATER STATIC LEVEL

② THE FLEXIBLE 1" DIA. PLASTIC VENT PIPE SHALL HAVE HOLES (0.2"–0.118" DIA.) DRILLED OVER THE FULL LENGTH OF THE VENT PIPE THAT IS TO BE EMBEDED IN THE COKE BREEZE BACKFILL

③ THE DEPTH OF THE HOLE AND THE QUANTITY OF ANODES INSTALLED IN INDIVIDUAL GROUND BEDS SHALL BE DETERMINED BY THE SPECIFIC JOB REQUIREMENTS

④ THE UDA CABLE HAS A DUAL INSULATION

⑤ ONE CENTRALIZER PER ANODE SHALL BE USED AND MOUNTED OVER THE COPPER RING AT THE ANODE CENTER

⑥ THE UDA ANODES ARE MIXED METAL OXIDES ACTIVATED TITANIUM TUBES

⑦ THE CASING SHALL BE PERFORATED WITH SLOTS OR HOLES THE HOLES SHALL BE DRILLED WITH 45DEG. ANGLE

⑧ A PVC TUBE WITH BOTH ENDS THREADED SHALL BE USED AS ANODE STRING SUPPORT

⑨ THE COKE BREEZE BACKFILL SHALL PREFERABLY BE FLUIDIZED WITH WATER TO FORM A SLURRY AND PUMPED INTO THE GROUNDBED HOLE FROM THE BOTTOM UP UTILIZING A SEPARATE LOADING PIPE

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<table>
<tr><td>Effective Date:
12/31/2012</td><td rowspan="2">Corrosion Control Design – Impressed Current System</td><td>Standard Number:
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05/01/2010</td><td>Page 13 of 15</td></tr>
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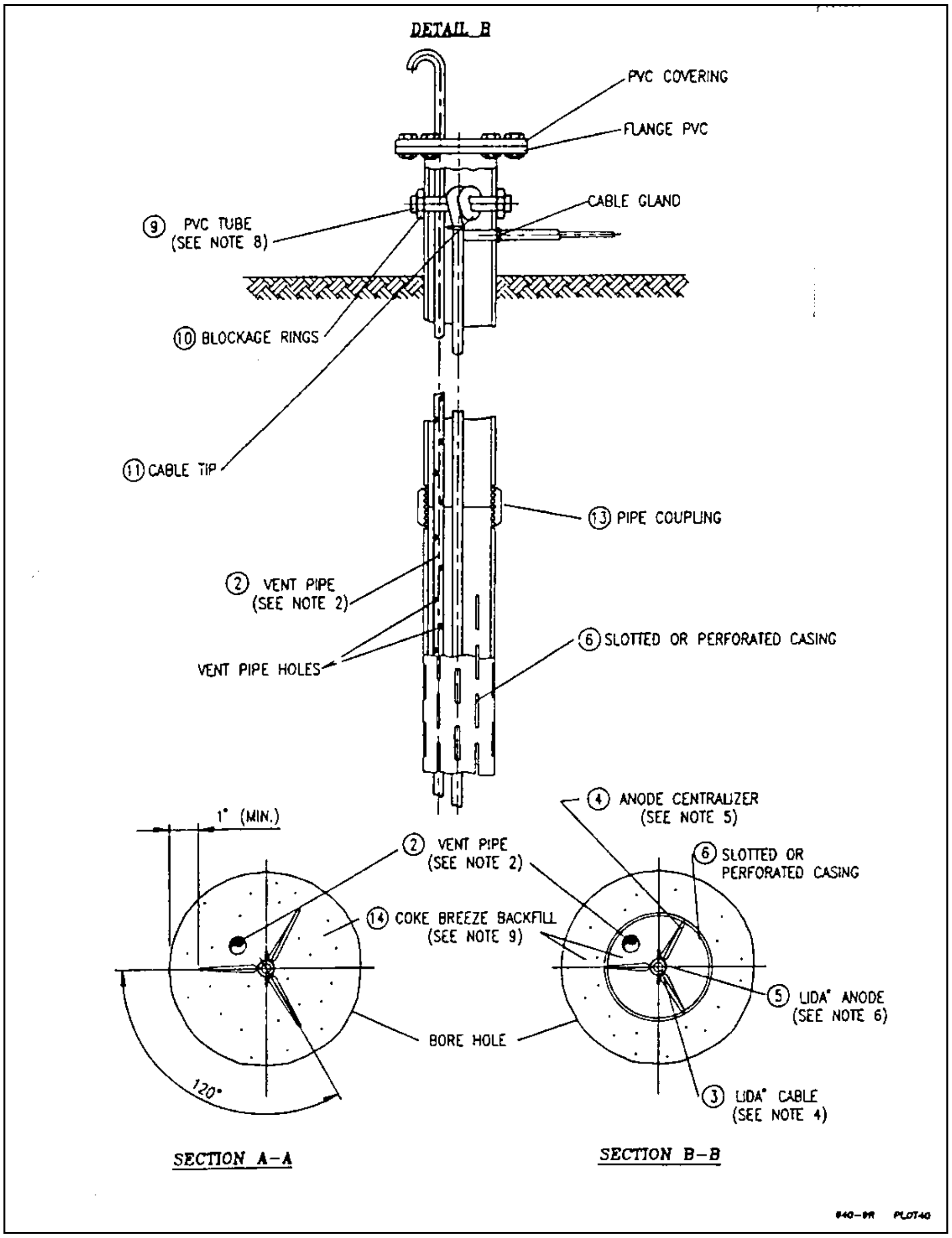

EXHIBIT B

Data Relating to Copper Conductor Wire (Insulated)					
AWG Gauge #	**# of Wires in Strand**	**Diameter (Bare) Inches**	**Resistance Per 1000 Ft. @ 68°F**	**Amps Per MV Per Foot**	**Current Capacity (Amperes)**
0000	19	0.5277	0.04997	20.050	195
000	19	0.4700	0.06293	15.900	165
00	7	0.4134	0.07935	12.620	145
0	7	0.3684	0.10007	10.000	125
1	7	0.3279	0.12617	7.930	110
2	7	0.2919	0.15725	6.360	95
3	7	0.2601	0.19827	5.050	80
4	7	0.2316	0.25000	4.000	70
6	7	0.1836	0.39767	2.520	55
8	7	0.1458	0.52585	1.600	40
10	7	0.1155	1.00848	0.997	30
12	7	0.0915	1.59716	0.625	20
14	7	0.0726	2.54192	0.387	15

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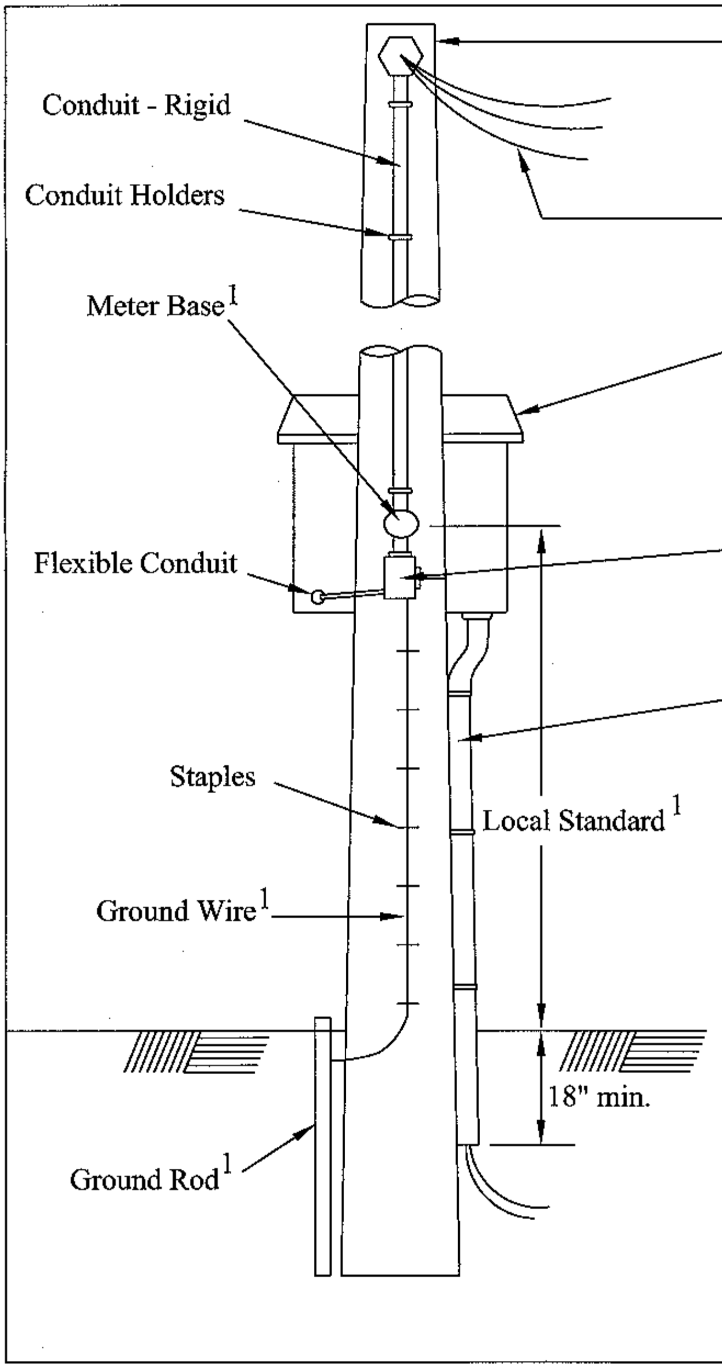
EXHIBIT C



Notes:

1. Refer to local electrical code for specifications

2. Switch box must be grounded

3. Rectifier case should be labeled with "Caution - High Voltage" or similar warning

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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.469, 192.491

1. GENERAL

A sufficient number of test stations or other test points shall be designed for electrical measurement to determine the adequacy of cathodic protection (CP).

Local corrosion personnel qualified as defined in GS 1400.010 “Corrosion Control – General” shall determine the number, locations, and types of test stations that are required. For designed capital projects, this information shall be recorded onto Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” and/or the work order drawings or engineering plans. For test stations installed on operating and maintenance type work orders, the information can be explained in work order comments or verbally.

Refer to GS 1420.520 "Installation of Test Stations" for guidance on the documentation required for test stations that are installed.

2. LOCATION OF TEST STATIONS OR TEST POINTS

Minimum test station or test point separation will generally be governed by insulating points, traffic conditions, reading accessibility, etc. Test stations or test points should be located in readily accessible locations free of traffic hazards and free from future paving or construction.

Test stations shall be installed on new cathodically protected pipelines at the following locations:

a. underground insulators,

b. steel carrier pipe inserted into metallic casings (recommended on each side of the cased crossing),

c. crossings of foreign gas, oil, or petroleum products lines,

d. points of interference current,

e. major water crossings (recommended on each side of the crossing), and

f. a sufficient number of other points to ensure the adequacy of cathodic protection.

While it is impractical to specify a standard separation between test points, consideration should be given to the following suggested spacing:

a. Business Areas: 750 ft.

b. Residential Areas: 1,500 ft.

c. Rural Areas: 6,000 ft.

NOTE: In AC influence areas, a sufficient number of test stations (TS) to monitor/test for AC influence are recommended. When crossing the AC corridor, install TS at the entrance and exit locations (e.g., 3-4 TS) spaced approximately 100 feet apart along the pipeline moving away from the AC corridor. When paralleling the AC corridor, then install TS spaced approximately 500 feet apart (i.e., typical length of zinc ribbon). When the pipeline has been paralleling the AC corridor, then install additional TS where the pipeline travels away from the AC corridor in each direction (e.g., install 3-4 TS spaced approximately 100 feet apart along the pipeline moving away from the AC corridor).

3. DETERMINING THE NUMBER OF TEST POINTS NEEDED FOR MONITORING CATHODIC PROTECTION

The number of test points or test stations needed to adequately monitor cathodic protection is not a set number. The number is determined as a result of testing, troubleshooting, and managing the history of leaks.

For new or replacement pipelines, the tests required by GS 1430.010 “Evaluation of New Cathodic Protection Systems” help to establish system low points to be set up for cathodic protection monitoring.

For existing systems under cathodic protection, new test points may be added or existing test points may be adjusted via reference electrode placement, based on troubleshooting results (refer to GS 1430.410 “Cathodic Protection Troubleshooting Methods”), due to inadequate cathodic protection monitoring readings (refer to GS 1430.020 “External Corrosion Control Monitoring”) and/or leaks on pipelines under cathodic protection (refer to GS 1460.030 “Investigating Leaks on Coated Pipeline”).

4. TYPES OF TEST STATIONS

Several types or combinations of types of test stations may be required to determine the adequacy of cathodic protection. The basic types by function are discussed below.

a. Pipe-to-Soil Potential – Typically used on either a galvanic anode or impressed current CP system when setting up a test point where no anode is located or needed. See page 1 of 10 of Exhibit A.

b. Magnesium Anode (single or multiple anode) – Typically used on either a galvanic anode or impressed current CP system when setting up a test point at an anode location. For galvanic anode CP systems, the anode is connected to the pipeline through a bond. For impressed current CP systems, the anode is not connected to the pipeline (i.e., no bond), but the anode is available for troubleshooting purposes. See page 2 of 10 of Exhibit A.

c. Insulated Joint – To be used at an insulated joint for verifying electrical isolation typically between CP and non-CP pipelines. See page 3 of 10 of Exhibit A.

d. Continuity Bond – To provide continuity between two structures. Typically used at insulators, so that the current bypasses an insulated joint, which allows the bond to be broken for troubleshooting purposes. See page 4 of 10 of Exhibit A.

e. Cased Crossing – To be used for verifying electrical isolation between casing and carrier pipe and cathodic protection, or if the casing and carrier pipe are protected as a single unit, it is used to verify continuity and cathodic protection. See page 5 of 10 of Exhibit A.

f. Stray Current Resistance Bond – Typically used to monitor and/or mitigate the effects of stray current between the Company's pipeline and a foreign structure. May include a stray current mitigation device (e.g., interference bond, continuity bond, anode). Refer to GS 1420.100 "Corrosion Control Design - Stray Current Control" and/or GS 1420.105 "Corrosion Control Design – Bonds" for additional guidance. See page 6 of 10 of Exhibit A. Consider installation of a long-life reference electrode in locations with foreign facilities that may add interference with CP readings. See Exhibit B.

g. Magnesium Anode Drain – Typically used to monitor and mitigate the effects of stray current when the owner of an interfering structure will not allow a bonded connection to their facility. The magnesium anodes provide a path for the interfering stray current to return to its source.

h. Line Current Flow (IR drop) – Typically used on galvanic anode CP systems to measure IR drop between two points on a pipeline for troubleshooting and/or design purposes. See page 8 of 10 of Exhibit A.

i. IR Drop Coupon – Typically used on galvanic anode CP systems to determine an "IR drop free" pipe-to-soil potential measurement in locations where a high IR drop environment is suspected. Refer to GS 1460.030 "Investigating Leaks on Coated Pipeline." See page 9 of 10 of Exhibit A.

j. AC Corridor – Test stations that are installed within AC interference areas shall be designed for personnel protection and pipeline protection. Dead front test stations shall be used within an AC corridor. Refer to GS 1420.120 "Controlling AC Interference" for additional guidance. See page 10 of 10 of Exhibit A.

Above ground test stations should be used when practical.

5. TEST STATION WIRING

A definitive, permanent wire coding system shall be used and recorded for all test stations within the Company's work management system or equivalent documentation. This may be accomplished by using different colored wire insulation, using color coded terminals, or by wrapping the wire with colored tape in the conduit head or test box.

Wire sizes shall be designated by local corrosion personnel. Wiring shall be a minimum size of AWG #12.

Examples of typical wiring diagrams for the basic types of test stations listed in Section 3 are shown in Exhibit A. Actual wiring diagrams shall be designated by local corrosion personnel.

6. LONG-LIFE REFERENCE ELECTRODE

A long-life reference electrode is typically installed for remote monitoring.

Another consideration for installing a long-life reference electrode is in locations with foreign facilities where interference may make it difficult to get an IR drop free CP reading. Long-life reference electrodes shall be installed in soil similar to the environment surrounding the pipeline.

Refer to Exhibit B for an example of an installation of a long-life reference electrode.

7. SAFETY

Test stations positioned near or under high voltage AC power lines shall be protected from potential shock hazards. The following are examples of protective measures:

a. voltage gradient mats, and/or

b. dead-front design of test station terminals.

Refer to GS 1420.120 “Controlling AC Influence” for additional guidance.

8. RECORDS

Existing Company forms shall be used to document the location and circuitry of test stations. In addition, each new test station installed or replaced shall be recorded and maintained within the Company’s work management system, or equivalent, for the life of the test station.

EXHIBIT A
(1 of 10)

Pipe-to-Soil Potential Test Station

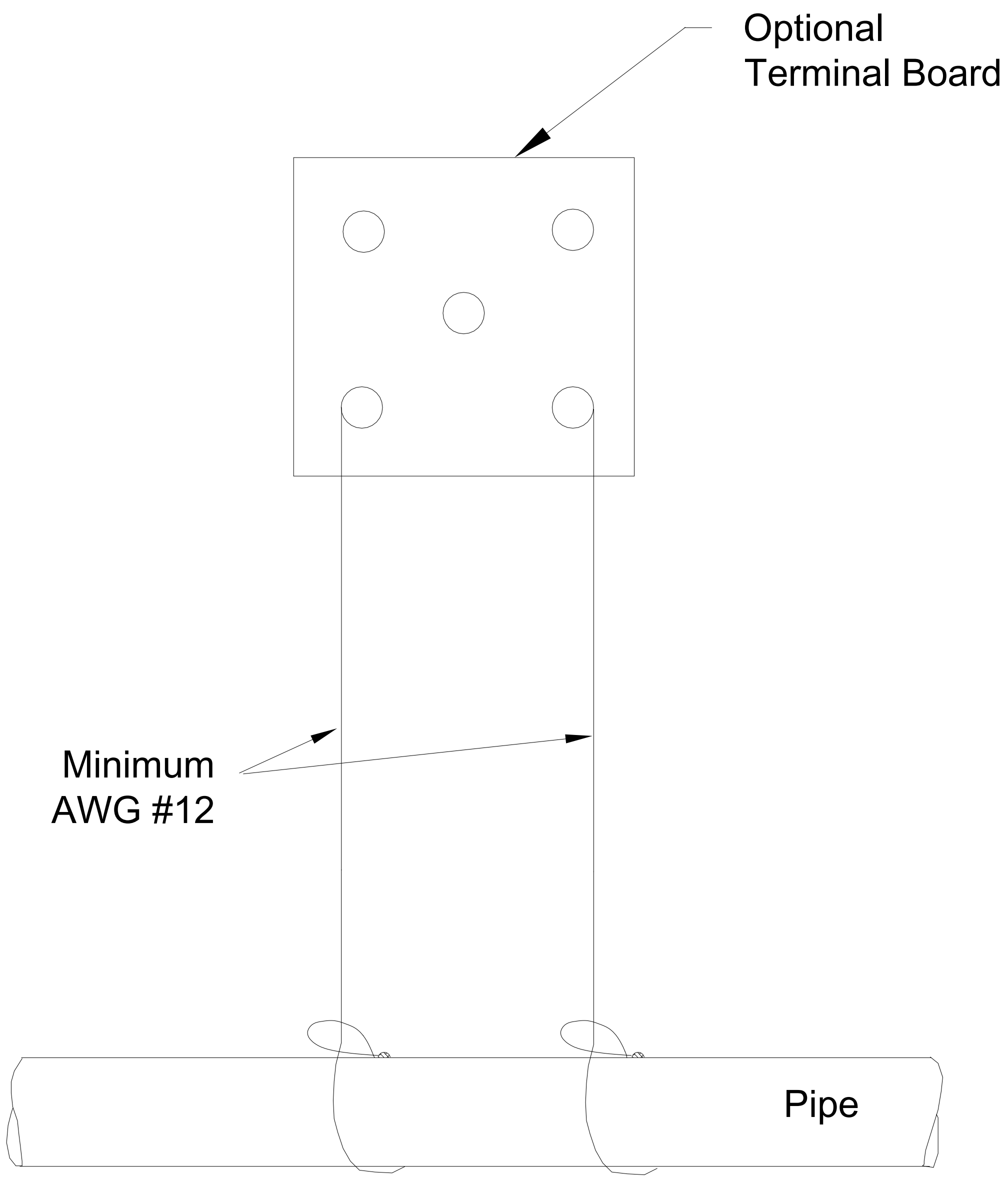

EXHIBIT A
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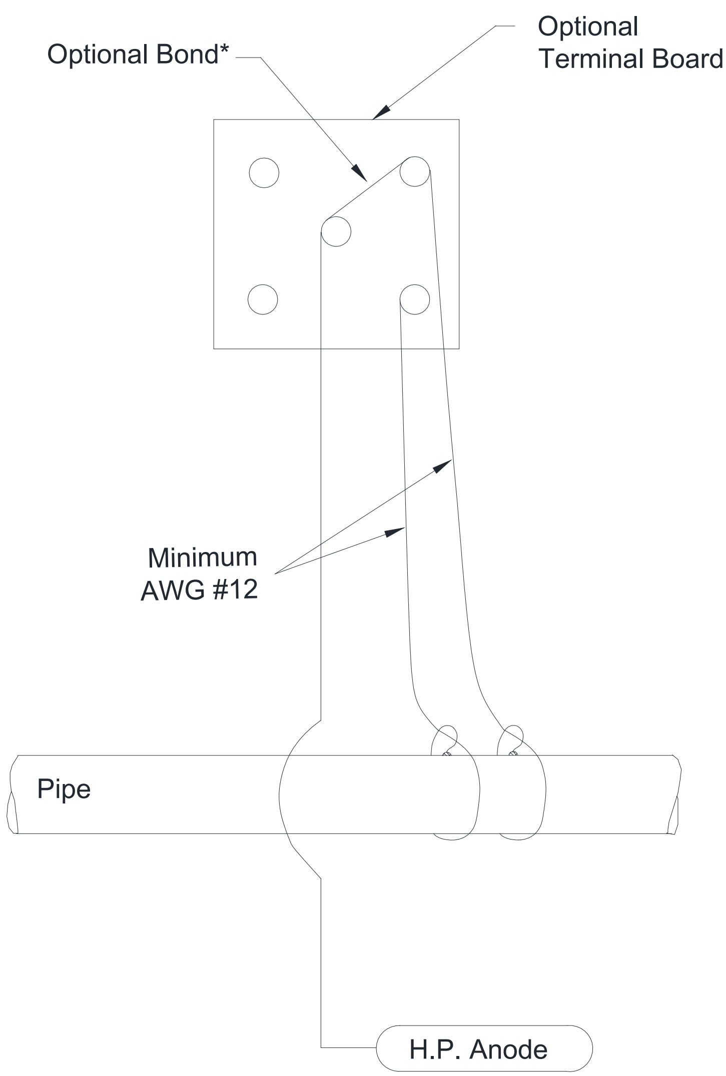
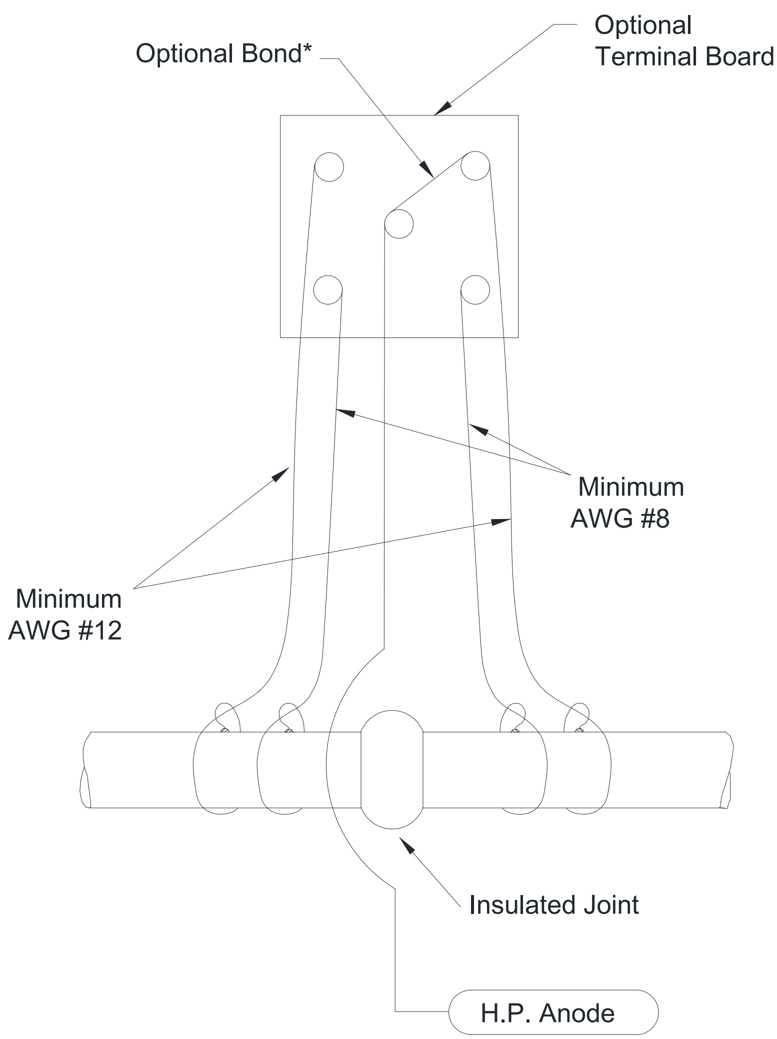
Magnesium Anode Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Optional Bond*: Install bond when anode is installed for CP purposes - typically on galvanic anode CP systems. Do not install bond when anode is installed for future troubleshooting purposes - typically on impressed current CP systems.

**EXHIBIT A
(3 of 10)**

Insulated Joint Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Optional Bond*: Install bond when anode is installed for CP purposes - typically on galvanic anode CP systems. Bond anode with pipeline side of insulator that has CP. Install two anodes if both sides have CP. Do not install bond when anode is installed for future troubleshooting purposes - typically on impressed current CP systems.

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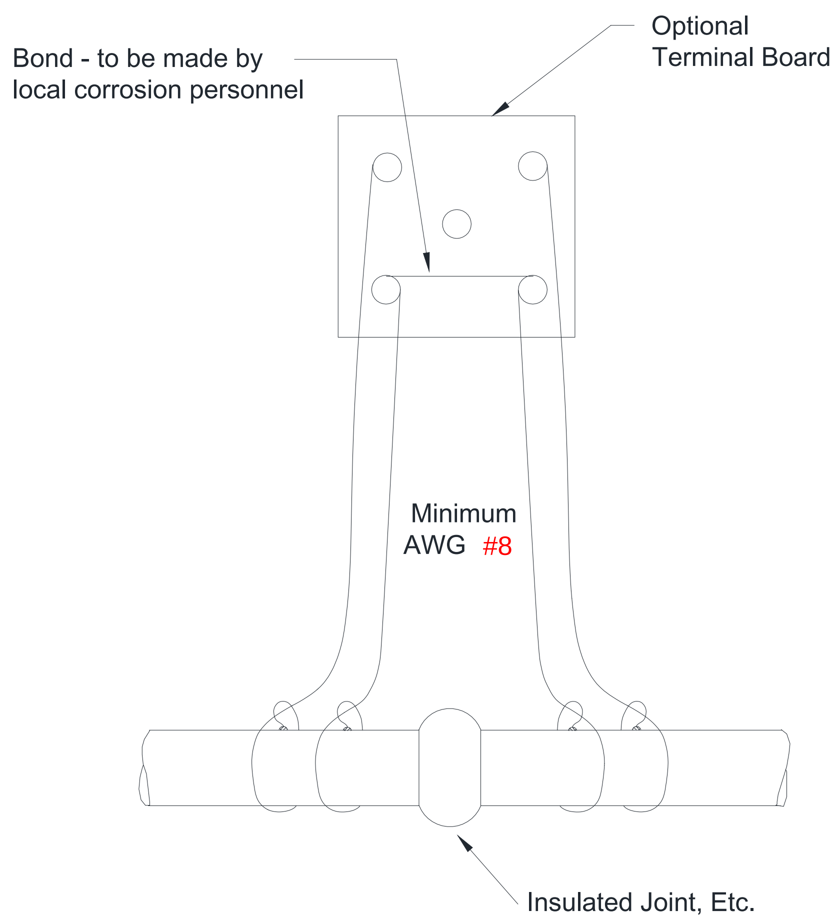
(4 of 10)

Continuity Bond Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Optional anode(s) may be installed. See Magnesium Anode Test Station (Exhibit A, 2 of 10).

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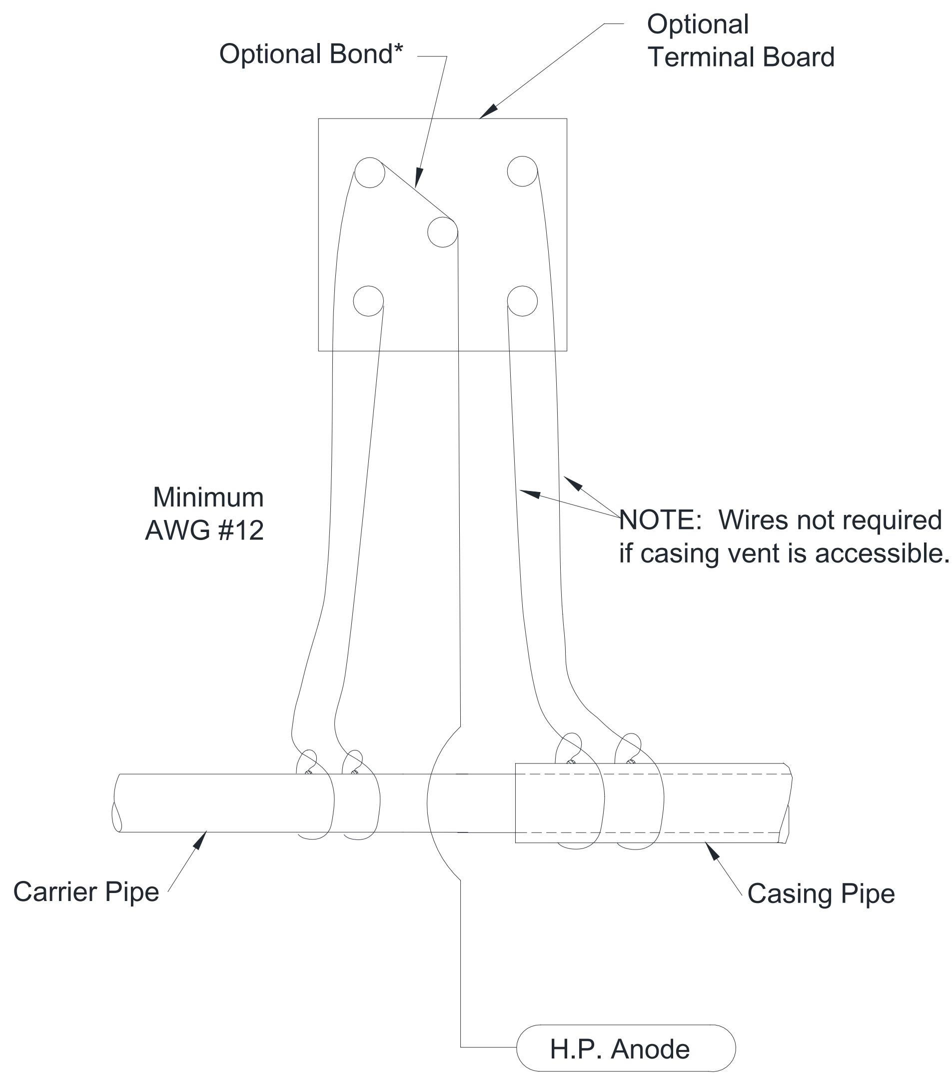
Cased Crossing Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Optional Bond*: Install bond when anode is installed for CP purposes - typically on galvanic anode CP systems. Do not install bond when anode is installed for future troubleshooting purposes - typically on impressed current CP systems.

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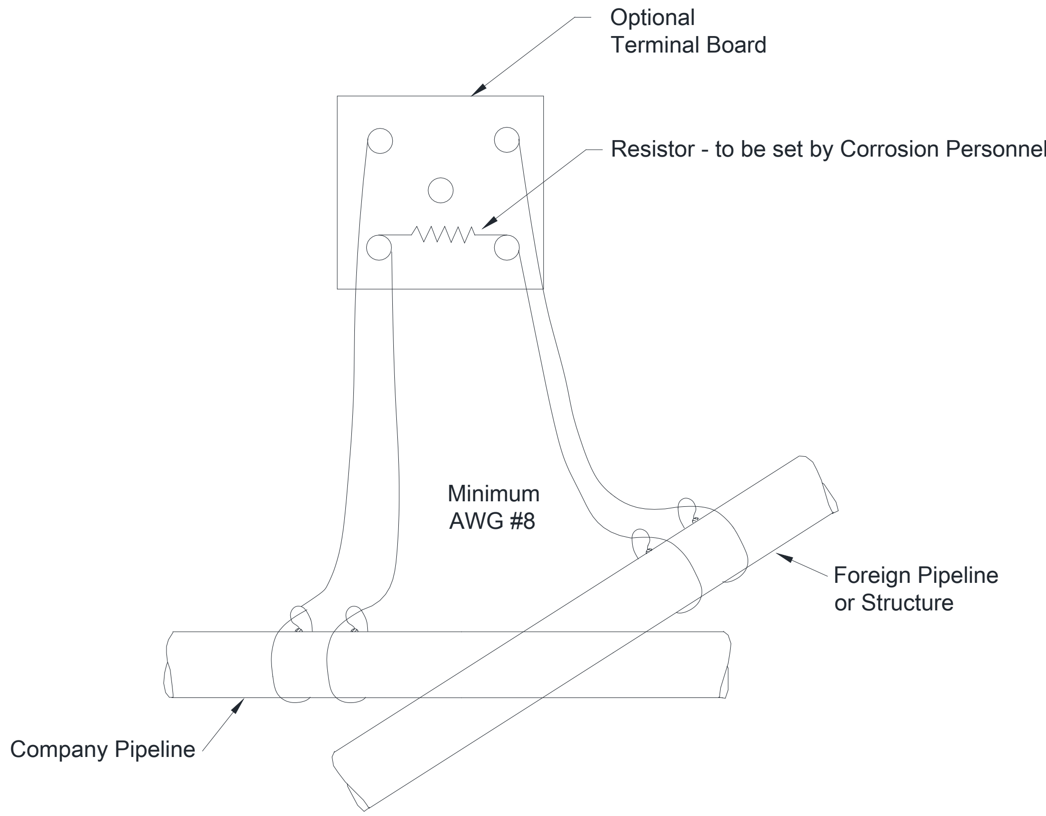
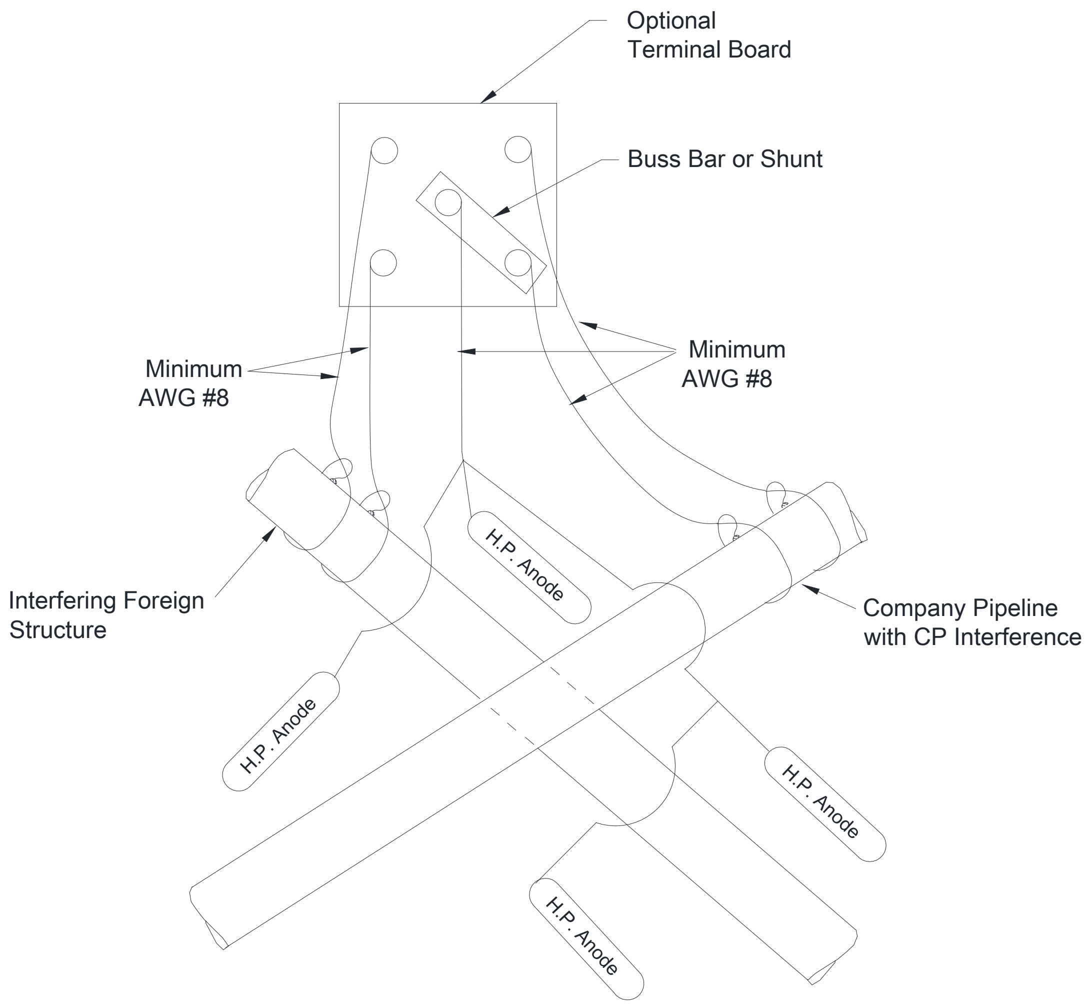
Stray Current Resistance Bond Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Consider installation of a long-life reference electrode in locations with foreign facilities that may add interference with CP readings. See Exhibit B.

EXHIBIT A
(7 of 10)

Magnesium Anode Drain Test Station



General Note: Follow a recorded wire coding or connection convention to identify wire function.

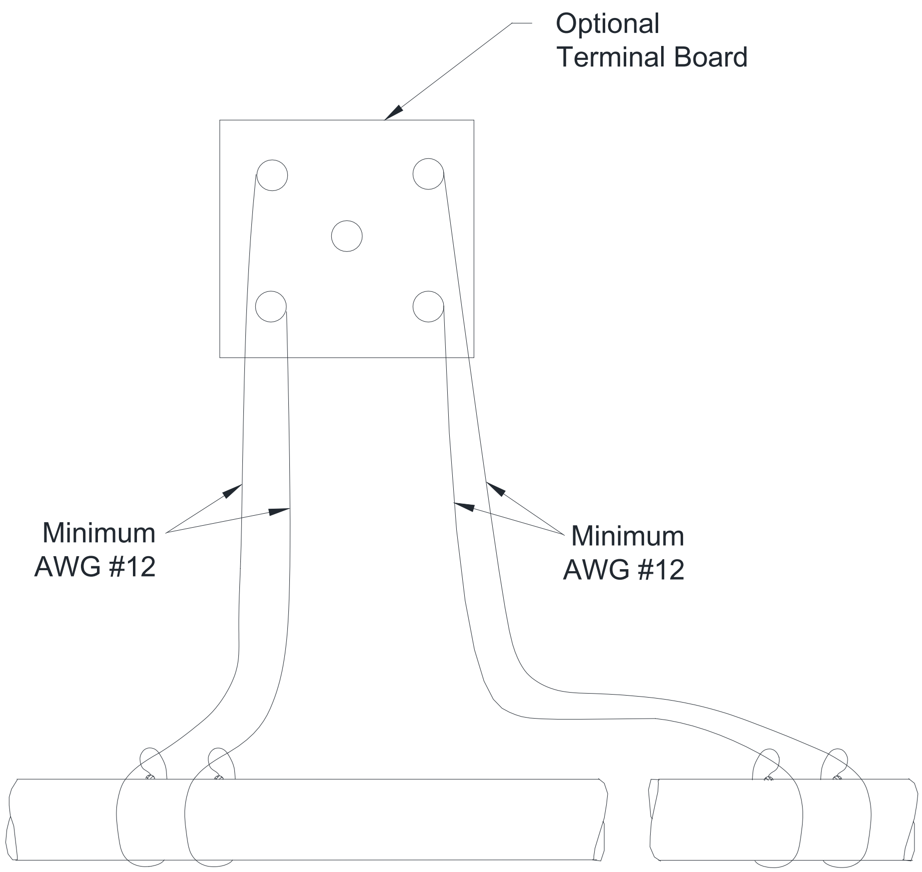
NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Corrosion Control Design – Test Stations**	Standard Number: **GS 1420.095**
Supersedes: 12/31/2012		Page 12 of 15

EXHIBIT A
(8 of 10)

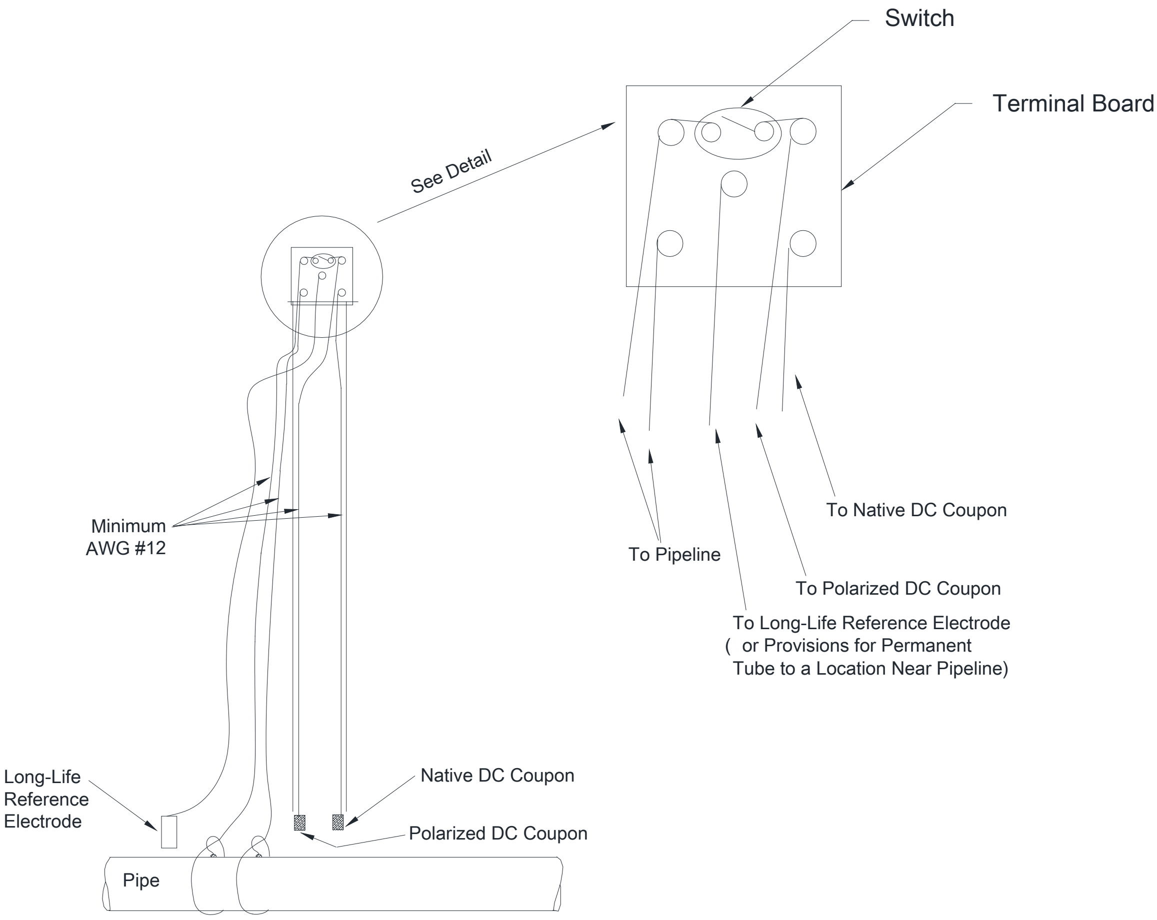
Line Current Flow (IR Drop) Test Station



General Notes:
- Record the length of pipe between the two sets of connections.
- Optional anode may be installed for instrument grounding. No connection to pipe.

**EXHIBIT A
(9 of 10)**

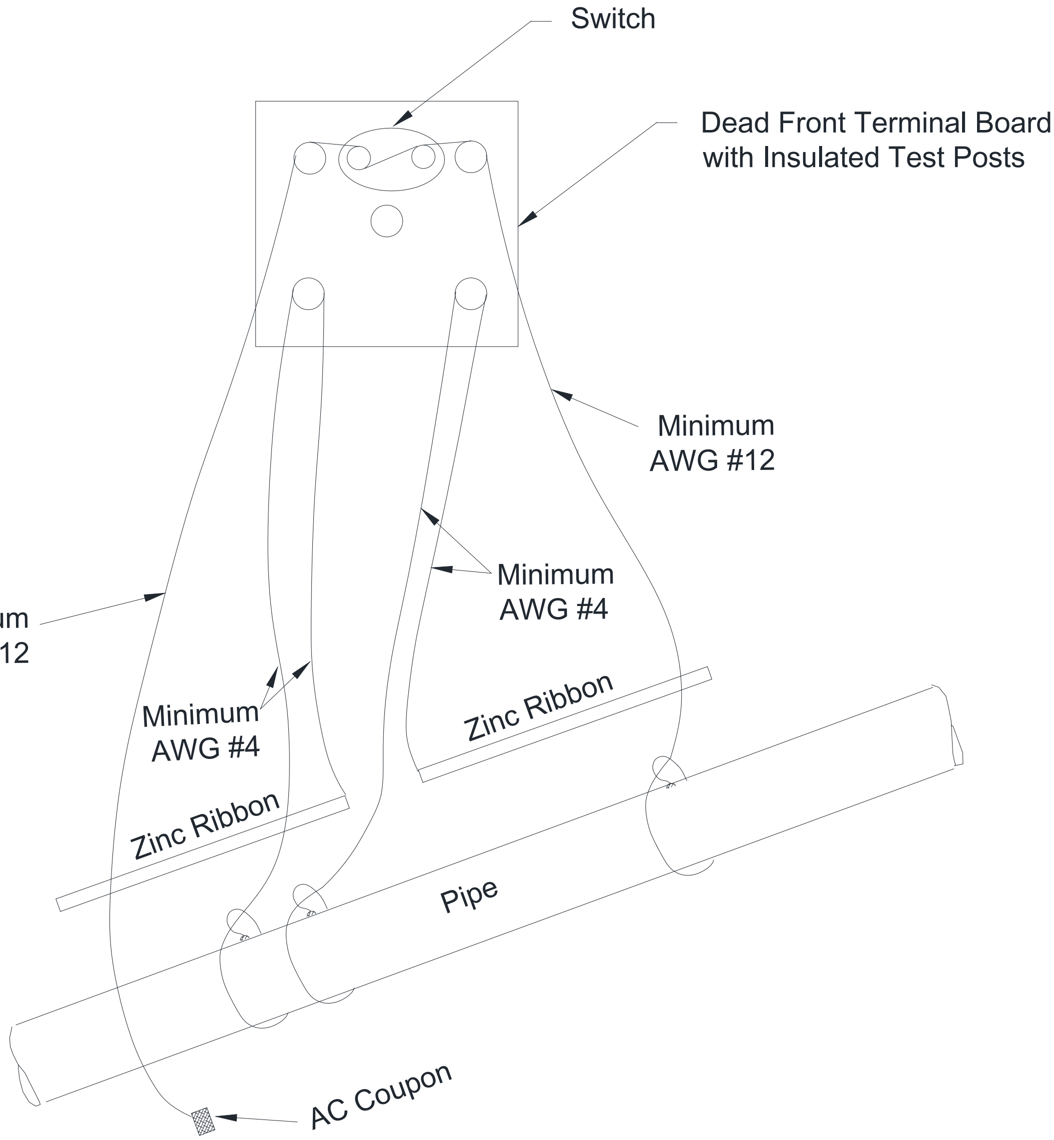
IR Drop Coupon Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Compact soil around coupon and long-life reference electrode (see Exhibit B) such that it is similar to existing soil environment around pipeline.
- An optional anode may be installed. See Magnesium Anode Test Station (Exhibit A, 2 of 10).

EXHIBIT A
(10 of 10)

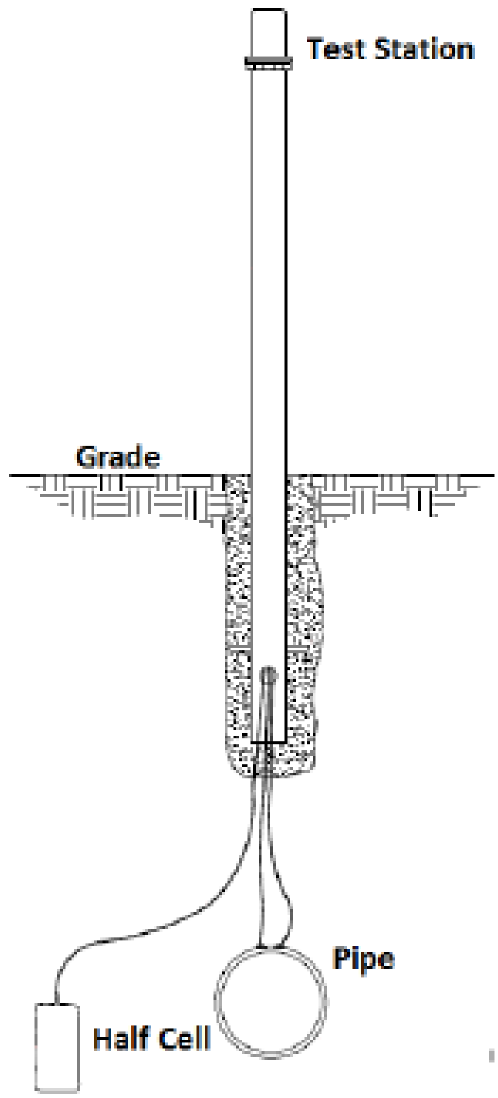
AC Corridor Test Station



General Notes:
- Follow a recorded wire coding or connection convention to identify wire function.
- Dead front test stations shall be used within an AC corridor for personnel protection.

EXHIBIT B

Long Life Reference Electrode



General Note: If installation on existing pipeline, do not dig/auger all the way to the pipeline. Long-life reference electrodes should see the same environment as the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Corrosion Control Design – DC Stray Current Control**	Standard Number: **GS 1420.100**
Supersedes: 05/01/2010		Page 1 of 12

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

This gas standard addresses testing and design to mitigate direct current (DC) stray current sources. Refer to GS 1420.120 "Controlling AC Interference" when dealing with alternating current (AC) interference.

Pipelines potentially subject to DC stray current are those in the proximity of grounded DC power sources, such as those common to operating coal mines, electrified railway systems, industrial plants, rectifiers, etc.

Where stray current is found to exist on a pipeline, bond all couplings for continuity, except specified insulated joints, to ensure electrical conductivity of the pipeline.

The magnitude and density of the current discharge to earth depends on such factors as:

a. the location of the pipeline with respect to the DC power source and its grounded conductor;

b. resistance of the soil;

c. conductivity of the pipeline; and

d. quality or lack of coating on the pipeline.

The return to static (natural) potential is the method that will be used by the Company and is the generally accepted method of other operators. Other methods of determining mitigation measures at the maximum exposure point are sometimes used by other companies and may be appropriate in some unique cases.

The method of control of interference problems is subject to agreement between the involved parties.

The Company shall be represented in the coordinating committee functioning in its operating area.

2. STATIC STRAY CURRENTS

Cathodic protection static stray currents essentially have a constant direct current output and are generated from impressed current type cathodic protection systems.

2.1 Detection

All corrosion control personnel should be alert to electrical or visual indications of cathodic protection interference currents from foreign structures. Some indicators are:

a. unusually high negative pipe-to-soil potentials;

b. unusually low negative or positive pipe-to-soil potentials;

c. depressed or lowered negative pipe-to-soil potentials adjacent to or at a foreign structure crossing or insulator;

d. evidence of localized corrosion pitting adjacent to or at a structure crossing or insulator;

e. knowledge of a rectifier type cathodic protection system on a structure which is adjacent to or crosses or parallels a Company pipeline;

f. changes in the line current magnitude or direction caused by the foreign DC source; and

g. damage to external coatings in a localized area near an anode bed or near any other source of stray direct current.

Figure 1 below shows different sources of static stray current interference.

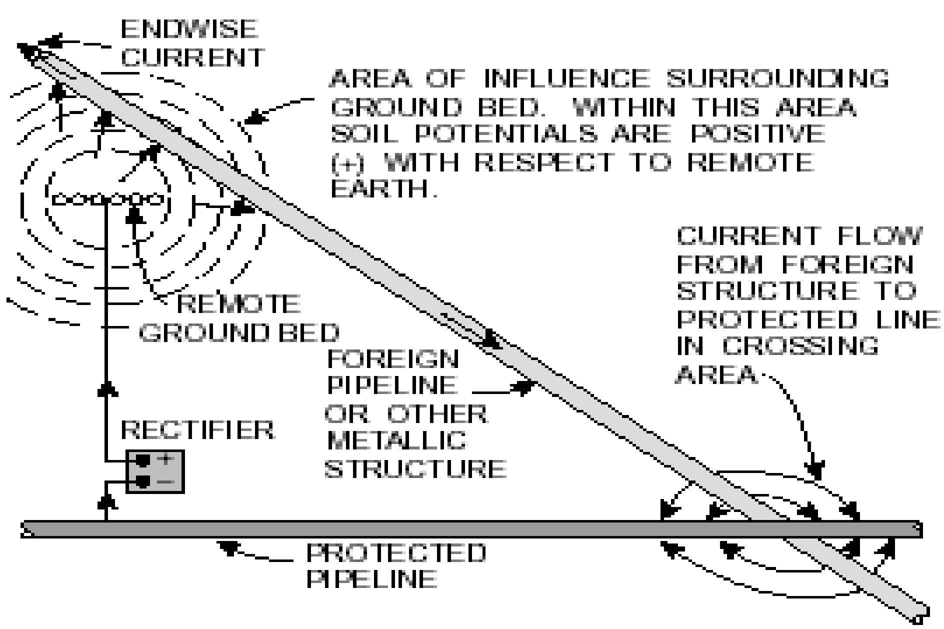


FIGURE 1: Gradients Promoting Interference

Information on existing or planned rectifier type cathodic protection systems may be obtained from other utility or pipeline companies through contact with their corrosion control personnel. This contact is normally made through the various corrosion coordinating committees functioning in most of the NiSource Energy Distribution operating area.

There are cases where this source of information is not sufficient. This may occur with applications of cathodic protection at building complexes, industrial plants, gasoline stations, river locks and dams, etc. These type applications are not always reported to the corrosion coordinating committees.

It should also be noted that there is no practical means to differentiate between stray current corrosion and normal galvanic corrosion by a study of the color or chemical makeup of the corrosion scale or by the pattern or shape of the corrosion pits.

2.2 Verification

When cathodic protection interference currents are suspected on a Company pipeline, tests shall be made to verify their existence, identify their source and determine if they are causing detrimental effects.

The method normally used to identify the source is to:

a. check with the owners of underground structures in the area to determine if any are protected with rectifiers;

b. obtain information from the local corrosion coordinating committee on cathodic protection rectifiers in the area; and

c. follow the suspected foreign structure's route and attempt to locate the existing rectifier installation.

After the suspected source of cathodic protection interference current is found, arrangements must be made to interrupt the rectifier and observe the effects on the Company pipeline.

Changes in pipe-to-soil or in line current readings which correlate with the interruption period indicate the source of interference current has been located.

Another method that may be used to determine the foreign structure that is causing the interference problem is through analysis of a pipe-to-soil potential survey of the Company pipeline. This method can also be helpful in those cases where efforts to have the rectifier interrupted are not successful with the foreign company. A plot of pipe-to-soil potential readings versus distance can reveal areas of stray current corrosion since a current discharge area is indicated by a "dip" to less negative (or positive) pipe-to-soil readings and a current pick-up area is indicated by a "rise" to more negative pipe-to-soil readings. In the normal case of cathodic protection interference, the pipe-to-soil potential survey will show a "dip" area (current discharge) with a "rise" area (current pick-up) above normal readings on each side of the dip.

Potential changes due to interference are more pronounced on well coated pipe than on bare or poorly coated pipe. Relatively small currents can cause large potential differences on well coated pipe, whereas on bare or poorly coated pipe relatively large currents may cause only small changes in potential.

2.3 Control

Cathodic protection interference from foreign structures may be mitigated with one or more of the following:

a. installation of a current drain bond (refer to GS 1420.105 “Corrosion Control Design – Bonds”),

b. coating the structures at the crossing (exposed area),

c. selected use of insulators,

d. the installation of magnesium anodes at the crossing orexposure area (e.g., magnesium anode drain),

e. adjustment of the current output from interfering CP,

f. relocation of the groundbeds of cathodic protection rectifiers can reduce or eliminate the pickup of interference currents on nearby structures,

g. rerouting of proposed pipelines may avoid sources of interference current, and/or

h. other methods that are useful to mitigate the discharge of current from the Company pipeline to the surrounding earth.

The interference current condition may be considered as mitigated when the pipe-to-soil potential at the maximum exposure points have been returned to their native (natural) potential or at least meet cathodic protection criteria (refer to GS 1420.020 “Cathodic Protection Criteria”)..

3. DYNAMIC (FLUCTUATING) STRAY CURRENTS

Fluctuating (dynamic) stray currents have a changing or variable current output due to a changing electrical load and are generated from a grounded DC power source such as motor-generators, or rectifiers used in railway systems, coal mine haulage systems, welding machines, DC pumps, etc.

3.1 Detection

Corrosion control personnel should be alert to indications of fluctuating (dynamic) stray current interference from foreign sources. The indications are obvious and are evidenced by rapid fluctuations in pipe current or pipe-to-soil potentials.

These rapid changes are typical indications of stray current from moving traction motors on street railway cars, as shown in Figure 5, or mine locomotives. These are usually complex systems that have more than one DC substation or generator at various locations. The electrical load provided by each substation varies with position of the streetcar or mine locomotive, condition of the rail bonds, and overall condition of the negative return system. Some miscellaneous sources, such as welding machines, DC lifting magnets, DC pumps, telemetering signals, etc., may have a more definite cyclic change.

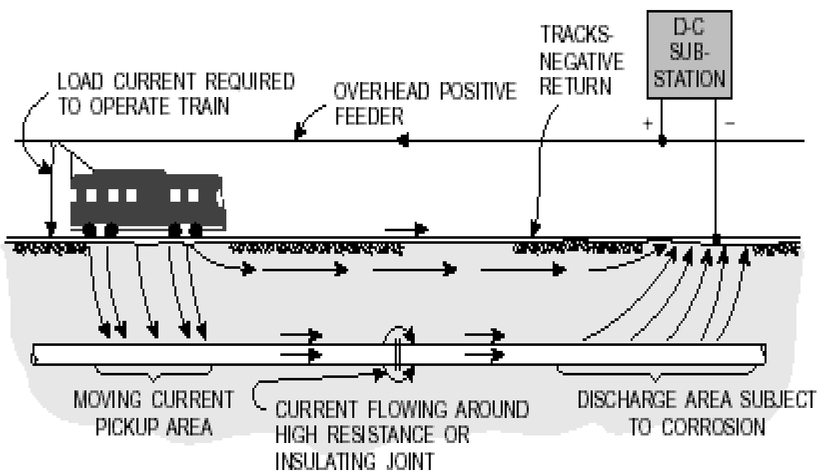


FIGURE 5: Example of Dynamic Stray Current Interference

Information on the probable existence of stray currents and DC power sources can be obtained from other utility or pipeline companies through contact with their corrosion control personnel. This contact is normally made through the various corrosion control personnel and through the various corrosion coordinating committees. Additional sources of information are Federal and State Department of Mines, and through engineering departments of mine, railway, and industrial companies.

3.2 Verification

In areas where fluctuating (dynamic) stray currents are suspected on a Company pipeline, tests shall be made to verify their existence and identify their source. Any one or combination of the following tests may be employed to verify stray current:

a. measurement of pipe-to-soil potentials of the Company pipeline with recording or indicating voltmeters,

b. measurement of magnitude and direction of current flow on the Company pipeline with recording or indicating instruments,

c. measurement of the variations in the current output of the suspected DC power source and observed correlation of these variations with the effects on pipe-to-soil potentials and current flow on the Company pipeline, and/or

d. interruption of the suspected DC power source concurrently observing the effects of pipe-to-soil potentials and current flow on the Company pipeline.

Refer to GS 1430.110 “Pipe-to-Soil Potential Measurements” and/or GS 1430.220 “Current Flow Measurements.”

Changes from normal to abnormal readings on any of these tests should show that stray current is present. Correlation obtained by tests "c" or "d" above will show the source of the fluctuating stray current.

Dynamic stray current anomalies are normally based on time frequency, which requires pipe to soil potentials to be monitored over a period of time with integration of multiple data outputs from different location points.

Locating the areas of exposure will generally show the source of the stray currents. The points of current discharge will usually be at crossings, adjacent to rails, DC generators or at other structures, such as pipelines tied to the DC power source ground system or negative.

3.3 Control

Stray current interference may be mitigated by one or more of the following methods:

a. prevention of current pick-up or limitation of the flow of stray current through the pipeline by selective use of insulators with control bonds;

b. counteraction of the stray current by means of increasing cathodic protection currents;

c. coating of the pipeline at crossings with other structures;

d. removal or relocation of the stray current source;

e. installation of a properly designed current drain bond(s) to the return (negative) side of the stray current power source, which may include the use of reverse current switch(es) or diode(s); and

f. decrease of the stray current leakage to earth by repairing rail bonds, adding copper return in the DC power negative circuit, etc.

A method for mitigating stray current corrosion problems is through the installation of metallic bonds between the pipeline and the negative return of the DC power source.

When a bond is used to control dynamic stray currents, it may be necessary to install a control device in the metallic bond to prevent reverse current flow through the bond. The control device that shall be used is a silicon diode or one of the commercially available silicon diode type reverse current switches. A reverse current switch must be used at each bond where the direction of current flow will change because of the varying intensity of the stray current.

The stray current condition may be considered controlled when the pipe-to-soil potential at each maximum exposure point has been returned to its static (natural) potential with bonds connected.

4. STRAY CURRENT MITIGATION DEVICES

The following lists several types of stray current mitigation devices that may be installed to control stray current. Refer to GS 1430.020 “External Corrosion Control Monitoring” for bi-monthly inspection and monitoring requirements for stray current mitigation devices.

4.1 Current Drain Bond

The installation of a current drain bond between the Company pipeline and the interfering structure is the Company’s preferred mitigation device. However, bonds to foreign structures shall not be made without obtaining permission from the owner of the structure. Refer to GS 1420.105 “Corrosion Control Design – Bonds” for additional guidance.

4.2 Magnesium Anode Drain

A magnesium anode drain is designed for installation at the location of the stray current discharge. The installation of magnesium anode(s) at this location will provide a pathway for interfering current to return to its source. See Exhibit A.

The number and size of magnesium anodes required will be based on the amount of current to be discharged. Anode life is greatly reduced when the anode is used for stray current drainage.

The mitigation of stray current by use of a magnesium anode drain must be tested for effectiveness on a frequent basis before placing it into service.

4.3 Reverse Current Switch

A reverse current switch is typically used in conjunction with a current drain bond for control of dynamic DC stray current to prevent DC current from flowing in the wrong direction. When the voltage differential between structures reaches a certain point, the switch will close. This permits the current to flow from the pipeline to the foreign structure through the bond cable instead of draining from the pipeline to soil and back to the foreign structure. By limiting the amount of current allowed to discharge from the pipeline, DC stray current corrosion can be mitigated. When the voltage differential between the pipeline and the foreign structure reaches zero mV DC, the switch will open.

Diodes are sometimes used in mitigating dynamic stray current. A diode is a fixed one-way current flow device.

5. NEW PIPELINE CATHODIC PROTECTION DESIGN

During the design phase of the cathodic protection design of a new pipeline, attention should be given to a new pipeline's physical location, particularly if the location may subject the pipeline to stray electrical currents from other facilities, such as the following:

a. other pipelines or utilities with associated cathodic protection systems,

b. rail transit systems,

c. mining or welding operations, and

d. induced currents from electrical transmission lines.

Local corrosion personnel should identify and plan for the mitigation and control of anticipated stray electrical currents prior to construction. Recommendations for the cathodic protection system for the new pipeline shall be communicated via Form GS 1420.010-1 “Transmittal of Corrosion Control Recommendations” or equivalent documentation.

As soon as practicable after construction of the new pipeline is completed, local corrosion personnel should implement monitoring, testing, and mitigation plans to control the effects of stray electrical currents.

6. RECORDS

Stray current mitigation devices shall be recorded in the Company’s work management system, or equivalent, for the life of the pipeline. Form GS 1420.100-1 “Stray Current Test and Mitigation Device Data” (Exhibit B), or equivalent documentation, can be used to document testing and design information, and should be filed in local corrosion records (e.g., circuit pack file), work management system, or mainline history file, as applicable. These records shall be kept for reference for the life of the pipeline.

Additional records that should be retained in local corrosion records include the scheduling of interference tests, correspondence with corrosion control coordinating committees, and direct communication with the concerned companies.

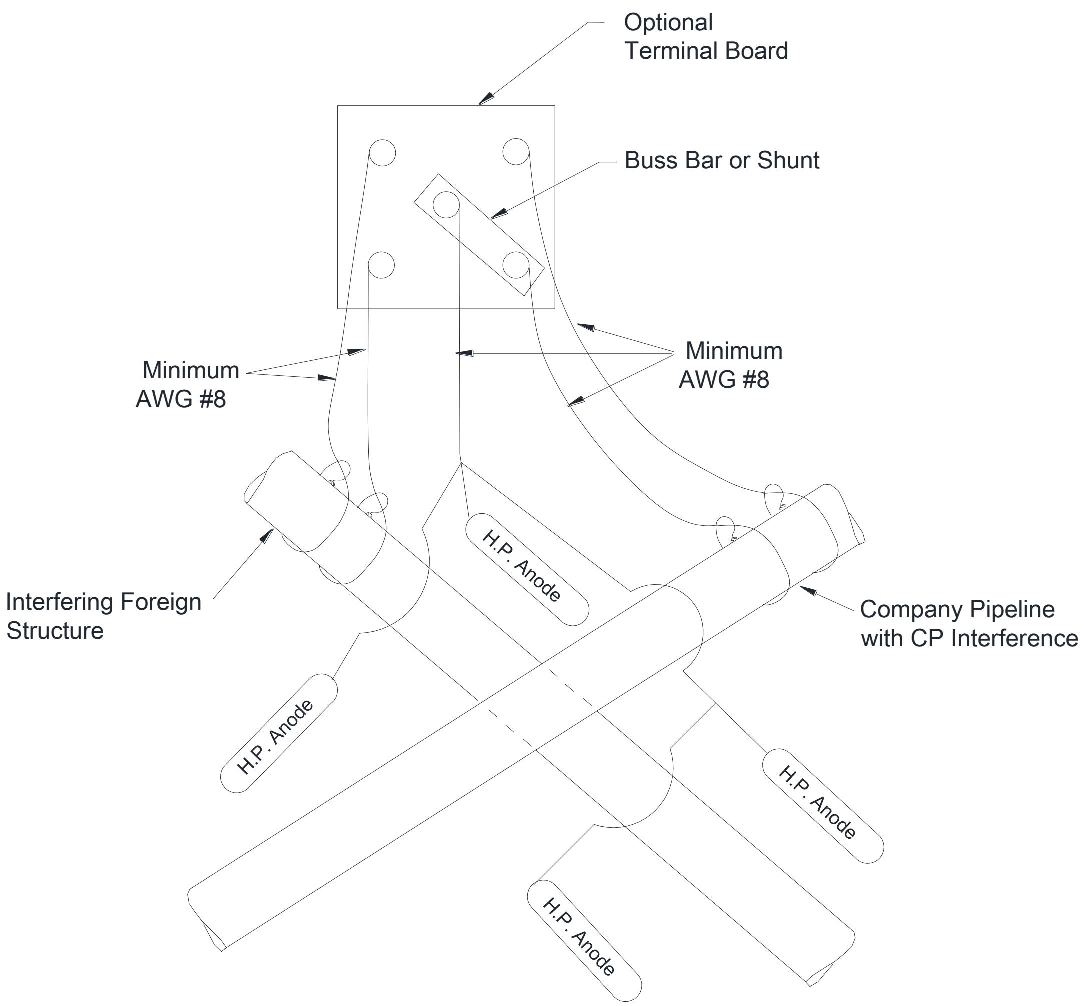
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Corrosion Control Design – DC Stray Current Control	Standard Number: GS 1420.100
Supersedes: 05/01/2010		Page 9 of 12

EXHIBIT A

Magnesium Anode Drain Test Station



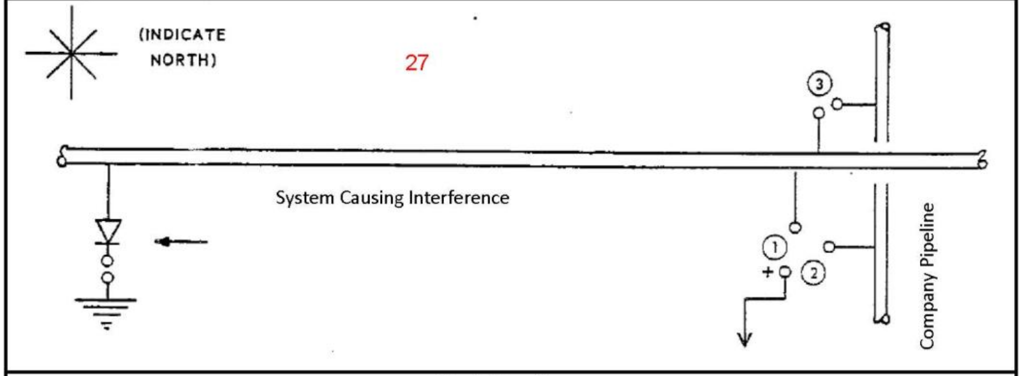
General Note: Follow a recorded wire coding or connection convention to identify wire function.

**EXHIBIT B
(1 of 3)**

Stray Current Test and Mitigation Device Data

Tested By: 1 Time: 2 Date: 3

Town: 4			Street: 5		
Between: 6			And:		
Approximate Location of Stray Current Area: 7					
Company Data	System Name/Number 8	Line Size 9	Coated ☐ Bare 10 ☐	Welded ☐ Screw 11 ☐ Coupled ☐	Map #: 12
	Remarks: 13				
Other Structure Data	Owner 14	Type 15	Representative 16 Present ☐ Not Present ☐		
Stray Current Source Data	Owner 17	Type 18	Output Reading 19 Volts Amps		
	Location: 20				
Test Station Data	Owner: 21	Number: 22	Wire Code: 23		
Interrupter Timing	"On" Period: 24		"Off" Period: 25		
Specific Location of Maximum Exposure	26				



Test Readings

Condition	Initial Data			Test Data				Final Data			
Reading Number	1	2	3	1	2	3	3	1	2	3	3
Unit	Volts	Volts	Volts	Volts	Volts	Volts	Amps	Volts	Volts	Volts	Amps
Current Off		28			29				30		
Current On		31			32				33		

Final Mitigation Device	Set By 34	Type 35	Resistance of Bond (if applicable): 36	Date 37
Remarks: 38				

Form GS 1420.100-1
(12/2012)

EXHIBIT B
(2 of 3)

Instructions for filling out
Form GS 1420.100-1 "Stray Current Test and Mitigation Device Data"

1 – Person performing test.

2 – Time of day.

3 – Date.

4 – Town or Township

5 – Street, road, highway or other location where test was performed.

6 – Two geographic locations that test area is between (e.g., streets, creeks, river, building, etc.).

7 – More specific description than Item 6.

8 – Piping system name or piping system number.

9 - Line size of Company's facility.

10- Check coated or bare – Company's facility.

11- Check welded, screw of coupled – how the pipeline is predominantly joined – Company facility.

12- Map number.

13- Additional remarks.

14- Owner of interfering structure.

15- Type of structure (e.g., 10" products line, gas line, telephone cable).

16- Other structure representative's name. Check present or not present.

17- Owner of current source.

18- Type of current source (e.g., rectifier, coal mine)

19- Output of current source; record both voltage and amperage.

EXHIBIT B
(3 of 3)

Instructions for filling out
Form GS 1420.100-1 "Stray Current Test and Mitigation Device Data" (continued)

20- Location of current source.

21- Test station owner.

22- Test station number.

23- Test station wiring code information.

24- Interrupter "On" interval.

25- Interrupter "Off" interval.

26- Specific location of maximum exposure point.

27- Indicate north and any notes regarding field observations.

28- Reading 1, 2, and 3 – Initial data (static condition) and current source off.

29- Reading 1, 2, and 3 – No bond and current source on.

30- Reading 1, 2, and 3 – With test bond and current source off.

31- Reading 1, 2, and 3 – With test bond and current source on.

32- Reading 1, 2, and 3 – With final bond and current source off.

33- Reading 1, 2, and 3 – With final bond and current source on.

34- Company personnel that sets final bond.

35- Type of mitigation device (e.g., interference, reverse current switch, diode, magnesium anode drain, nichrome wire, variable resistance, rheostat).

36- Resistance of bond (if applicable).

37- Date final bond was set.

38- Additional remarks.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Corrosion Control Design – Bonds	Standard Number: **GS 1420.105**
Supersedes: 05/01/2010		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Bonds shall be made only at the request of corrosion personnel or after approval from corrosion personnel.

A minimum size #8 insulated AWG wire should be used for bonds made in an impressed current system, stray current areas, or interference bonds. A #12 insulated AWG wire is usually sufficient for all other bonds. Larger bond wires may be necessary in stray current areas (e.g., mining areas, street car railway systems).

Refer to GS 1420.100 “Corrosion Control Design – Stray Current Control” for additional guidance regarding the design of bonds to control stray current areas.

2. CONTINUITY BONDS

A continuity bond is a metallic connection made to provide electrical continuity between structures that can conduct electricity.

Continuity bonds are typically installed around high resistance pipe joints such as compression type couplings to maintain electrical continuity within a cathodic protection (CP) system (i.e., CP circuit).

A means of electrical continuity must be provided for all non-insulating type couplings installed on steel main. Those coupling types that are electrically conductive through incorporation of armored gaskets or internal contacts typically do not require installation of a continuity bond.

3. DRAINAGE (INTERFERENCE) BONDS

A current drainage (interference) bond is a metallic connection designed to provide for control of electrical current interchange between pipelines or between sections of a pipeline. The purpose of a current drainage bond is to provide a metallic path for direct current (DC) so that it may return to its negative power source.

Bonds to foreign structures shall not be made without obtaining permission from the owner of the structure. The physical connections shall be made by the owner unless the owner specifically requests the Company to make the connection.

4. DESIGN OF A DRAINAGE BOND

The most important consideration in the selection of drainage points is that the structure experiencing interference must be electrically continuous from the point of maximum exposure to the current drain bond, and that the structure causing the interference is electrically continuous from the current drain bond to the negative DC power source.

The drainage point should be at, or as close as practical to, the maximum exposure point. Consideration must also be given to the installation cost (e.g., length and size of bond cable required, availability of right-of-way, existing paving).

Stray current drainage bonds shall be designed to drain sufficient current from the Company pipeline to the interfering structure or power source negative so that the pipe-to-soil potential of the Company pipeline at its maximum exposure point (and during the maximum exposure time in the case of fluctuating strays) is returned to its static (natural) potential. This return potential is measured with the bond connected and the DC power source on.

The attachment of electrical bonds can reduce the level of CP on the interfering structure. Supplemental CP may then be required on the interfering structure to compensate for this effect.

A bond may not effectively mitigate the interference problem in the case of a cathodically protected bare or poorly externally coated pipeline that is causing interference on an externally coated pipeline. If this is the case, then other stray current control measures may need to be completed in conjunction with a bond or instead of a bond. Refer to GS 1420.100 “Corrosion Control Design – Stray Current Control.”

4.1 Bonding Cable Size

The bond cable must have sufficient conductance to drain the required current. Care must be exercised to avoid over-draining since heavy drainage may increase interference with other structures, and large negative potentials may deteriorate pipe coatings, as well as exposing lead sheathed cables or lead water lines to cathodic corrosion action.

If wires of sufficient conductivity are already available, a variable resistance of proper current rating may be inserted between the leads to each structure and adjusted until the pipe-to-soil potential at the maximum exposure point is returned to its static (natural) potential with the DC power source on.

In those cases where wires of sufficient conductance are not readily available, the required bond current, bond resistance, and required wire size can be determined by the following suggested method.

a. Locate the source of the stray current and determine the maximum exposure point. Refer to GS 1430.240 "Interference Tests" for guidance on how to perform this test.

b. Determine the most positive (least negative) pipe-to-soil potential at the maximum exposure point.

c. Establish a temporary bond (minimum #8 AWG wire) with a slide resistor or rheostat between the pipeline and its source of interference. (Two wires or contact points must be available on the pipe experiencing interference. Do not take pipe-to-soil readings on a wire that is conducting current.)

d. Interrupt the impressed current system protecting the interfering structure with a suggested "on" cycle twice as long as the "off" cycle (to differentiate between the two cycles and to avoid polarization decay of the interfering structure).

e. Measure the difference of the pipe to soil potentials (ΔE) at the maximum exposure area over the Company pipeline during the "on" and "off" cycles.

f. Interrupt the impressed current system protecting the interfering structure. A suggested starting point is with the resistance set at half of its value. If the Company pipeline is being depressed, decrease the resistance. If the Company pipeline is being impressed, increase the resistance. Continue adjusting the resistance so that the pipe to soil potential readings during the "on" and "off" cycles are the same (i.e., ΔE equal to zero). If ΔE cannot reach zero exactly, set the resistor so that ΔE is as close to zero as possible with the Company pipeline impressed with current.

g. Create a permanent bond by re-establishing the same resistance and current drain as the temporary bond. If the location of the temporary bond is different than the permanent bond, consider the cable resistance. The resistance per 1000 feet of a copper cable is given in Table 1 below.

h. Document resistance value and current drain.

Table 1

Data Relating to Copper Conductor Wire (Insulated)					
AWG Gauge #	**# of Wires in Strand**	**Diameter (Bare) Inches**	**Resistance Per 1000 Ft. @ 68°F**	**Amps Per MV Per Foot**	**Current Capacity (Amperes)**
0000	19	0.5277	0.04997	20.050	195
000	19	0.4700	0.06293	15.900	165
00	7	0.4134	0.07935	12.620	145
0	7	0.3684	0.10007	10.000	125
1	7	0.3279	0.12617	7.930	110
2	7	0.2919	0.15725	6.360	95
3	7	0.2601	0.19827	5.050	80
4	7	0.2316	0.25000	4.000	70
6	7	0.1836	0.39767	2.520	55
8	7	0.1458	0.52585	1.600	40

In all cases, the final conditions at the maximum exposure points must be checked after the drainage bond installation to determine if the return potentials are satisfactory.

4.2 Bonds to Control Dynamic Stray Current

For dynamic stray current situations, extensive testing for a 24-hour period of time with a data logging recording device to monitor stray current and to determine the depressed areas may be necessary. This is often the case in street railway or mining stray current problems. In most cases, large amounts of currents are returned; therefore larger bond wires (e.g., #4 AWG) are used. Review the ΔE readings taken on the pipe from the 24-hour recording device to determine the size of the temporary bond wire. A small bond wire could overheat or burn out. In addition, a diode or a reverse current switch will typically be used to prevent loss of cathodic protection on the Company pipeline when stray current is not present.

4.3 Bonds to Mitigate Multiple Interference Areas

Some cathodic protection interference problems involve multiple bonds between structures and multiple DC power sources. As pointed out, the bonds or the power source may not only affect the structure being drained but may affect other structures as well. The simplest way to handle a system involving several bonds is to design each bond on an individual basis and after all have been installed, conduct tests on all of the structures involved. Resistance of one or more of the bonds may require adjustments to satisfy all parties involved.

4.4 Additional Bonding Cable Specifications

Insulated stranded copper wire of sufficient conductivity and current rating shall be used for all current drain bonds. All bond resistors or nichrome wire used shall have a current and wattage rating that will handle the peak current drain without overheating or burning out. Wattage and current ratings of all parts may not be exceeded. For current ratings of the bond wire, see Table 1 above. Check wattage requirements for the resistor by the following formula:

$$P = I \times E$$

Where: P = Power (watts),
I = Current (amperes), and
E = voltage (volts).

Drainage wires that are suspended in air and could contact another metallic or power facility shall be protected by fuses at the pipe end of the wire.

Drainage wires shall be installed through a test station. A means shall be provided so that current measurements may be taken without breaking the circuit. Calibrated shunts of the proper rating may be installed where current testing is to be done on a frequent basis. A suggested best practice is to install a 0.001 ohm shunt, which represents a 1:1 ratio (i.e., 1 mV = 1 amp). In addition, a convenient means of opening the circuit shall be provided. See GS 1420.095 “Corrosion Control Design - Test Stations” for a typical test station wire diagram for a bond.

5. RECORDS

Form GS 1420.100-1 “Stray Current Test and Mitigation Device Data” (refer to GS 1420.100 “Corrosion Control Design – Stray Current Control”), or equivalent documentation, shall be used to document the location and circuitry of new and replaced drainage (interference) bonds. In addition, each drainage (interference) bond shall be recorded and maintained within the Company’s work management system, or equivalent.

Continuity bonds between otherwise isolated facilities or isolated sections of pipeline bonded through a test station should be recorded in the Company’s work management system for future adjustments and troubleshooting.

Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Internal Corrosion Design Guidelines for Transmission Lines	Standard Number: GS 1420.110
Supersedes: 03/01/2008		Page 1 of 9

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.476

1. GENERAL

Unless it is determined to be impracticable or unnecessary, each new or replaced **transmission line** shall be designed to:

a. reduce the risk that liquids will collect in the pipeline,

b. have effective liquid removal features whenever the configuration would allow corrosive liquids to collect, and

c. allow for the use of corrosion monitoring devices at locations with significant potential for internal corrosion.

When the configuration of a transmission line is changed, the Company must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

Typically, the gas delivered to the Company is considered to be dry and non-corrosive. Dry gas is defined as gas above its dew point and without condensed liquids. If liquid water is not present in the steel pipeline, corrosion will not occur. The corrosive liquids referred to in this gas standard pertain only to liquids that act as an electrolyte (e.g., liquid water). Other liquids, such as hydrocarbon drip or compressor oils that do not contain liquid water, do not impact the potential for internal corrosion.

Certain constituents in the gas (e.g., carbon dioxide, hydrogen sulfide) might affect whether a corrosion condition exists, and therefore must also be considered when following the requirements of this gas standard. Refer to GS 2910.010 “Gas Supply – Gas Quality Specifications” for acceptable limits of natural gas constituents (i.e., components).

2. DETERMINATION OF WHAT CONSTITUTES IMPRACTICABLE OR UNNECESSARY

First, it must be determined if it is impracticable or unnecessary to design and construct features to reduce the risk of internal corrosion in a new or replaced transmission line. The following sections provide examples to assist in this determination.

2.1 Impracticable

Some situations may make it impracticable to design and construct features to reduce the risk of internal corrosion. For most of these situations, the installation of liquid removal or monitoring devices at an upstream location feasible for installation should be considered, if it does not already exist. Below are examples of these types of situations:

a. a low spot or angle created when a pipeline segment is bored in and where liquid water is expected to accumulate,

b. pipeline segments installed in casings in such a configuration that liquid water is expected to accumulate,

c. water crossings or where pipeline segments are installed in marshes,

d. very deep pipelines or pipelines in extremely congested rights-of-way installed in a configuration where liquid water is expected to accumulate, and

e. changes to compressor, meter, and regulator station facilities where there is limited space and access.

2.2 Unnecessary

Examples of conditions that may make it unnecessary to design and construct features to reduce the risk of internal corrosion include the following.

a. Vaporized LNG is transported where no other source of supply or interconnect exists. This gas is very dry and is extremely unlikely to produce internal corrosion.

b. Chemicals (e.g., corrosion inhibitors, biocides) are used to mitigate the occurrence of internal corrosion.

c. Moisture analyzers or liquid water removal devices exist upstream of the pipeline segment to monitor for liquid water.

d. Gas quality is monitored upstream of the pipeline segment, provided that short-term upsets would be detected and managed.

e. The project consists of in-kind replacement of pipe, valve, fitting, or other line components with no known internal corrosion with like size and like configuration. For example, replacement of a small section of 24-inch pipe with 24-inch pipe, or replacement of a full-port ball valve with a full-port ball valve.

f. The project consists of additions to meter stations or regulating stations, such as an additional meter run or addition of a relief valve.

g. The project consists of the installation of pipe with no inclination angles exceeding the critical angle. Refer to IMP 6-15 “Internal Corrosion Direct

Assessment Plan" for the formula to determine the critical angle.

h. The purpose of the pipeline is for a temporary operating period of service not to exceed 5 years beyond installation, provided that the corrosion rate would not achieve a predicted failure pressure (PFP) below operating pressure in that time period.

i. The pipeline is planned for a normally dry gas system where short-term upsets would blend with a sufficient volume of dry gas to make the risk of internal corrosion negligible (e.g., buried below the frost line and away from large temperature differentials).

j. The pipeline contains no in-line pressure reducing devices that would precipitate the fall-out of liquid water into the pipe segment.

3. DESIGN OF NEW AND REPLACEMENT TRANSMISSION LINES

There are several design features that the Company may incorporate to reduce the risk of corrosive liquids collected in a line (see Section 3.1 below). However, if the design configuration still allows corrosive liquids to collect, then liquid removal devices and/or internal monitoring are required (see Section 3.2 below).

3.1 Pipeline Configuration Design

The following are examples of design features that will reduce the risk of liquids collected in a line.

a. Minimize dead ends, such as pipe stubs downstream of stopple fittings, and low areas.

b. Design the pipeline with no critical angles of inclination at normal operating conditions so that liquid water cannot accumulate and gas velocity cannot overcome gravity. The critical angle calculation depends on gas pressure, velocity, temperature, charactersitics, and pipe diameter. The formula can be found in the IMP-6-15 "Internal Corrosion Direct Assessment Plan."

c. Minimize aerial crossings, since these can result in variation of temperature and may cause liquids to separate from the flow.

d. Design for turbulent flow, in which the velocity at a given point varies erratically in magnitude and direction, to decrease the chance of liquid water separating from the flow stream and accumulating.

e. Design diameter changes to provide a smooth hydraulic transition, thereby eliminating pockets of altered flow velocity where liquids could collect.

f. Design a pipeline to minimize entry of water, other liquids and corrosive gases at receipt locations. For example, liquid water removal devices (e.g., separators, dehydration systems) at the inlet to compressor, meter, and regulator stations can protect station piping from the entry of liquid water.

g. Design for the injection of corrosion inhibitors.

h. Design a pipeline to allow the use of cleaning pigs and instrumented internal inspection devices (e.g., replaced valve must be full-opening; include pig launcher/receiver; limit internal diameter changes, probes, small diameters that don't accommodate a cleaning pig, heavy wall pipe, short radius bends less than 3D).

i. Maintain a flow velocity sufficient to prevent corrosive liquids from dropping out of the gas stream.

j. Evaluate the seasonal nature of delivery and capacity patterns and design to avoid no-flow or low-flow conditions.

k. Provide slam valves to isolate systems where corrosive gas is expected.

l. On new pipelines with new receipt meters, design the configuration at the point of delivery (i.e., gate station) to accommodate equipment to monitor moisture and gas quality with control systems, such as slam valves or secondary liquid separation or dehydration equipment.

m. Include equipment to evaluate gas quality characteristics (e.g., water, carbon dioxide, hydrogen sulfide, oxygen).

n. Provide for blending, such that liquid water will be reabsorbed into the gas stream where there is potential for liquid water to enter the line during upset conditions.

3.2 Required Liquid Removal Devices or Internal Corrosion Monitoring

If the design configuration would allow liquid water to collect, the design for effective liquid water removal is required and monitoring for internal corrosion would not be required, provided a program for liquid water removal is instituted. Where corrosive liquids are likely to collect, and a liquid removal system is not provided or does not effectively remove corrosive liquids, and there is significant potential for internal corrosion, devices for monitoring internal corrosion are required.

3.2.1 Liquid Removal Devices

Review existing equipment and/or design new equipment (e.g., scrubbers, filter separators, drips) to allow liquid water removal and sampling at key areas (e.g., low spots, no-flow points, dead ends, sags, bases of inclines, valves, manifolds, pig traps).

If liquid removal devices are planned for installation, a liquid removal management program must be instituted. Refer to Section 5 below.

3.2.2 Internal Corrosion Monitoring

Refer to GS 1440.020 "Internal Corrosion Monitoring" for guidance and requirements for internal corrosion monitoring.

4. CHANGES TO THE CONFIGURATION OF AN EXISTING TRANSMISSION LINE

If a change to the configuration of a transmission line increases the risk for internal corrosion on the downstream transmission line, consideration shall also be given to installing liquid removal devices and internal corrosion monitoring devices, as appropriate. The following are provided as examples of changes to configuration:

a. a physical change that would compromise the effectiveness of existing liquid removal features downstream (e.g., reversing flow, removal or bypassing of drips, launchers, or receivers, diameter changes, installation of sharp radius bends or other changes that would make a piggable line no longer piggable);

b. adding potential sources of corrosive liquids to a system that would create a significant potential for internal corrosion, and therefore require changes in downstream monitoring locations;

c. abandonment, removal from service or isolation of a segment of pipeline; and

d. changes that would affect existing downstream internal corrosion mitigation systems (e.g., extending a pipeline in length, changes to diameter for significant length).

5. DESIGN RESPONSIBILITIES

The design requirements of this gas standard are a joint responsibility between engineering and corrosion departments.

5.1 Gas Systems Design Engineer

The engineer responsible for the design of a new or replaced transmission line shall review the project with the personnel responsible for managing the Company's Integrity Management Program for input during the design phase. The engineer shall complete Form GS 1420.110-1 "Internal Corrosion Risk Assessment" (see Exhibit A), and review all supporting information to finalize the pipeline design.

The engineer should review the operations maps for existing equipment, review the internal corrosion history on existing pipelines within the project area, and inquire about local gas quality issues.

The engineer should identify on the design drawings or sketch the location(s) where the potential for liquid accumulation is suspected.

After compiling information regarding the factors affecting the pipeline design, Form GS 1420.110-1 "Internal Corrosion Risk Assessment," shall be forwarded to the corrosion front line leader/supervisor for review and input.

Refer to Exhibits B and C for the decision processes regarding the Design of New and Replacement Transmission Lines.

5.2 Corrosion Front Line Leader/Supervisor

The corrosion front line leader/supervisor should review the design drawings or sketch and Form GS 1420.110-1 “Internal Corrosion Risk Assessment,” and along with typical corrosion recommendations, provide feedback as to the internal corrosion history, the location and type of fittings recommended to monitor for internal corrosion as necessary, and input for the Internal Corrosion Risk Assessment.

If liquid removal systems are included in the design, the corrosion front line leader/supervisor shall inform the local leadership team that a liquid management program, that includes liquid removal, sampling, pigging/sweeping, and/or blowing drips, must be planned and implemented.

6. RECORDS

The completed Form GS 1420.110-1 “Internal Corrosion Risk Assessment” and design drawings shall be filed with the appropriate work order completion records and the Pipeline Integrity files. As-built drawings showing that the design specifications were followed shall also be filed with the work order completion records. These records shall be kept as long as the pipeline remains in service.

EXHIBIT A

INTERNAL CORROSION RISK ASSESSMENT

Project Name:	Work Order:
Transmission Line:	Assessment Date:
Location:	
FACTORS AFFECTING THE PIPELINE DESIGN	
Scope of the Project:	
Critical Angle of Inclination: Indicate area(s) of concern on the attached design drawings or sketch.	
Location of Existing Liquid Removal Equipment and/or Monitoring Connections:	
History of Internal Corrosion:	
Gas Quality Information:	
IMPLEMENTATION OF ADDITIONAL FEATURES TO REDUCE THE RISK OF INTERNAL CORROSION	
Is it impracticable or unnecessary to implement additional design features to reduce the risk of internal corrosion? ☐ Yes ☐ No If yes, document justification.	
Does the configuration of the new or replacement transmission line allow liquids to collect? ☐ Yes ☐ No If yes, consider the installation of Liquid Removal Devices:	
Is there a significant potential for internal corrosion (i.e. liquids are likely to collect and the liquid removal system is not provided or does not effectively remove corrosive liquids)? ☐ Yes ☐ No If yes, provide for the installation of Internal Corrosion Monitoring Devices:	
Does the change in configuration of the transmission line increase the risk for internal corrosion on the downstream transmission line? ☐ Yes ☐ No ☐ N/A If yes, consider the installation of additional Liquid Removal Devices: Internal Corrosion Monitoring Devices:	
Other Comments:	
DESIGN RESPONSIBILITIES	
Engineering:	Title:
Corrosion Front Line Leader/Supervisor:	Title:

Form GS 1420.110-1
(12-31-2012)

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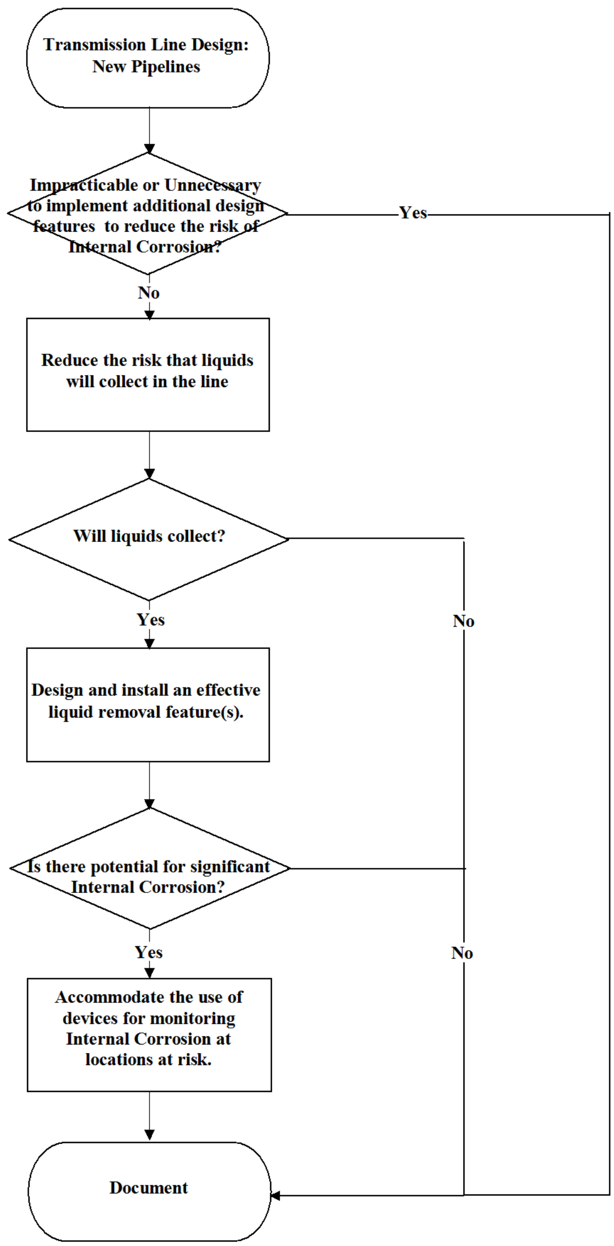
EXHIBIT B



Decision Process for the Design of New Transmission Lines

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Internal Corrosion Design Guidelines for Transmission Lines	Standard Number: **GS 1420.110**
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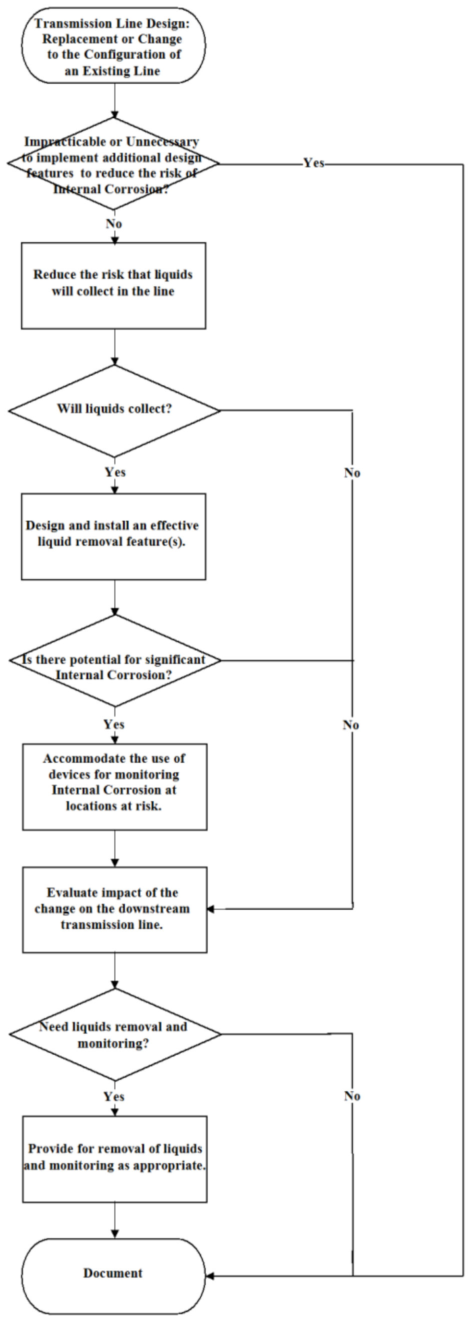
EXHIBIT C



Decision Process for the Design of Replacement Transmission Lines

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Controlling AC Interference**	Standard Number: **GS 1420.120**
Supersedes: 12/31/2012		Page 1 of 13

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.473, 192.491

1. GENERAL

In an Alternating Current (AC) power system, a fault is any abnormal flow of electric current. AC interference or fault currents may come from a nearby electrical source, such as high voltage electric power lines (electric transmission lines or towers), or a lightning strike.

Electrical faults can follow unintended paths back to the source, affecting cathodically protected structures, or personnel, that may come in contact with the path of the electric current. An isolated pipeline or structure (e.g., metal fence, metal post or pole) can pick up currents flowing in the soil, which is often the case when pipelines follow a high voltage electric power line corridor.

Fault currents are a large magnitude of current that can occur in a brief amount of time (normally in milliseconds). Usually, electrical towers or structures have grounding and protection devices that limit the fault current to a brief amount of time.

Electrical energy from an overhead power line can be transferred to a pipeline by three possible mechanisms.

a. Conductive Coupling (occurs during fault conditions) - The influence of two or more circuits on one another by means of resistive paths (metallic, semi-conductive, or electrolytic) between the circuits. Examples include:

   i. current transfer from an electric transmission tower through the ground to an underground metallic pipeline, or

   ii. accidental contact between a power line and another structure, such as a crane or other construction equipment.

   A concerning effect of fault current includes arcing. During a fault-to-ground on an AC power system, the AC power structures and surrounding earth may develop a high potential with reference to remote earth. Arcing may occur if two conductors are close enough for the current to jump or arc, or if a circuit is disconnected and the conductors are close, an arc can occur.

b. Capacitive Coupling (i.e., electrostatic) - The influence of two or more circuits upon one another, through a dielectric medium such as air, by means of the electric field acting between them. An example is an electric field that surrounds electric transmission power cables transfers through a nearby aboveground metallic pipeline (or structure) and the earth, whether that aboveground pipeline is grounded or simply suspended in the air.

c. Inductive Coupling (i.e., electromagnetic) - The influence of two or more circuits upon one another by means of changing magnetic flux linking them together. Potential peaks of current transfer tend to occur at locations in which there are abrupt changes in the arrangement of the facilities or in separation distance. An example is a location where an underground metallic pipeline crosses or deviates from an electric transmission line substation or phase transposition tower. Typically, fault currents peak at the entry of a pipeline into an AC corridor and at the point of exit.

In addition, lightning is a type of fault current. Lightning is an electric discharge that occurs in the atmosphere between clouds or between clouds and the earth during an electrical storm. Other weather conditions can also contribute to fault conditions, such as high winds, ice storms, etc.

AC mitigation is taking the necessary actions to prevent electrical shock or damage to pipelines due to AC interference (or fault current).

2. GENERAL SAFETY CONSIDERATIONS

AC interference can cause hazardous electrical shock by physical contact or even when standing in the vicinity of an energized structure. Potential differences can exist between the energized structure and the ground creating a voltage gradient in the vicinity, which could result in a shock hazard.

An AC voltage of 15 V (i.e., 15 VAC) on a metallic pipeline (or other structure) is considered an electrical shock hazard. This is based on a typical individual, which has approximately 1000 ohms body resistance, and that a typical individual can tolerate 15 mA current. See Table 1 below of possible effects from electrical shocks to a typical human.

Table 1

Effects of Electrical Shocks to a Typical Human (1000 Ohms Body Resistance)		
Voltage	**Current**	**Possible Effect**
>15 V	>15 mA	Muscle contractions; person cannot let go of the object conducting the electrical current.
>50 V	>50 mA	May cause ventricular fibrillation, which may result in death unless treated with emergency medical attention.
>100 V	>100 mA	Ventricular fibrillation is certain, which may result in death unless treated with emergency medical attention.

When working near high voltage electric power lines (i.e., where fault currents are expected to occur), it is recommended that personnel use rubber mats to insulate themselves from the ground, rubber gloves, and high dielectric boots for added insulation to protect themselves from possible electric shock.

In addition, rubber tired vehicles should be kept out of close proximity of high voltage electrical lines, unless equipped with approved grounding devices, such as a heavy grade metallic chain (e.g., logger chain), or properly grounded with a temporary grounding rod.

NOTE: “Static straps” are not approved for use to ground vehicles.

Construction equipment and/or stored pipe may require additional grounding rods. Also, pipe being strung and welded along the route must also be properly grounded and bonded to protect against high-voltage electric shock.

See Section 5.2.1 below for grounding rod details.

Refuel away from the influence area to prevent accidental ignition. If any refueling tanks are in the area, they shall be properly bonded and monitored.

With respect to electrical storms, outdoor construction and operation and maintenance activities should be stopped when lightning activity is present.

3. DETERMINING POTENTIAL AC INTERFERENCE LOCATIONS

Potential AC interference locations include areas where Company pipelines cross or parallel high voltage electric power line corridors. In addition, above ground facilities, such as regulator stations or construction project staging areas, near high voltage electric power line corridors are also potential AC stray current hazards.

An investigation may be warranted when Company or contract personnel experience an electrical shock when working on a Company pipeline, regulator station, meter setting, etc., or if a construction project (plastic or steel) is planned near a high voltage electric power corridor. Contact local corrosion personnel to evaluate and quantify potential hazards, and recommend and oversee the safety measures. Note that some situations may require the Company corrosion personnel to consult with an external contractor for a safety plan specific to the project.

Local corrosion personnel are responsible for mitigating AC interference that impact Company pipelines. Establishing relationships and maintaining communications with local electric company personnel is essential for gathering data required to mitigate AC interference. Local electric company personnel can provide information regarding specific power line data, as well as information about where fault currents have occurred and details regarding magnitude and duration.

While reviewing proposed steel pipeline routes, troubleshooting existing pipelines, investigating Company or contract personnel experiencing an electrical shock when touching a Company facility, etc., corrosion personnel may determine potential AC interference locations that require further investigation and subsequently may require either temporary or permanent AC mitigation measures. The methods for calculating hazards and mitigating AC interference follow in the sections below.

4. CALCULATIONS TO DETERMINE POTENTIAL SHOCK HAZARDS

Once an AC interference issue is identified, calculations can be made to determine if the pipeline or above ground structure require AC mitigation for personal safety reasons.

If the calculated voltages are lower than the possible fault voltage, then additional measures need to be taken to mitigate AC interference.

The following sections provide guidance for calculating potential shock hazards, such as step and touch voltages.

4.1 Step Voltage

Step voltage is the potential difference between two points on the earth's surface separated by a distance of 1 pace (approximately 1 meter) in the direction of the maximum potential gradient. These calculations should be made when Company or contract personnel will be working around high voltage electric power lines and may come within close proximity to electric towers, poles, fence posts, or other above ground metallic structures (including above ground pipelines), Company or contractor construction equipment, pipe stored on racks, etc., which are either temporary or permanent.

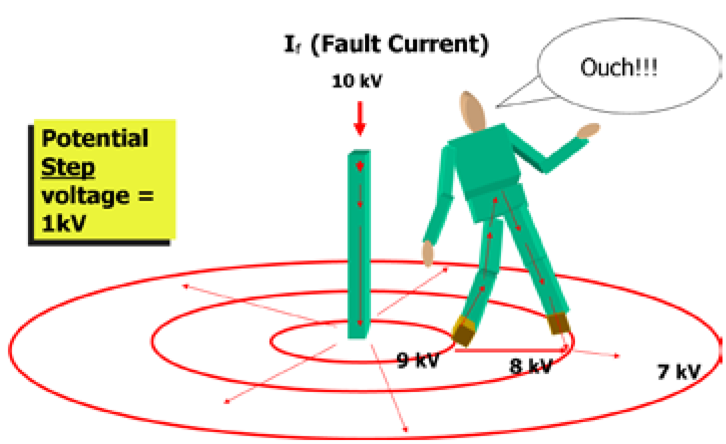


Figure 1: Potential Step Voltage Illustration

The maximum voltage that a typical human body can tolerate by step can be calculated for a 50 kg (or 110 lb) person to be:

$$Vstep = (1000 + 6\rho)\frac{0.116}{\sqrt{t_s}}$$

Where, ρ = soil resistivity (refer to GS 1430.210 "Soil Resistivity Measurements") in ohms-meter

t_s = shock duration, which can be conservatively estimated at 0.5 seconds for fault currents resulting from power lines – verify with electric company.

4.2 Touch Voltage

Touch voltage is the potential difference between the grounded metallic structure and the point of the earth's surface separated by a distance equal to the normal maximum horizontal reach (approximately 1 meter). These calculations should be made when Company personnel will be working on or contacting (i.e., touching) above ground metallic pipelines (e.g., regulator stations, meter settings), Company or contractor construction equipment, pipe stored on racks, etc., which are either temporarily or permanently in the vicinity of high voltage electric power lines.

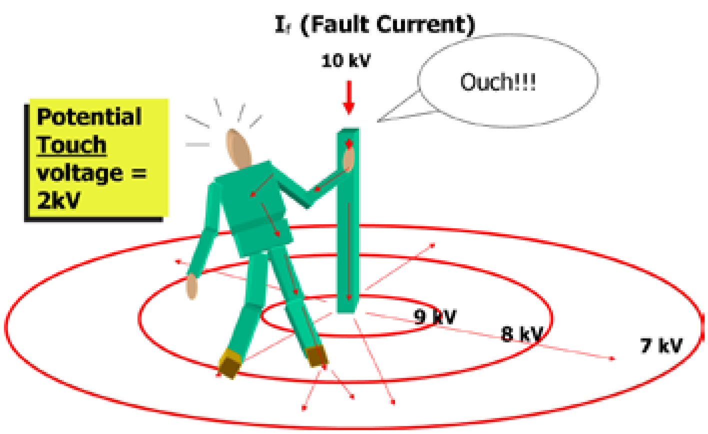


Figure 2: Potential Touch Voltage Illustration

The maximum voltage that a typical human body can tolerate by touch can be calculated for a 50 kg (or 110 lb) person to be:

$$Vtouch = (1000 + 1.5\rho)\frac{0.116}{\sqrt{t_s}}$$

Where, ρ = soil resistivity (refer to GS 1430.210 "Soil Resistivity Measurements") in ohms-meter

t_s = shock duration, which can be conservatively estimated at 0.5 seconds for all fault currents resulting from power lines – verify with electric company.

5. MITIGATION OPTIONS FOR PERSONAL SAFETY

If fault conditions exceed calculated allowable step and touch potentials at any aboveground structures or test stations, AC mitigation measures shall be designed and installed.

5.1 Permanent Mitigation Methods

Permanent mitigation measures are needed in specific areas where contact with the pipeline will be made on a periodic basis (e.g., reading a test station, inspecting a regulator station). Test stations that are installed within areas of AC influence shall be designed according to GS 1420.095 "Corrosion Control Design – Test Stations."

5.1.1 Provide a Permanent Grounding Source

Grounding electrodes, such as zinc ribbon or magnesium anodes, may be evenly distributed along the pipeline by installing packaged sacrificial anodes at regular intervals or by directly burying the zinc ribbon with the pipeline (maintaining proper clearance – refer to Section 6.2.1). However, it is often more effective to concentrate the ground electrodes at electrical discontinuities where the voltage peaks tend to occur. These locations may require complex calculations and shall be the responsibility of corrosion personnel to design. For guidance, contact the local corrosion leader.

Other materials that are not anodic to the pipeline, such as copper cables, can be used for grounding purposes; however, it would seriously impact the effectiveness of the cathodic protection system if directly connected to the pipeline. Therefore, if materials that are not anodic to the pipeline are used for grounding purposes, decouplers shall be included in the AC mitigation design. Refer to Section 6.2.2 for proper installation.

Soil resistivity should be considered in the design to achieve the lowest impedance possible for the best grounding results. The mitigation material's resistance to earth should be at least 2 ohms less that the pipeline characteristic impedance. Ideally, keep the impedance at the lowest value possible, without exceeding 25 ohms.

5.1.2 Increase Surface Layer Resistivity

The surface layer resistivity can be increased by adding 3 to 6 inches of crushed stone or gravel within the perimeter of the area of possible fault current influence or shock hazard by contact to the metallic structure of the pipeline. Design recommendations shall be made by corrosion personnel.

5.1.3 Install a Voltage Gradient Control Mat

A voltage gradient control mat (GCM), preferably made with zinc, is designed to limit the step potential between a workers feet to a safe voltage while standing on the mat and to limit the touch potential to a safe voltage level while standing on the mat and touching any aboveground section of the pipeline. The GCM raises the earth potential closer to that of the pipeline. Below illustrates a typical installation of a voltage gradient mat.

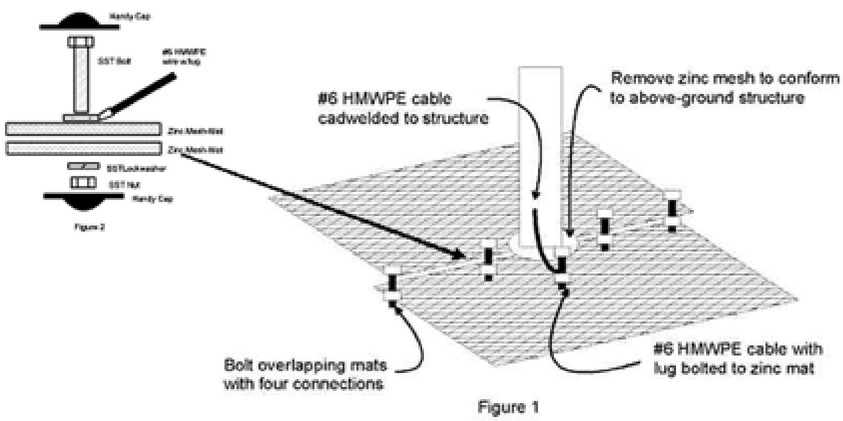


Figure 3: Voltage Gradient Mat Typical Installation

When installing the voltage GCM, layers of the material must be applied for a good soil composite of soil resistivities to prevent a high resistance around the mat that may cause a potential difference between the person and the fault currents. The installation process for a voltage gradient mat in a test station area should be done as follows.

1. Excavate an approximate 4X4 feet hole, at an approximate depth of 30 to 36 inches.
2. Apply a 12” layer of low resistance material, such as coke breeze, benonite or the native soil.
3. Install the zinc gradient control matting.
    i. Normally matting comes in 4 ft. x 8 ft. sheets. Cut the sheets in half to form 4 ft. x 4 ft. sheets.
    ii. Cut a 6” diameter hole in the center of the mat for access to the test station.

iii. Attach two #4 AWG stranded wire on opposite corners with split bolts, make the electrical connection in the junction box with the pipeline.

4. Once all connections have been made, cover the matting with an approximate 12-inch layer of low resistance material.

5. Top off with a layer of high resistance gravel or crushed stone, approximately 6 to 12 inches thick, to meet the existing grade.

5.2 Temporary Mitigation Methods

Temporary mitigation measures can be made when construction or maintenance activities are a one-time expectation, as in the construction of a facility near a high voltage electric power line corridor. Corrosion personnel can take voltage readings, soil resistivity readings, etc. to help develop recommendations for personal safety. Below are some considerations.

a. Make sure vehicles, equipment, pipe storage racks, pipe strung-out for welding, etc. are properly grounded. Heavy grade metallic chains dragging from the vehicle's bumper (e.g., logger chain) in High AC voltage corridors are commonly used to ground moving vehicles. Temporary grounding rods are also used to ground vehicles and equipment, pipe, etc. See Section 5.2.1 below for grounding rod specifications.

   NOTE: "Static straps" are not approved for use to ground vehicles.

b. Determine clearances for potential arcing. Consider boring verses open trench construction, if clearances are difficult to maintain.

c. Recommend appropriate personal protective equipment (PPE) for people at the site.

d. Measure AC potentials on conductors to verify that mitigation process is effective.

5.2.1 Grounding Rod Specifications

Structures, including vehicles, equipment, pipe, etc., can be temporarily grounded by the installation of copper grounding rods. The minimum size for a copper grounding rod is ½-inch diameter. The minimum length is 3 feet, but a typical grounding rod can be 10 feet in length. A minimum #2 AWG stranded cable shall be connected between the structure and the grounded rods. If installing grounding rods within a high resistance soil, multiple rods may need to be installed and should be spaced approximately 6 feet apart.

6. AC INTERFERENCE EFFECT ON PIPELINE PROTECTION

AC interference may cause AC corrosion of the pipeline and/or arcing between the AC structure and the pipeline. Arcing may result in melting or puncturing of the pipe wall, or possibly, embrittlement of the steel in the heat-affected zone which may subsequently lead to hydrogen-induced cracking with the continued application of cathodic protection current.

6.1 AC Corrosion

With AC interference, a concern is that although the pipe-to-soil potential readings may be adequate, there have been studies completed that indicate that corrosion may still take place at certain AC current densities. See Table 2 below.

Table 2

Corrosive Effects of AC Current Density on Steel Pipelines	
AC Current Density	**Corrosive Effect on Steel Pipeline**
< 20 A / m^2	Corrosion will not occur.
20 – 100 A / m^2	Corrosion is unpredictable.
> 100 A / m^2	Corrosion will occur.

The formula to determine AC current density follows below.

$$Iac = \frac{8 \times Vac}{\rho \times \pi \times d}$$

Where, *Iac* = AC current density, in A / m^2

ρ = soil resistivity, in ohm-meters

d = holiday diameter, in meters

6.2 Arcing

The potential for arcing can be determined by calculating the minimum safe distance (R) to maintain between the pipeline and an energized structure. The minimum safe distance (R) can be calculated based on the soil resistivity.

6.2.1 Soil Resistivity Less Than 1000 Ohms-Meter

$$R = 0.08\sqrt{\rho * I_f}$$

Where, R = distance measured in meters,

ρ = soil resistivity (refer to GS 1430.210 "Soil Resistivity Measurements") in ohms-meter,

I_f = magnitude of fault current in kA.

6.2.2 Soil Resistivity Equal To or Greater Than 1000 Ohms-Meter

$$R = 0.047\sqrt{\rho * I_f}$$

Where, R = distance measured in meters,

ρ = soil resistivity (refer to GS 1430.210 "Soil Resistivity Measurements") in ohms-meter,

I_f = magnitude of fault current in kA.

7. AC MITIGATION REQUIREMENTS FOR PIPELINE PROTECTION

Two options to mitigate AC fault currents so that they do not impact the pipeline include maintaining a safe distance between the electric power lines/structures and the pipeline or intercepting the fault currents before they impact the pipeline.

For mitigation of possible corrosion, also refer to Section 5.1.1. By providing a permanent grounding source to mitigate AC current for personal safety, AC currents can be reduced to safe margins that consequently reduce the potential for corrosion.

7.1 Maintain Safe Distance

The preferred method to mitigate arcing concerns on the pipeline is to maintain a safe distance between power line structures and the pipeline. The minimum safe distance (R) can be calculated based on the soil resistivity. Refer to the formulas in Section 6.2 above.

7.2 Intercept Conductive Fault Currents

If the minimum safe distance cannot be maintained, then the fault currents must be intercepted before they reach the pipeline. Screening electrodes may be installed between the pipeline and the electric power lines/towers (e.g., zinc ribbon) or the current can be intercepted and directed back to the power line structure with a copper wire with the use of either a polarized cell replacement (PCR) or insulated surge protector (ISP). With either method, a high dielectric strength coating application shall be selected.

7.2.1 Zinc Ribbon

The installation of zinc ribbon to intercept an AC fault current should adhere to the following guidelines.

a. Place the zinc ribbon below the pipeline.

b. Depending on soil resistivity, the zinc ribbon may need to be installed at a greater depth. It should be in the lowest resistivity area practicable.

c. The zinc ribbon shall be installed a minimum of two (2) feet away from the pipeline.

d. The connection of the zinc ribbon to the pipeline shall be made in a junction box or test station. Refer to GS 1420.095 "Corrosion Control Design – Test Stations."

e. A minimum of a No. 4 gauge wire is used to connect the pipeline and zinc ribbon (evaluate information from the electric company regarding fault currents for proper wire size design).

f. Place the zinc ribbon between the pipeline and AC tower or structure.

g. Splice zinc ribbon by stripping the zinc off the wire (use a small torch) and crimp the connections together or use a copper split bolt. See Figure 4 below.

h. Make crimp repair using an approved method (e.g., epoxy resin kits, insulating/sealing connector, rubber/plastic tape). The thickness and/or electrical insulation properties of the method must be suitable for the possible voltage levels.

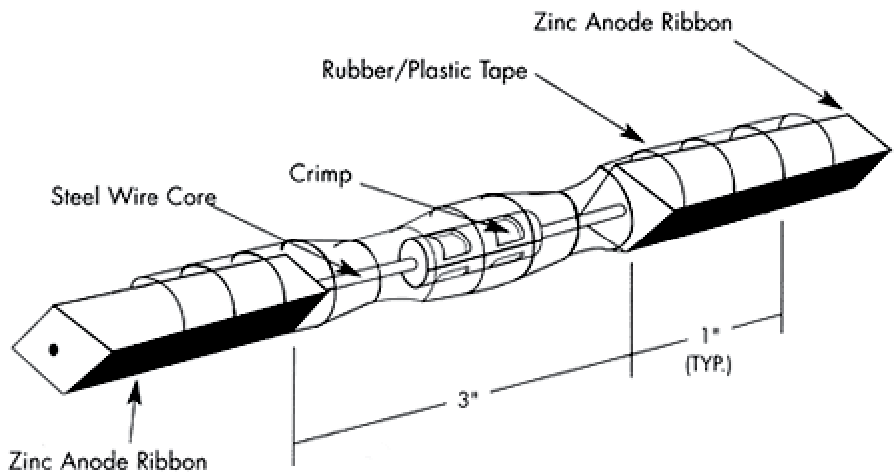


Figure 4: Typical Anode Ribbon Splice Connection

7.2.2 Copper Wire with PCR or ISP

The PCR or ISP can ground the pipeline or structure without shorting out the DC cathodic protection currents. It will block the DC and allow the AC currents flow back to the foreign structure grounding system or pre-made Company grounding systems, such as large AWG copper wiring. Follow manufacturer instructions for the installation of a PCR or ISP.

8. PROTECTION OF INSULATORS

Within AC interference areas, a voltage potential difference may also appear across pipeline electrical isolation devices, possibly causing a failure of the insulator if the voltage exceeds the insulating material's dielectric strength.

Insulators may be protected within AC interference areas by:

a. connecting buried sacrificial anodes to the pipe near the insulating joints,

b. bridging the pipeline insulator with a spark-gap, or

c. other effective means.

9. RECORDS

Existing Company forms shall be used to document test station wiring and location information for AC mitigation test stations. In addition, applicable test station information shall be recorded in the Company's work management system, or equivalent, and maintained for the life of the test station. Test station locations should also be recorded on

Company inventory maps/GIS.

Calculations and recommendations should be filed in the local corrosion records for future reference.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Corrosion Control – Inspection of Steel Pipe Coating	Standard Number: **GS 1420.410**
Supersedes: 12/31/2012		Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.481

1. GENERAL

Steel pipe coating shall be visually inspected prior to acceptance of the pipe from delivery and/or the coating mill. Pipe should be rejected if the coating condition is determined to be unacceptable.

Steel pipe coating shall also be visually or electrically inspected prior to lowering pipe into a ditch to identify damaged coating.

Electrical inspections using a suitable **holiday** detector shall be performed, if required by local corrosion personnel for planned capital design projects and documented on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation (refer to GS 1420.010 “Corrosion Control Design – General”), prior to lowering the pipe into a ditch. Damaged coating shall be repaired according to GS 1420.035 “Coating Repair Methods for Mill Applied Coatings.”

NOTE: Coated steel main or transmission line affected by any field bend shall be electrically inspected with a holiday detector. See Section 8 below.

For the purpose of this gas standard, “planned capital design projects” are those projects that Engineering has developed capital work order(s) to install and/or retire pipeline facilities for new business, leakage replacement, betterment, or relocation purposes. “Planned” may exclude similar work completed under emergency circumstances.

2. INSPECTION AT THE COATING MILL

The request for an inspection at the coating mill shall be made at the discretion of corrosion personnel for steel pipe material orders (e.g., transmission line projects, large orders, bore projects, construction through excessive rock). The request shall be documented by local corrosion personnel on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements.”

A qualified Company corrosion representative or a third party qualified coating inspector contracted by the Company shall perform the inspection of the steel pipe coating at the coating mill to ensure proper coating methods and specifications are met.

Refer to GS 1420.420 "Inspection at the Coating Mill – Fusion Bonded Epoxy (FBE)," GS 1420.430 "Inspection at the Coating Mill – Powercrete," and GS 1420.440 "Inspection at the Coating Mill – Extruded Polyethylene" for inspection standards and specifications.

If the steel pipe material order is filled by current stock and is not sent to a coating mill, a Company representative shall visually inspect the steel pipe coating condition. Corrosion personnel shall be notified by Engineering when the steel pipe order is being filled from stock, with the exception of steel pipe used only for tie-ins.

3. VISUAL INSPECTION PRIOR TO CONSTRUCTION

A visual inspection of steel pipe coating shall be conducted on all steel pipe installations. A visual inspection at the Company storage location, if possible, should be completed by the Company representative in charge of construction of the project prior to scheduling steel pipe for delivery to a job site, to ensure that the coating appears to be in good condition. A visual inspection should also be performed after delivery to the job site by the Company representative in charge of construction of the project, to ensure that the coating was not damaged during transit.

A visual inspection shall include the following items.

a. Check for obvious coating deterioration due to ultraviolet (UV) light exposure.

b. Verify proper coating specifications of what was ordered vs. what was delivered (e.g., print line on coating).

c. Check for obvious coating disbondment.

d. Check for obvious holidays in coating.

Corrosion personnel shall be consulted if the Company representative in charge of construction needs assistance with determining the acceptability of the coating condition.

If a coating mill inspection was requested by corrosion personnel but unable to be completed, a suggested best practice is to take measurements at the job site. The measurements should be three thickness measurements (both ends and the middle) of the coating along 10% of the joints of pipe to be used for the construction project and compare them to the acceptable thickness range of the specified coating (refer to GS 1420.420 "Inspection at the Coating Mill – Fusion Bonded Epoxy (FBE)," GS 1420.430 "Inspection at the Coating Mill – Powercrete," or "GS 1420.440 "Inspection at the Coating Mill – Extruded Polyethylene" for the acceptable total dry film thickness range). If the coating thickness falls outside of the acceptable range, consult with a corrosion front line leader/supervisor for guidance.

4. VISUAL INSPECTION DURING CONSTRUCTION

A visual inspection shall be conducted during construction to observe proper pipe handling methods (refer to GS 3000.010(CG) "Pipe On-Site Handling, Stringing, and Storage" and/or GS 3000.020 "Inspection of Materials"), field installation methods for the coating of bare steel fittings (refer to GS 1420.040 "Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances"), and coating repairs (refer to GS 1420.035 "Coating Repair Methods for Mill Applied Coatings").

5. ELECTRICAL INSPECTION

The electrical holiday detector is a device for locating defects in the pipe coating. Electrical inspection will detect blister type voids, cracks, thin spots and holidays. It does not provide information concerning the coating resistance, bond, physical characteristics or overall quality of the coating.

A final coating inspection, before the coated pipe is placed in the ditch, will disclose any defect or damage to the coating except disbondment, which may have occurred during construction, and usually can be detected by visual inspection. Electrical inspection of pipe coatings prior to installation is an important factor in an effective corrosion control program.

The requirement for electrical inspections of coating shall be documented by local corrosion personnel on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements."

5.1 Holiday Detection Equipment

A direct current (DC) holiday detector is used to apply high voltage to the surface of coatings.

A voltage from 1,000 to 35,000 volts is applied to the coating surface with an exploring electrode consisting of a wire brush, electrically conductive silicone or coil spring. If a holiday or very thin section of coating is passed over by the electrode, a spark will jump from the electrode through the air to the metal. An audio or visual indicator is used to signal a defect.

5.2 Exploring Electrodes

The electrode is the means by which the electrical potential is applied to the surface of the coating. The electrode must maintain contact with the coated surface at all times. The exploring electrode shall be kept clean and free of coating material and rough surfaces that might damage the coating.

5.3 Grounding

Grounding both the pipe metal and the ground terminal of the holiday detector is necessary to complete the circuit. This may be done through a direct wire connection or by using the earth as a common ground. When the pipe is in contact with earth, the holiday detector can, in most cases, be effectively grounded by using a flexible bare wire approximately 30 feet in length connected to the detector ground terminal and trailed along the earth surface. In soils of very high resistance, a direct wire connection between the pipe and detector ground terminal must be maintained.

5.4 Voltage Settings for a DC Holiday Detector

If a non-perforated outer wrap is applied over the primary coating, the thickness and dielectric strength of the outer wrap material must be considered when determining or specifying the test voltage. Certain outer wrap materials may have electrical insulating properties equal to or greater than the coating.

The voltage setting may need to be adjusted for coating repairs and girth weld coatings. Consult manufacturers' specifications for recommended voltage settings for coating repair and girth weld coating applications.

Where the pipeline to be inspected contains coatings of significantly disparate thickness and materials, and it is not feasible to ensure that when testing the thicker (or higher dielectric strength) of the disparate coatings the exploring electrode would not come into contact with the thinner (or lesser dielectric strength) of the disparate coatings, the settings for the thinner (or lesser dielectric strength) of the disparate coatings shall be used to test in those areas.

Table 1 below shows the recommended voltage settings for various thicknesses for different types of mill-applied coatings.

Table 1

Recommended Voltage Setting for a DC Holiday Detector for Mill Applied Coatings

Type of Coating	Thickness (T)	Recommended Voltage Setting[1] (V)	Formula used to determine Recommended Voltage Setting	
Extruded Polyethylene (PE)[2]	10 mils	4000	$Voltage = (1250)\sqrt{T}$	
	20 mils	5600		
	30 mils	6850		
	40 mils	7950		
	50 mils	8850		
	60 mils	9700		
	70 mils	10500		
	80 mils	11200		
Powercrete[3]	21 - 40 mils	3000	N/A	
	41 – 55 mils	4000		
	56 – 80 mils	6000		
	81 - 125 mils	10000		
3M Scotchkote™ FBE[4]	10 mils	1250	$Voltage = 125T$	
	20 mils	2500		
	30 mils	3750		
	40 mils	5000		
	50 mils	6250		

[1] Use the recommended voltage setting for the applicable coating. If the need arises to set the voltage higher than the recommended voltage setting, consult with local corrosion personnel.

[2] Based on guidance provided in NACE SP0185.

[3] For other epoxy based polymer concrete coatings, refer to manufacturer's recommendations.

[4] For other fusion bonded epoxy (FBE) coatings, refer to manufacturer's recommendations.

5.5 Field Use of Equipment

Proper operation of the holiday detector shall be checked at the start of the inspection by making a small pinhole holiday (1/32" diameter is recommended) in the coating, ensuring the pinhole extends completely through the coating to the metal substrate, and passing the electrode over the holiday at a normal traveling speed. If the holiday detector doesn't work at the recommended voltage setting indicated in Table 1 above, quality assurance checks of the holiday detector, ground connections, and/or the pipe coating's dry film thickness (DFT) should be completed. Adjustments to the voltage setting may be necessary to a level sufficient to detect the holiday. If adjustments are greater than +/- 30% of the recommended voltage setting for the actual measured DFT of the coating (per Table 1 above), the holiday detector shall be returned to the manufacturer or authorized agent of the manufacturer for calibration and/or repair.

A best practice is to recheck the holiday detector setting by making a small pinhole holiday (1/32" diameter is recommended) on 10% of the joints of pipe used for the construction project. Sufficient voltage must be applied to allow a spark to jump from the moving electrode across the void in the coating to the pipe.

The electrode should always be in motion whenever the testing voltage is applied.

The electrode should not adversely distort the coating and should not be moved back and forth excessively on a soft coating.

Excessive moisture or any electrically conductive material in or on the surface of the coating system can cause appreciable leakage currents which may lower the effective test voltage or cause erroneous holiday indication. Drying or cleaning of the coating may be necessary.

NOTE: The maximum temperature that Fusion Bonded Epoxy (FBE) coating shall be electrically inspected is 195°F.

5.6 Care of Equipment

All parts of the holiday detector shall be kept clean and free of moisture at all times.

The electrode shall be kept clean and free of coating material and rough surfaces that might damage the coating. The electrode shall be kept in such mechanical condition to maintain contact with the coated surface at all times.

The trailing ground wire shall be kept free of coating material and in such condition to maintain contact with the earth. The ground wire shall be of sufficient length to assure proper grounding.

Test equipment batteries shall be maintained in accordance with the holiday detector manufacturer's recommendations.

6. REPAIR OF COATING

Refer to GS 1420.035 “Coating Repair Methods for Mill Applied Coatings” and/or manufacturer’s specifications.

7. GIRTH WELDS

Girth weld coatings shall be inspected to ensure the coating is the same mil thickness or greater and of compatible material as the pipe coating. Refer to GS 1420.040 “Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances.”

8. FIELD BENDS

Coated steel main or transmission line affected by any field bend shall be electrically inspected with a holiday detector. Coated steel service lines may be visually inspected for coating damage. Particular attention should be made to areas that have been field bent, and necessary repairs to the pipe coating shall be completed.

9. BORES

The coated steel pipe that emerges from a bore shall be visually inspected for coating damage. Typically, additional bore pipe (approximately 10’-20’ extra) is planned for construction. If coating damage has occurred, continue inspecting the coated steel pipe until no damage is found. In the case of dual coated bores where significant damage has occurred to the coating, pipe removal may not be necessary provided that corrosion personnel have been consulted for further evaluation.

10. RECORDS

Completed Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation shall be filed with the applicable work order completion records.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Inspection at the Coating Mill - FBE	Standard Number: GS 1420.420
Supersedes: 03/26/2014		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE The Society for Protective Coatings (SSPC) Surface Preparation (SP) Standard 10, 15

1. GENERAL

This document provides the expectations for inspection of steel pipe coating at the coating mill by a qualified Company corrosion representative or a qualified third party coating inspector contracted by the Company.

2. INSPECTION CRITERIA (HOLD POINTS)

Form GS 1420.410-1 “Inspection at the Coating Mill” (see Exhibit A), or equivalent third party coating inspection company form and/or report, shall be used to document the coating inspection. Use multiple forms as needed for each inspection.

If any of the following inspection criteria do not pass the inspection, the coating process shall be stopped until the test passes inspection.

Tools and equipment used for the following tests shall be calibrated according to manufacturers’ specifications. Calibration procedures and documentation shall be made accessible to the Company.

2.1 Test for Chlorides

This test shall be completed on bare steel pipe before grit blasting prior to the coating process. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

b. The surface is sampled using a Bresle Patch and BresleSampler kit, or equivalent testing kit approved by the local corrosion leader.

c. Document the results of the test in parts per million (ppm) of chloride concentration.

d. Use the guidance provided in the test kit, convert ppm of chloride concentration to micrograms/cm^2 chloride. A maximum of 7 micrograms/cm^2 chloride is acceptable.

2.2 Visual Inspection and Surface Preparation Specifications of Bare Steel Pipe

The visual inspection shall occur before and after the wash and grit blasting processes, but prior to the coating process. The bare steel pipe shall be free from dents or other physical damage (e.g., scratch, gouge, slag that could cause a holiday). If the bare steel pipe contains any defects, it shall be rejected. In addition, the bare steel pipe shall be visually inspected for any grease or contaminants. If grease or contaminants are found prior to grit blasting, then a Methyl Ethyl Ketone (MEK) type solvent shall be used. If grease or contaminants are found after grit blasting, then the process shall stop until corrections/repairs are completed.

The pipe surface shall be grit blasted to a NACE 2/SSPC-SP10 “Near-White Metal Blast Cleaning” specification. The pipe shall be pre-heated to a temperature of no greater than 500°F to remove all moisture after grit blasting.

After the wash and grit blasting processes are completed, the surface area of the pipe shall be 95% uniformed gray with a minimum of 5% of light shadow, very light streaking, or very light discoloration.

2.3 Measure Ambient Conditions and Surface Temperature

Ambient conditions are the prevailing conditions of air temperature, the moisture content of the air (expressed as relative humidity), and the temperature at which condensation will occur (expressed as the dew point temperature). This test shall be completed after the pipe is grit blasted and throughout the coating process.

The following are guidelines for performing this test:

a. Use a psychrometer to measure ambient conditions, in conjunction with the U.S. Weather Bureau Psychrometric Tables.

b. The surface temperature shall remain warmer than the dew point temperature by at least 5°F (3°C).

c. The surface temperature shall be within 425°F to 488°F for the coating application.

d. Measurements shall be taken every two hours, and shall be increased to every hour if conditions appear to be degrading. A best practice is to take measurements during the workforce breaks. If a poor weather condition has halted the work, a new set of data points may be generated every 20-30 minutes, in order to begin or resume final surface preparation and/or painting works as soon as the conditions improve.

e. Documentation of the following information shall be made for each measurement:

1. date,
2. time,
3. dry bulb temperature,
4. wet bulb temperature,
5. relative humidity,
6. dew point temperature,
7. surface temperature, and
8. measurement location (e.g., proximity to spray booth).

2.4 Holiday Detection of the Coated Pipe

This test shall be performed after the coating process is completed. Each coated joint of pipe shall be inspected with a DC **holiday** detector. Refer to GS 1420.410 “Corrosion Control – Inspection of Steel Pipe Coating” for the proper voltage settings for the holiday detector.

NOTE: Inspection is best performed when the temperature of the coating is lower than 194°F.

The coated surface shall be 100% visually inspected to ensure it is free of blisters, bubbles, sags, voids, and other irregularities. All defect areas shall be repaired according to the specifications below.

All coated pipe joints that do not meet the repair or acceptability specifications listed below shall be completely stripped, re-sandblasted, and re-coated.

2.4.1 Repair Specifications

If holidays are found, repairs shall be made according to the specifications indicated below.

a. The area with the holiday(s) shall be cleaned to a SSPC – SP 15, “Commercial Grade Power Tool Cleaning” specification.

b. The holiday repair area shall be coated with epoxy sticks or liquid epoxy.

c. Repair coating shall not be applied to the pipe surface less than 50° F, which may require preheating the holiday area.

d. The repaired coating shall meet the design dry film thickness (DFT) of the pipe coating.

e. The repaired coating shall overlap the existing coating by ¾".

f. The repaired coating shall be re-tested with the DC holiday detector.

2.4.2 Acceptability of Repaired Coated Pipe

The following are the specifications regarding acceptable amounts of repairs to the mill-applied coating.

a. Only 5% or less of total joints with repairs is acceptable.

b. Each repaired joint can have a maximum of two repairs.

c. Repairs requiring stripping of more than 8 square inches of the existing coating shall not be accepted.

2.5 Test for Total Dry Film Thickness (DFT)

This test shall be performed after the coating process is completed with an approved digital instrument. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated. The tests shall be performed at the 6 o'clock and 12 o'clock positions.

b. Dual Coat Process: The preferred thickness range for a dual coat process is 32 to 38 mils, and should be less than 45 mils.

   If the measured thickness for a dual coat process exceeds 45 mils, consult with local corrosion leadership for guidance.

   NOTE: A dual coat thickness over 45 mils may result in coating failure if subjected to bending stresses.

   Single Coat Process: The preferred thickness range for a single coat process is 12 to 18 mils.

c. Documentation of the following information shall be made for each set of measurements:

   1. date,
   2. location along the axis of the pipe and position (e.g., 6 o'clock, 12 o'clock) on pipe,
   3. mil thickness measurement, and
   4. pass or fail, along with the reason of failure and corrective action taken.

2.6 Test for Profile Specifications

This test shall be completed on the bare steel pipe ends (cut back area) after the coating process is completed. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

b. An approved surface profile gauge shall be used to take measurements.

c. The Replica Tape "X-Coarse" shall be used as a comparison for the proper profile pattern required.

d. The profile shall be between 2 mils and 4 mils.

All pipe joints that do not meet the profile specifications shall be completely stripped, re-sandblasted, and re-coated.

3. HARDNESS TESTING

The coated pipe shall not be transported until it reaches D shore hardness of 85. This can be also measured by doing a "thumb nail" test. If the thumb nail leaves an imprint in the FBE coating, then it has not reached a D shore hardness of 85.

4. DESTRUCTIVE TESTING

Local corrosion leadership may make a recommendation for destructive testing based on certain circumstances, such as material orders for transmission lines or large projects. The specifications of the destructive tests shall be designated by local corrosion personnel, referencing the appropriate American Society for Testing and Materials (ASTM) standards and methodology for tests, such as the 28-day cathodic disbondment test, back film contamination test, and adhesion test.

If destructive testing is recommended, then local corrosion personnel should also recommend ordering additional coated pipe.

These recommendations should be documented on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements."

5. RECORDS

Completed inspection form(s)/report(s) shall be returned to the Company. The Company should file the inspection form(s)/report(s) with applicable work order completion records.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Inspection at the Coating Mill - FBE	Standard Number: GS 1420.420
Supersedes: 03/26/2014		Page 6 of 6

EXHIBIT A

INSPECTION AT THE COATING MILL

Work Order and/or Purchase Order # : ______ Date: ______
Inspector Name: ______ Inspector Company: ______
Coating Mill Name & Location: ______

Coating Application: FBE ☐ Epoxy Based Polymer Concrete ☐ Extruded Polyethylene ☐
Description of Coating Order: ____ feet of ____ inch steel pipe

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: ____ °F Wet Bulb Temperature: ____ °F
Relative Humidity: ____
Dew Point Temperature: ____ °F Surface Temperature: ____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: ____ °F Wet Bulb Temperature: ____ °F
Relative Humidity: ____
Dew Point Temperature: ____ °F Surface Temperature: ____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Surface Inspection for Oils, Solvents, Grease, and/or Dirt (to be completed on FBE coated pipe prior to Epoxy Based Polymer Concrete application):
Date: ______ Time: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Chlorides:
Date: ______ Time: ______
Joint #: ____
Chloride Concentration: ______ ppm
Chloride Concentration: ______ micrograms/cm²
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Chlorides:
Date: ______ Time: ______
Joint #: ____
Chloride Concentration: ______ ppm
Chloride Concentration: ______ micrograms/cm²
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Visual Inspection (to be completed on bare steel pipe before and after grit blasting, but prior to FBE or Extruded Polyethylene coating process):
Date: ______ Time: ______
Free from dents or other physical damage: Yes ☐ No ☐ If no, explain action taken: ______
Free from grease or contaminants: Yes ☐ No ☐ If no, explain corrective action taken: ______

Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):
Date: ______ Time: ______
Joint #: ____
Profile: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):
Date: ______ Time: ______
Joint #: ____
Profile: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Temperature of Butyl Adhesive (Extruded Polyethylene coating process only):
Date: ______ Time: ______ Temperature: ____ °F

Test for Wet Film Thickness (Extruded Polyethylene adhesive only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Wet Film Thickness (Extruded Polyethylene adhesive only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Hardness (Epoxy Based Polymer Concrete only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Hardness (Epoxy Based Polymer Concrete only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Total Dry Film Thickness (DFT):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Total Dry Film Thickness (DFT):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Holiday Detection: Date: ______ # Joints Inspected: ______

Joint 1, # holidays: ____	Joint 16, # holidays: ____	Joint 31, # holidays: ____	Joint 46, # holidays: ____
Joint 2, # holidays: ____	Joint 17, # holidays: ____	Joint 32, # holidays: ____	Joint 47, # holidays: ____
Joint 3, # holidays: ____	Joint 18, # holidays: ____	Joint 33, # holidays: ____	Joint 48, # holidays: ____
Joint 4, # holidays: ____	Joint 19, # holidays: ____	Joint 34, # holidays: ____	Joint 49, # holidays: ____
Joint 5, # holidays: ____	Joint 20, # holidays: ____	Joint 35, # holidays: ____	Joint 50, # holidays: ____
Joint 6, # holidays: ____	Joint 21, # holidays: ____	Joint 36, # holidays: ____	Joint 51, # holidays: ____
Joint 7, # holidays: ____	Joint 22, # holidays: ____	Joint 37, # holidays: ____	Joint 52, # holidays: ____
Joint 8, # holidays: ____	Joint 23, # holidays: ____	Joint 38, # holidays: ____	Joint 53, # holidays: ____
Joint 9, # holidays: ____	Joint 24, # holidays: ____	Joint 39, # holidays: ____	Joint 54, # holidays: ____
Joint 10, # holidays: ____	Joint 25, # holidays: ____	Joint 40, # holidays: ____	Joint 55, # holidays: ____
Joint 11, # holidays: ____	Joint 26, # holidays: ____	Joint 41, # holidays: ____	Joint 56, # holidays: ____
Joint 12, # holidays: ____	Joint 27, # holidays: ____	Joint 42, # holidays: ____	Joint 57, # holidays: ____
Joint 13, # holidays: ____	Joint 28, # holidays: ____	Joint 43, # holidays: ____	Joint 58, # holidays: ____
Joint 14, # holidays: ____	Joint 29, # holidays: ____	Joint 44, # holidays: ____	Joint 59, # holidays: ____
Joint 15, # holidays: ____	Joint 30, # holidays: ____	Joint 45, # holidays: ____	Joint 60, # holidays: ____

Form GS 1420.410-1
(01-2016)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Inspection at the Coating Mill – Epoxy Based Polymer Concrete**	Standard Number: **GS 1420.430**
Supersedes: 03/26/2014		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE The Society for Protective Coatings (SSPC) Surface Preparation (SP) Standard 1, 15

1. GENERAL

This document provides the expectations for inspection of steel pipe coating at the coating mill by a qualified Company corrosion representative or a qualified third party coating inspector contracted by the Company.

2. INSPECTION OF INITIAL LAYER OF FUSION BONDED EPOXY (FBE) COATING

Typically an epoxy based polymer concrete coating is applied over fusion bonded epoxy (FBE) coating. Therefore the initial layer of FBE should be inspected at the coating mill according to GS 1420.420 "Inspection at the Coating Mill – Fusion Bonded Epoxy (FBE)."

If the FBE was not inspected at the coating mill or was transported after its inspection at the coating mill prior to the application of the epoxy based polymer concrete coating, then the FBE coated steel pipe shall be inspected with a DC **holiday** detector prior to the application of the epoxy based polymer concrete coating. Refer to GS 1420.410 "Corrosion Control – Inspection of Steel Pipe Coating" for guidance regarding the holiday detection inspection and the repair of holiday(s) found.

a. If the FBE pipe shows damage on more than 5% of the total pipe footage, then the pipe is rejected and new coated pipe will be supplied.

b. If the FBE pipe already shows previous signs of repairs, and it exceeds two repairs per joint, then the pipe is rejected and new coated pipe will be supplied.

c. If the FBE pipe indicates repaired areas greater than 8 square inches, then the pipe is rejected and new coated pipe will be supplied.

3. INSPECTION CRITERIA (HOLD POINTS)

Form GS 1420.410-1 "Inspection at the Coating Mill" (see Exhibit A), or equivalent third party coating inspection company form and/or report, shall be used to document the coating inspection. Use multiple forms as needed for each inspection.

If any of the following hold points do not pass the inspection, the coating process shall be stopped until the test passes inspection.

Tools and equipment used for the following tests shall be calibrated according to manufacturers' specifications. Calibration procedures and documentation shall be made accessible to the Company.

3.1 Surface Inspection for Oils, Solvents, Grease, and/or Dirt

This inspection shall be completed on the FBE coated pipe, prior to the epoxy based polymer concrete coating process. The following are guidelines for performing this inspection.

a. Test and clean with a white cotton rag for any deposits on the surface of the FBE coated pipe according to SSPC – SP1 "Solvent Cleaning" specifications.

b. If deposits are found, the surface shall be cleaned with a Methyl Ethyl Ketone (MEK) type solvent until the deposits have been removed.

3.2 Test for Chlorides

This test shall be completed on the FBE coated pipe, prior to the epoxy based polymer concrete coating process. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

b. The surface is sampled using a Bresle Patch and BresleSampler kit, or equivalent testing kit approved for use by the local corrosion leader.

c. Document the results of the test in parts per million (ppm) of chloride concentration.

d. Use the guidance provided in the test kit, convert ppm of chloride concentration to micrograms/cm^2 chloride. A maximum of 7 micrograms/cm^2 chloride is acceptable.

3.3 Measure Ambient Conditions and Surface Temperature

Ambient conditions are the prevailing conditions of air temperature, the moisture content of the air (expressed as relative humidity), and the temperature at which condensation will occur (expressed as the dew point temperature). This test shall be completed throughout the coating process.

The following are guidelines for performing this test:

a. Use a psychrometer to measure ambient conditions, in conjunction with the U.S. Weather Bureau Psychrometric Tables.

b. The surface temperature shall remain warmer than the dew point temperature by at least 5°F (3°C).

c. Measurements shall be taken every four hours, and shall be increased to every hour if conditions appear to be degrading. A best practice is to take measurements during the workforce breaks. If a poor weather condition has halted the work, a new set of data points may be generated every 20-30 minutes, in order to begin or resume final surface preparation and/or painting works as soon as the conditions improve.

d. Documentation of the following information shall be made for each measurement:

1. date,
2. time,
3. dry bulb temperature,
4. wet bulb temperature,
5. relative humidity,
6. dew point temperature,
7. surface temperature, and
8. measurement location (e.g., proximity to spray booth).

3.4 Test for Hardness

This test shall be completed after the final application of epoxy based polymer concrete coating. The following are guidelines for performing this test.

a. A type D shore Durometer shall be used to measure the hardness.

b. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

c. A value of at least 75 is acceptable.

3.5 Test for Total Dry Film Thickness (DFT)

This test shall be completed after the final application of epoxy based polymer concrete coating. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated. The tests shall be performed at the 6 o'clock and 12 o'clock positions.

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b. Dual Coat Process: The preferred thickness range for a dual coat epoxy based polymer concrete process with an initial FBE single layer is 52 to 58 mils, not to exceed 125 mils.

Single Coat Process: The preferred thickness range for a single coat epoxy based polymer concrete process with an initial FBE single layer is 32 to 38 mils, not to exceed 125 mils.

c. Documentation of the following information shall be made for each set of measurements:

1. date,
2. location along the axis of the pipe and position (e.g., 6 o'clock, 12 o'clock) on pipe,
3. mil thickness measurement, and
4. pass or fail, along with the reason of failure and corrective action taken.

3.6 Holiday Detection of the Coated Pipe

This test shall be performed after the coating process is completed. Each coated joint of pipe shall be inspected with a DC holiday detector. Refer to GS 1420.410 "Corrosion Control – Inspection of Steel Pipe Coating" for the proper voltage settings for the holiday detector.

If holidays are found, repairs shall be made according to the specifications indicated below.

a. The area with the holiday(s) shall be cleaned to a SSPC – SP 15 "Commercial Grade Power Tool Cleaning" specification.

b. The holiday repair area shall be coated with a compatible product, as specified by the epoxy based polymer concrete coating manufacturer.

c. The repaired coating shall meet the design dry film thickness (DFT) of the pipe coating.

d. The repaired coating shall overlap the existing coating by ¾".

e. The repaired coating shall be re-tested with the DC holiday detector.

4. DESTRUCTIVE TESTING

Local corrosion leadership may make a recommendation for destructive testing based on certain circumstances, such as material orders for transmission lines or large projects. The specifications of the destructive tests shall be designated by local corrosion personnel, referencing the appropriate American Society for Testing and Materials (ASTM) standards and methodology for tests, such as the impact resistance test and/or the adhesion test.

If destructive testing is recommended, then local corrosion personnel should also recommend ordering additional coated pipe.

These recommendations should be documented on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements.”

5. RECORDS

Completed inspection form(s)/report(s) shall be returned to the Company. The Company should file the inspection form(s)/report(s) with the applicable work order completion records.

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EXHIBIT A

INSPECTION AT THE COATING MILL

Work Order and/or Purchase Order # : ______ Date: ______
Inspector Name: ______ Inspector Company: ______
Coating Mill Name & Location:

Coating Application: FBE ☐ Epoxy Based Polymer Concrete ☐ Extruded Polyethylene ☐
Description of Coating Order: _____ feet of _____ inch steel pipe

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: _____ °F Wet Bulb Temperature: _____ °F
Relative Humidity: _____
Dew Point Temperature: _____ °F Surface Temperature: _____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: _____ °F Wet Bulb Temperature: _____ °F
Relative Humidity: _____
Dew Point Temperature: _____ °F Surface Temperature: _____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Surface Inspection for Oils, Solvents, Grease, and/or Dirt (to be completed on FBE coated pipe prior to Epoxy Based Polymer Concrete application):
Date: ______ Time: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Chlorides:	Test for Chlorides:
Date: ______ Time: ______	Date: ______ Time: ______
Joint #: _____	Joint #: _____
Chloride Concentration: ______ ppm	Chloride Concentration: ______ ppm
Chloride Concentration: ______ micrograms/cm²	Chloride Concentration: ______ micrograms/cm²
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______	Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Visual Inspection (to be completed on bare steel pipe before and after grit blasting, but prior to FBE or Extruded Polyethylene coating process):
Date: ______ Time: ______
Free from dents or other physical damage: Yes ☐ No ☐ If no, explain action taken: ______
Free from grease or contaminants: Yes ☐ No ☐ If no, explain corrective action taken: ______

Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):	Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):
Date: ______ Time: ______	Date: ______ Time: ______
Joint #: _____	Joint #: _____
Profile: _____ mils	Profile: _____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______	Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Temperature of Butyl Adhesive (Extruded Polyethylene coating process only):
Date: Time: Temperature: °F

Test for Wet Film Thickness (Extruded Polyethylene adhesive only):	Test for Wet Film Thickness (Extruded Polyethylene adhesive only):
Date: ______ Time: ______	Date: ______ Time: ______
Joint #: _____	Joint #: _____
6 o'clock: _____ mils 12 o'clock: _____ mils	6 o'clock: _____ mils 12 o'clock: _____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______	Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Hardness (Epoxy Based Polymer Concrete only):	Test for Hardness (Epoxy Based Polymer Concrete only):
Date: ______ Time: ______	Date: ______ Time: ______
Joint #: _____	Joint #: _____
6 o'clock: _____ mils 12 o'clock: _____ mils	6 o'clock: _____ mils 12 o'clock: _____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______	Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Total Dry Film Thickness (DFT):	Test for Total Dry Film Thickness (DFT):
Date: ______ Time: ______	Date: ______ Time: ______
Joint #: _____	Joint #: _____
6 o'clock: _____ mils 12 o'clock: _____ mils	6 o'clock: _____ mils 12 o'clock: _____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______	Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Holiday Detection: Date: # Joints Inspected:

Joint 1, # holidays: ____	Joint 16, # holidays: ____	Joint 31, # holidays: ____	Joint 46, # holidays: ____
Joint 2, # holidays: ____	Joint 17, # holidays: ____	Joint 32, # holidays: ____	Joint 47, # holidays: ____
Joint 3, # holidays: ____	Joint 18, # holidays: ____	Joint 33, # holidays: ____	Joint 48, # holidays: ____
Joint 4, # holidays: ____	Joint 19, # holidays: ____	Joint 34, # holidays: ____	Joint 49, # holidays: ____
Joint 5, # holidays: ____	Joint 20, # holidays: ____	Joint 35, # holidays: ____	Joint 50, # holidays: ____
Joint 6, # holidays: ____	Joint 21, # holidays: ____	Joint 36, # holidays: ____	Joint 51, # holidays: ____
Joint 7, # holidays: ____	Joint 22, # holidays: ____	Joint 37, # holidays: ____	Joint 52, # holidays: ____
Joint 8, # holidays: ____	Joint 23, # holidays: ____	Joint 38, # holidays: ____	Joint 53, # holidays: ____
Joint 9, # holidays: ____	Joint 24, # holidays: ____	Joint 39, # holidays: ____	Joint 54, # holidays: ____
Joint 10, # holidays: ____	Joint 25, # holidays: ____	Joint 40, # holidays: ____	Joint 55, # holidays: ____
Joint 11, # holidays: ____	Joint 26, # holidays: ____	Joint 41, # holidays: ____	Joint 56, # holidays: ____
Joint 12, # holidays: ____	Joint 27, # holidays: ____	Joint 42, # holidays: ____	Joint 57, # holidays: ____
Joint 13, # holidays: ____	Joint 28, # holidays: ____	Joint 43, # holidays: ____	Joint 58, # holidays: ____
Joint 14, # holidays: ____	Joint 29, # holidays: ____	Joint 44, # holidays: ____	Joint 59, # holidays: ____
Joint 15, # holidays: ____	Joint 30, # holidays: ____	Joint 45, # holidays: ____	Joint 60, # holidays: ____

Form GS 1420.410-1
(01-2016)

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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE The Society for Protective Coatings (SSPC) Surface Preparation (SP) Standard 10, 15

1. GENERAL

This document provides the expectations for inspection of steel pipe coating at the coating mill by a qualified Company corrosion representative or a qualified third party coating inspector contracted by the Company.

2. INSPECTION CRITERIA (HOLD POINTS)

Form GS 1420.410-1 “Inspection at the Coating Mill” (see Exhibit A), or equivalent third party coating inspection company form and/or report, shall be used to document the coating inspection. Use multiple forms as needed for each inspection.

If any of the following inspection criteria do not pass the inspection, the coating process shall be stopped until the test passes inspection.

Tools and equipment used for the following tests shall be calibrated according to manufacturers’ specifications. Calibration procedures and documentation shall be made accessible to the Company.

2.1 Test for Chlorides

This test shall be completed on bare steel pipe before grit blasting prior to the coating process. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

b. The surface is sampled using a Bresle Patch and BresleSampler kit, or equivalent testing kit approved by the local corrosion leader.

c. Document the results of the test in parts per million (ppm) of chloride concentration.

d. Use the guidance provided in the test kit, convert ppm of chloride concentration to micrograms/cm^2 chloride. A maximum of 7 micrograms/cm^2 chloride is acceptable.

2.2 Visual Inspection and Surface Preparation Specifications of Bare Steel Pipe

The visual inspection shall occur before and after the wash and grit blasting processes, but prior to the coating process. The bare steel pipe shall be free from dents or other physical damage. In addition, the bare steel pipe shall be visually inspected for any grease or contaminants. If grease or contaminants are found prior to grit blasting, then a Methyl Ethyl Ketone (MEK) type solvent shall be used. If grease or contaminants are found after grit blasting, then the process shall stop until corrections/repairs are completed.

The pipe surface shall be grit blasted to a NACE 2/SSPC-SP10 “Near-White Metal Blast Cleaning” specification. The pipe shall be pre-heated to a temperature of no greater than 500°F to remove all moisture after grit blasting.

After the wash and grit blasting processes are completed, the surface area of the pipe shall be 95% uniformed gray with a minimum of 5% of light shadow, very light streaking, or very light discoloration.

2.3 Measure Ambient Conditions and Surface Temperature

Ambient conditions are the prevailing conditions of air temperature, the moisture content of the air (expressed as relative humidity), and the temperature at which condensation will occur (expressed as the dew point temperature). This test shall be completed after the pipe is grit blasted and throughout the coating process.

The following are guidelines for performing this test:

a. Use a psychrometer to measure ambient conditions, in conjunction with the U.S. Weather Bureau Psychrometric Tables.

b. The surface temperature shall remain warmer than the dew point temperature by at least 5°F (3°C).

c. Measurements shall be taken every four hours, and shall be increased to every hour if conditions appear to be degrading. A best practice is to take measurements during the workforce breaks. If a poor weather condition has halted the work, a new set of data points may be generated every 20-30 minutes, in order to begin or resume final surface preparation and/or painting works as soon as the conditions improve.

d. Documentation of the following information shall be made for each measurement:

   1. date,
   2. time,
   3. dry bulb temperature,

4. wet bulb temperature,
5. relative humidity,
6. dew point temperature,
7. surface temperature, and
8. measurement location (e.g., proximity to spray booth).

2.4 Test for Butyl Adhesive Temperature

The temperature for the butyl adhesive material shall be in the range of 280°F and 340 °F. This test is typically performed by the coating mill, and the inspector shall validate the temperature is within the specified range.

2.5 Test for Wet Film Thickness (WFT) of Adhesive

This test shall be completed after the adhesive application is completed. This test is typically performed by the coating mill, and the inspector shall validate the results. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated. The tests shall be performed at the 6 o'clock and 12 o'clock positions.

b. The minimum thickness of adhesive is 8 mils.

c. Documentation of the following information shall be made for each set of measurements:

    1. date,
    2. location along the axis of the pipe and position (e.g., 6 o'clock, 12 o'clock) on pipe,
    3. mil thickness measurement, and
    4. pass or fail, along with the reason of failure and corrective action taken.

2.6 Holiday Detection of the Coated Pipe

This test shall be performed after the coating process is completed. Each coated joint of pipe shall be inspected with a DC **holiday** detector. Refer to GS 1420.410 "Corrosion Control – Inspection of Steel Pipe Coating" for the proper voltage settings for the holiday detector.

All coated pipe joints that do not meet the repair or acceptability specifications listed

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below shall be completely stripped, re-sandblasted, and re-coated.

2.6.1 Repair Specifications

If holidays are found, repairs shall be made according to the specifications indicated below.

a. The area with the holiday(s) shall be cleaned to a SSPC – SP 15, "Commercial Grade Power Tool Cleaning" specification.

b. The holiday repair area shall be coated with butyl cold applied tape, such as Polyken 936, Tapecoat H35, or equivalent, following manufacturer's instructions. Under <u>no circumstances</u> are heat shrink sleeves to be used.

c. The tape must be double applied in order to maintain the same mil thickness of the mill-applied coating.

   1. The repaired coating shall be applied in a cigarette wrap method and overlap the existing coating by a minimum of 2".
   2. The repaired coating shall be re-tested with the DC holiday detector.
   3. Under <u>no circumstances</u> are repairs to be made by applying an extra layer of butyl adhesive with an outer coat of polyethylene.

2.6.2 Acceptability of Repaired Coated Pipe

The following are the specifications regarding acceptable amounts of repairs to the mill-applied coating.

a. Only 5% or less of total joints with repairs is acceptable.

b. Each repaired joint can have a maximum of two repairs.

c. Repairs requiring stripping of more than 8 square inches of the existing coating shall not be accepted.

2.7 Test for Total Dry Film Thickness (DFT)

This test shall be performed after the coating process is completed. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated. The tests shall be performed at the 6 o'clock and 12 o'clock positions.

b. The thickness range for the total coating shall be within 68 to 79 mils for X-tec II specifications or within 44 to 64 mils for Pritec specifications.

c. Documentation of the following information shall be made for each set of measurements:

1. date,
2. location along the axis of the pipe and position (e.g., 6 o'clock, 12 o'clock) on pipe,
3. mil thickness measurement, and
4. pass or fail, along with the reason of failure and corrective action taken.

2.8 Test for Profile Specifications

This test shall be completed on the bare steel pipe ends (cut back area) after the coating process is completed. The following are guidelines for performing this test.

a. The testing sample shall be 10% of the number of joints ordered. The tests should be spread out over the beginning, middle, and end of the process each day. A minimum of one test shall be performed if there are less than 10 joints of pipe being coated.

b. An approved surface profile gauge shall be used to take measurements.

c. The Replica Tape "X-Coarse" shall be used as a comparison for the proper profile pattern required.

d. The profile shall be between 2 mils and 4.5 mils.

All pipe joints that do not meet the profile specifications shall be completely stripped, re-sandblasted, and re-coated.

3. DESTRUCTIVE TESTING

Local corrosion leadership may make a recommendation for destructive testing based on certain circumstances, such as material orders for transmission lines or large projects. The specifications of the destructive tests shall be designated by local corrosion personnel, referencing the appropriate American Society for Testing and Materials (ASTM) standards and methodology for tests, such as the 28-day cathodic disbondment test and the peel test.

If destructive testing is recommended, then local corrosion personnel should also recommend ordering additional coated pipe.

These recommendations should be documented on Form GS 1420.010-1, "Transmittal of Corrosion Control Requirements."

4. RECORDS

Completed inspection form(s)/report(s) shall be returned to the Company. The Company should file the inspection form(s)/report(s) with applicable work order completion records.

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EXHIBIT A

INSPECTION AT THE COATING MILL

Work Order and/or Purchase Order # : ______ Date: ______
Inspector Name: ______ Inspector Company: ______
Coating Mill Name & Location: ______

Coating Application: FBE ☐ Epoxy Based Polymer Concrete ☐ Extruded Polyethylene ☐
Description of Coating Order: ____ feet of ____ inch steel pipe

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: ____ °F Wet Bulb Temperature: ____ °F
Relative Humidity: ____
Dew Point Temperature: ____ °F Surface Temperature: ____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Ambient Conditions at the Coating Mill:
Date: ______ Time: ______
Dry Bulb Temperature: ____ °F Wet Bulb Temperature: ____ °F
Relative Humidity: ____
Dew Point Temperature: ____ °F Surface Temperature: ____ °F
Measurement Location: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Surface Inspection for Oils, Solvents, Grease, and/or Dirt (to be completed on FBE coated pipe prior to Epoxy Based Polymer Concrete application):
Date: ______ Time: ______
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Chlorides:
Date: ______ Time: ______
Joint #: ____
Chloride Concentration: ______ ppm
Chloride Concentration: ______ micrograms/cm²
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Chlorides:
Date: ______ Time: ______
Joint #: ____
Chloride Concentration: ______ ppm
Chloride Concentration: ______ micrograms/cm²
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Visual Inspection (to be completed on bare steel pipe before and after grit blasting, but prior to FBE or Extruded Polyethylene coating process):
Date: ______ Time: ______
Free from dents or other physical damage: Yes ☐ No ☐ If no, explain action taken: ______
Free from grease or contaminants: Yes ☐ No ☐ If no, explain corrective action taken: ______

Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):
Date: ______ Time: ______
Joint #: ____
Profile: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Profile Specifications (n/a for Epoxy Based Polymer Concrete):
Date: ______ Time: ______
Joint #: ____
Profile: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Temperature of Butyl Adhesive (Extruded Polyethylene coating process only):
Date: Time: Temperature: °F

Test for Wet Film Thickness (Extruded Polyethylene adhesive only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Wet Film Thickness (Extruded Polyethylene adhesive only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Hardness (Epoxy Based Polymer Concrete only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Hardness (Epoxy Based Polymer Concrete only):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Total Dry Film Thickness (DFT):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Test for Total Dry Film Thickness (DFT):
Date: ______ Time: ______
Joint #: ____
6 o'clock: ____ mils 12 o'clock: ____ mils
Acceptable: Yes ☐ No ☐ If not acceptable, explain corrective action taken: ______

Holiday Detection: Date: ______ # Joints Inspected: ______

Joint 1, # holidays: ____	Joint 16, # holidays: ____	Joint 31, # holidays: ____	Joint 46, # holidays: ____
Joint 2, # holidays: ____	Joint 17, # holidays: ____	Joint 32, # holidays: ____	Joint 47, # holidays: ____
Joint 3, # holidays: ____	Joint 18, # holidays: ____	Joint 33, # holidays: ____	Joint 48, # holidays: ____
Joint 4, # holidays: ____	Joint 19, # holidays: ____	Joint 34, # holidays: ____	Joint 49, # holidays: ____
Joint 5, # holidays: ____	Joint 20, # holidays: ____	Joint 35, # holidays: ____	Joint 50, # holidays: ____
Joint 6, # holidays: ____	Joint 21, # holidays: ____	Joint 36, # holidays: ____	Joint 51, # holidays: ____
Joint 7, # holidays: ____	Joint 22, # holidays: ____	Joint 37, # holidays: ____	Joint 52, # holidays: ____
Joint 8, # holidays: ____	Joint 23, # holidays: ____	Joint 38, # holidays: ____	Joint 53, # holidays: ____
Joint 9, # holidays: ____	Joint 24, # holidays: ____	Joint 39, # holidays: ____	Joint 54, # holidays: ____
Joint 10, # holidays: ____	Joint 25, # holidays: ____	Joint 40, # holidays: ____	Joint 55, # holidays: ____
Joint 11, # holidays: ____	Joint 26, # holidays: ____	Joint 41, # holidays: ____	Joint 56, # holidays: ____
Joint 12, # holidays: ____	Joint 27, # holidays: ____	Joint 42, # holidays: ____	Joint 57, # holidays: ____
Joint 13, # holidays: ____	Joint 28, # holidays: ____	Joint 43, # holidays: ____	Joint 58, # holidays: ____
Joint 14, # holidays: ____	Joint 29, # holidays: ____	Joint 44, # holidays: ____	Joint 59, # holidays: ____
Joint 15, # holidays: ____	Joint 30, # holidays: ____	Joint 45, # holidays: ____	Joint 60, # holidays: ____

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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Installation of Galvanic Anodes	Standard Number: GS 1420.510
Supersedes: 01/01/2012		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.491

1. GENERAL

This standard provides guidance on the installation of galvanic anodes on new and existing pipelines for new/replacement projects and maintenance work.

For new/replacement capital designed projects, the type, number, and spacing of anodes, as well as the type of installation (i.e., single vs. multiple along a gathering wire) shall be installed as indicated on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" and/or as indicated on the work order drawings or engineering plans.

For maintenance work, anodes shall be installed as directed by GS 1460.010 "Corrosion Remedial Measures - Distribution."

Wire connections to a metallic pipeline should be attached by the thermite weld process. Mechanical connections may be used only where the thermite process is unsafe. Refer to GS 1420.580 "Thermite Weld Process" for additional guidance.

2. INSTALLATION BY ANODE TYPE

2.1 Zinc Anodes

The 1 pound zinc anode, or equivalent, may be installed on isolated metallic fittings or valves installed in plastic piping systems.

The anode should be placed approximately one foot away from the fitting and its wire connected either by thermite weld or crimp connector to the fitting body. Clean and coat the thermite connection according to GS 1420.580 "Thermite Weld Process."

2.2 Magnesium Anodes

The 3-, 9-, and 17-pound high potential magnesium anodes are the standard sizes. Other sizes may be installed where required by a particular design. Common applications include:

a. the 3-pound anode for work associated with isolated service lines or risers;

b. the 9-pound anode for installations on bare pipelines during maintenance work such as leak repairs and other exposures; and

c. the 17-pound anode for steel pipe installations, mitigation programs, and remediation of cathodic protection on existing coated pipelines.

Magnesium anodes are purchased in pre-packaged units consisting of a single anode and backfill material contained in a cloth bag and shipping package. The shipping package shall be removed from the anode prior to installation.

The anode should be placed at a depth greater than the depth of the pipe bottom to ensure the anode is in soil that generally remains moist year around. It is recommended that the separation between the anode and the pipe be at least five (5) feet for bare steel and three (3) feet for coated steel, but be a minimum of two (2) feet, where practicable. See Figure 1 below. The anode or package contents shall not be in contact with the pipe or other structures.

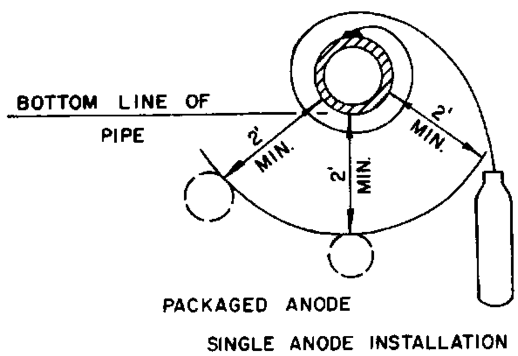

FIGURE 1: Anode Installation

To assure anode design life, the anode shall be placed so the wire end is not below the rest of the anode.

To avoid cathodic shielding and/or shorts, an anode shall not be placed so that a metal structure is between the pipeline and the anode.

Any damage to the copper wire insulation shall be repaired by taping. Clean and coat connections to the pipeline.

The anode wire should be fitted to the ditch bottom to prevent damage during backfilling.

Clean soil, free of sand or gravel, should be tamped around the anode. If the soil is not saturated with moisture, the packed soil around the anode may be soaked with water. Do not wet the anode directly. Care is necessary to prevent damaging the anode, copper wire, or wire insulation.

If the packaged anode is damaged so that the backfill material around the magnesium bar has displaced, do not use the anode. This shortens the life of the anode and reduces the protective current output.

2.3 Drive-In (Spike) Anodes

Drive-in anodes are typically 1- to 2-pounds of magnesium that may be used on an isolated short section of pipe such as an M&R setting, isolated service riser, etc. The drive-in anode is typically used to cathodically protect existing facilities as an alternative to installing a buried anode.

Connection to the structure is typically accomplished with a stainless steel band clamp provided by the manufacturer. Before the clamp is connected, the structure surface must be cleaned (free of debris and coating) for proper contact. An alternate connection method is to thermite weld the anode wire directly to the structure and properly coat the connection.

The anode should be driven into the ground at a location that is perpendicular to the structure. If the clamp is connected to the structure at an above ground location (i.e., riser), place the connecting lead wire in a location to reduce the chance of damage by an outside force.

3. INSTALLATION CONFIGURATIONS

3.1 Single Installation - Direct Connection

Where practical, the anode's lead wire should be tied around the pipe with a half-hitch connection prior to attachment to the pipeline to keep from pulling the connection loose. See Figure 2 below.

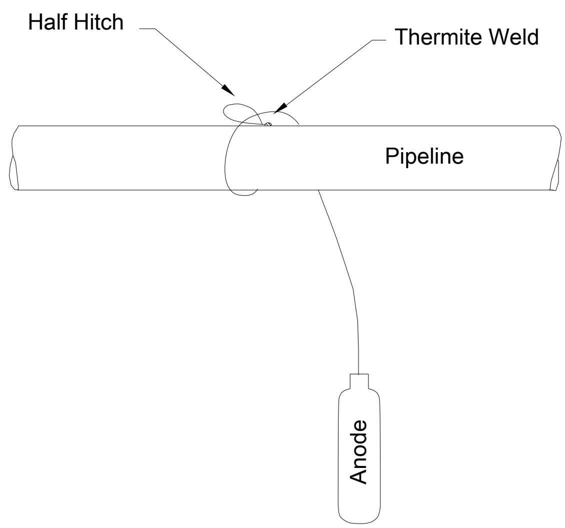

FIGURE 2: Anode Installation – Direct Connection

3.2 Multiple Installation - Gathering Wire

When installing multiple anodes, connect the anode's lead wire to a minimum size AWG #8 gathering wire with an approved splice connector. Properly coat the connection with an approved underground waterproof connector kit/product as directed by local corrosion personnel via Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” or equivalent documentation. When practicable, the anodes should be spaced as directed by corrosion personnel in order to minimize restriction to current output.

Install the gathering wire in such a manner as to protect it from external forces by installing it with a minimum 18 inches of cover and installing “CAUTION” (or equivalent) warning tape approximately 6- to 12-inches below the planned final grade. See Figure 3 below.

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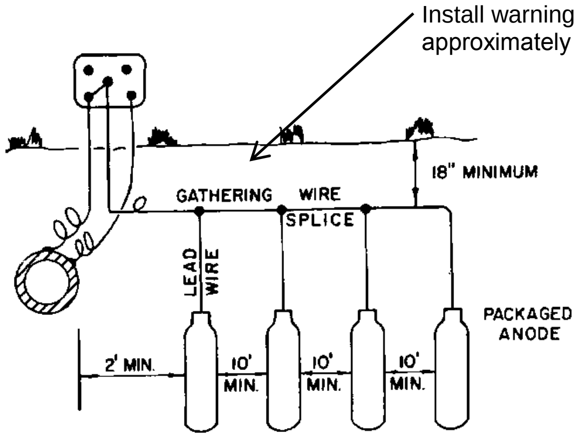

FIGURE 3: Multiple Anode Installation – Gathering Wire

4. RECORDS

The location of galvanic anodes installed shall be mapped and/or recorded within the Company’s work management system, or equivalent. Records or maps showing a stated number of anodes, installed in a stated manner of spacing, need not show specific distances to each buried anode.

These records or maps must be retained for as long as the pipeline remains in service.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Installation of Test Stations**	Standard Number: **GS 1420.520**
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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.471

1. GENERAL

Test stations shall be installed as indicated on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" and/or on the work order drawings or engineering plans.

2. TYPES OF TEST STATIONS

The basic types of test stations are listed below:

a. pipe-to-soil potential,

b. magnesium anode (single or multiple anode),

c. insulated joint,

d. continuity bond,

e. cased crossing,

f. stray current resistance bond,

g. magnesium anode drain,

h. line current flow (IR drop),

i. IR drop coupon, and

j. AC corridor.

Typical test station wiring diagrams are shown in GS 1420.095 "Corrosion Control Design - Test Stations," Exhibit A. Wiring details shall be specified by local corrosion personnel.

3. INSTALLATION OF TEST STATIONS

Test stations shall be installed in accordance with the following requirements and guidelines.

a. Install the test station for access, convenience, and safety. Install the test station in a location that will minimize hazards from tripping, plowing, mowing, etc. Above-ground test stations should be used where practical. Curb box type test stations should be located behind the curb line, where practical, to remove the test station from traffic lanes and to minimize the possibility of being paved over. Examples of an above-ground test station and a curb box type test station are shown in Exhibit A.

b. A minimum of two insulated copper conductive test leads of the same color shall be installed on each pipe section. Wires on different sections shall be identified by terminal connection, wire color, and/or labeling.

c. Each test lead wire shall be connected to the facility to remain mechanically secure and electrically conductive, and each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe. Connect one end of each test wire to the pipe by the thermite weld process. Refer to GS 1420.580 “Thermite Weld Process” for additional guidance.

d. Tie the test wires around the pipe with a half hitch connection (see Exhibit A) and install them so that they follow the bottom contour of the trench. If tying the test wires around the pipe is not practicable (e.g., as with keyhole excavations), provide some slack in the test wires so there is minimum tension and wire movement at the weld connection during the backfill operation.

e. When installing test leads, the bared test lead wire and the facility will be recoated with an electrical insulating material compatible with the coating and wire insulation. This coating material shall be specified by local qualified corrosion personnel (“qualified” according to GS 1400.010 “Corrosion Control - General”). Refer to GS 1420.580 “Thermite Weld Process” for additional guidance.

f. Test wires shall be extended to the height of the terminal box. Wires should be coiled and long enough to allow 12" of extension above the terminal box.

g. Splicing should be kept to a minimum. If splicing is needed, use an approved splice kit and install according to manufacturer’s instructions.

h. Test wire connections shall be clearly identified or labeled, or follow a recorded wire coding or connection convention.

i. Provide support, as necessary for above ground stations by wood post, line marker, etc. However, do not attach the test station to a utility pole.

j. Remove sharp edges from conduit ends by reaming or filing. A plastic disc, section of plastic pipe, section of garden hose, etc. can be used at the conduit end to prevent damage to test wires.

k. Test stations shall be located with respect to permanent land marks with at least two measurements noted on the test station record.

3.1 Installation of Test Stations within an AC Corridor

When installing a test station within an AC corridor (e.g., near electric transmission lines, within stray current areas), additional precautions should be taken to minimize electrical shock due to AC stray current. These additional items should be installed at the direction of local corrosion personnel:

a. a test station box with a “dead front” design, which eliminates exposed metallic surfaces, and/or

b. a voltage gradient mat, which equalizes the potential difference between you and the pipeline.

Refer to GS 1420.120 “Controlling AC Stray Current” for additional guidance.

4. RECORDS

Existing Company forms shall be used to document test station wiring and location information. In addition, each new test station installed or replaced shall be recorded within the Company’s work management system, or equivalent, for the life of the test station. Test station locations should also be recorded on Company inventory maps/GIS. Refer to GS 1430.020 “External Corrosion Control Monitoring” for the retention requirements of test station monitoring information.

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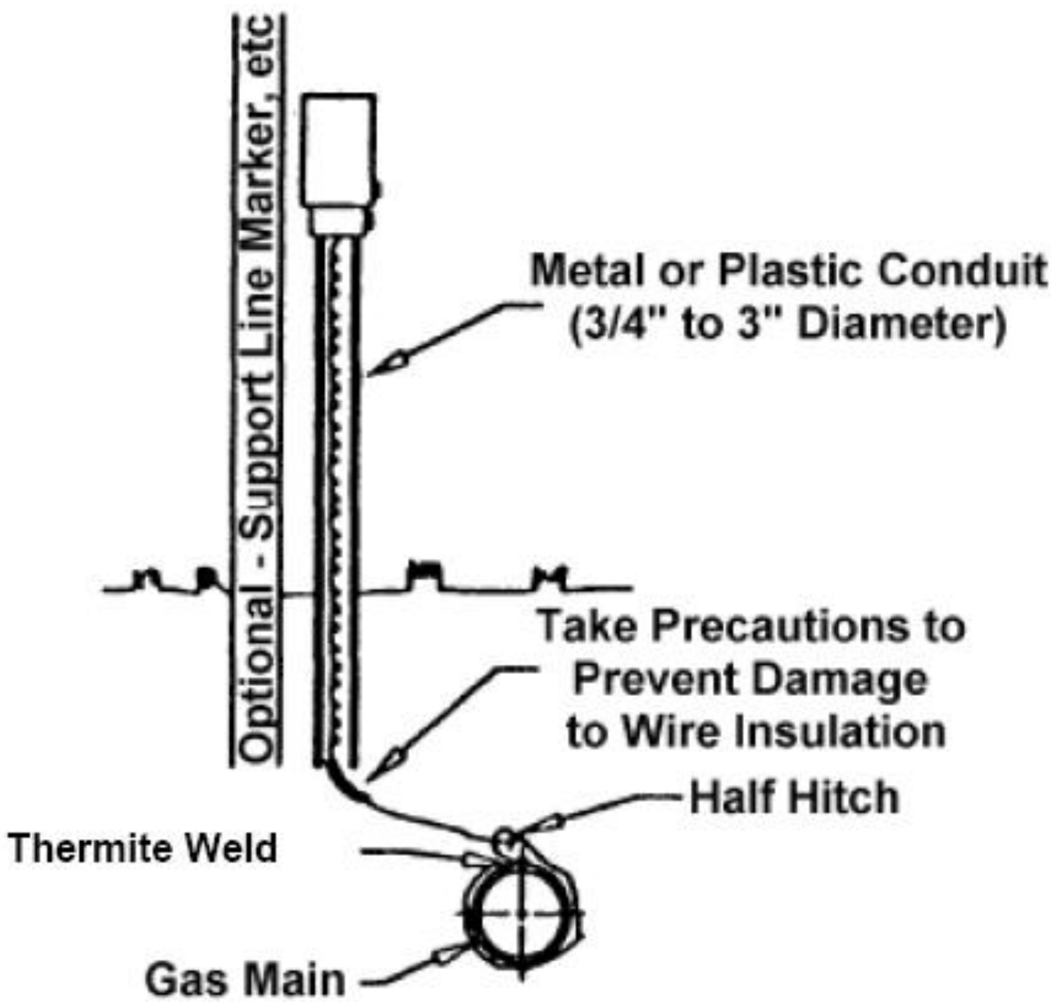
EXHIBIT A
(1 of 2)

Above Ground Test Station



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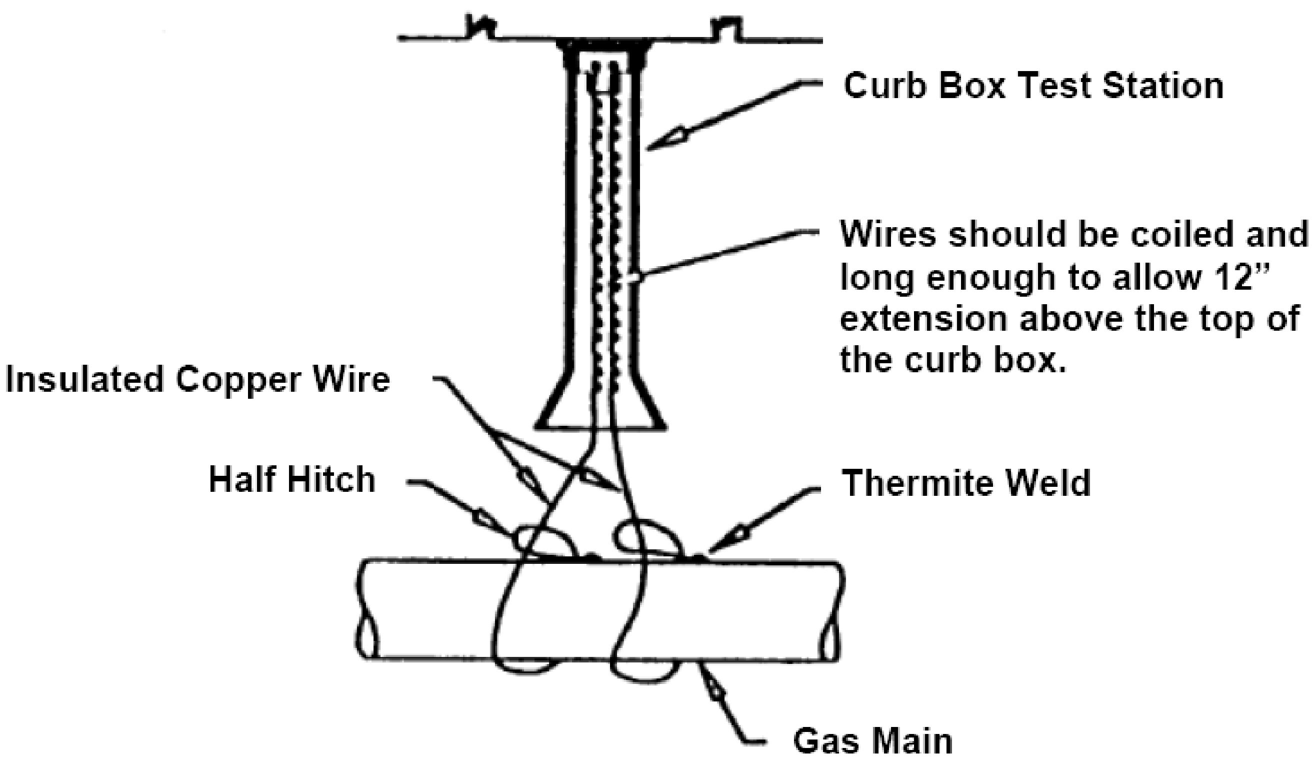
Curb Box Test Station



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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Installation of Insulators	Standard Number: **GS 1420.530**
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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

This standard provides guidance on the installation of insulators for cathodic protection purposes.

Insulators shall be installed as indicated on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” and/or as directed by local corrosion personnel.

Prior to installation of an insulator, test the insulated fitting to ensure that the insulator is working. Refer to GS 1430.250 “Verifying Electrical Continuity and Isolation” for testing guidance.

After installation and prior to backfilling an insulator, the following shall be performed:

a. coat metallic insulated fittings,

b. coat all exposed bare piping within the bell hole,

c. test insulated fittings to ensure that insulation has been achieved (refer to GS 1430.250 “Verifying Electrical Continuity and Isolation”), and

d. install test stations at buried insulators as indicated on Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements” and/or as directed by local corrosion personnel. Refer to GS 1420.520 “Installation of Test Stations” for further guidance.

The sections below include installation guidelines for different types of insulators.

2. WELD-END INSULATORS

Care must be taken to avoid excessive stress on manufactured weld-end insulators. They are relatively strong in pull-out or straight compression, but they may leak if deflected or placed in a bending moment.

Regardless of the type of weld-end insulating fitting used to make insulated joints, the following precautions should be taken to reduce the chance of inducing a bending stress failure.

a. Weld-end insulated fittings shall be supported on firm tamped or undisturbed ground. The pipe ends being joined shall be in axial alignment to minimize deflection.

b. Weld fittings shall be used when making changes in direction in order to install weld-end insulated connections at grade or level of mains. See Exhibit A.

c. Weld-end insulating fittings shall not be welded directly to three-way tees (e.g., Shortstopp tee).

d. Weld-end insulating fittings should be installed no closer than ten times the pipe diameter to any in-line weld fitting, to provide adequate space for bypass fittings to remove a faulty insulator, if necessary, unless the adjacent pipe provides the adequate space.

e. Adequate support must be provided to both the fitting and adjoining pipe to keep stress off the fitting.

f. Use a backfill material which will compact well, such as sand, sandy-loam soil, sand-gravel mixture (bankrun), screenings, etc. Heavy or wet clays and frozen earth are not suitable for bedding pipe at insulating connections.

Welding on weld-end insulating fittings shall be made by electric arc welding (oxyacetylene welding is prohibited). When welding, precautions shall be taken to prevent overheating or shorting the insulating fitting. To prevent overheating, the use of wet rags or cold water is helpful for this purpose. The temperatures of the insulating fitting should be such that it can be handled with bare hands. To prevent shorting the fitting, the weld ground shall be affixed on the same side of the insulator as the weld.

Two types of weld end insulators, a manufactured weld end insulator and a pre-fabricated flange assembly, are illustrated in Figures 1 and 2 below.

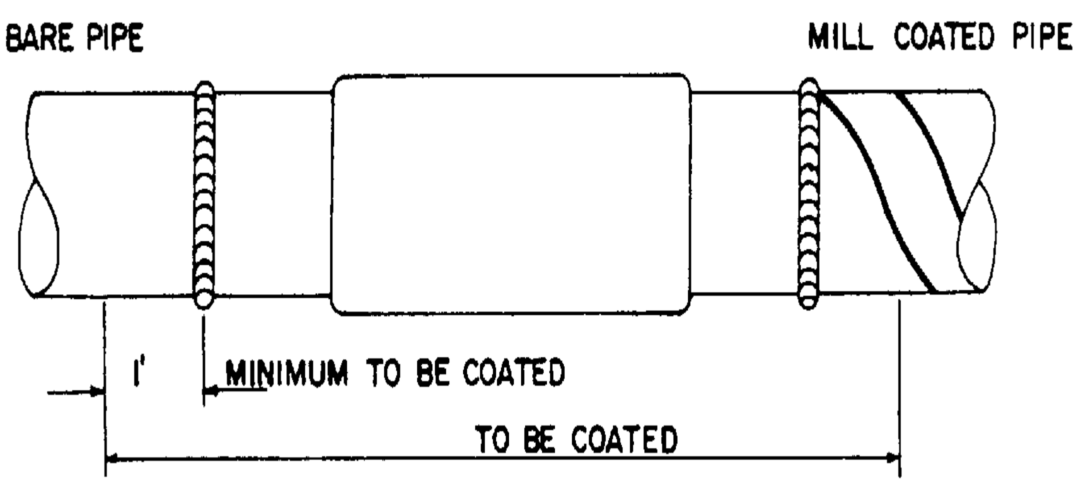


FIGURE 1: MANUFACTURED WELD END INSULATOR

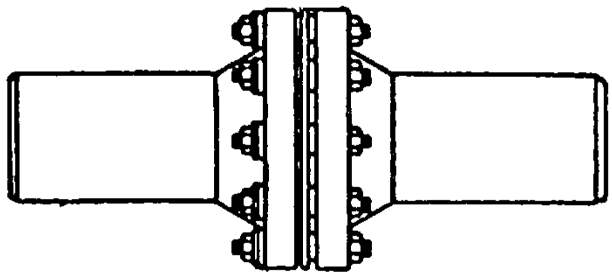


FIGURE 2: SHOP FABRICATED FLANGE INSULATOR

3. INSULATED FLANGES

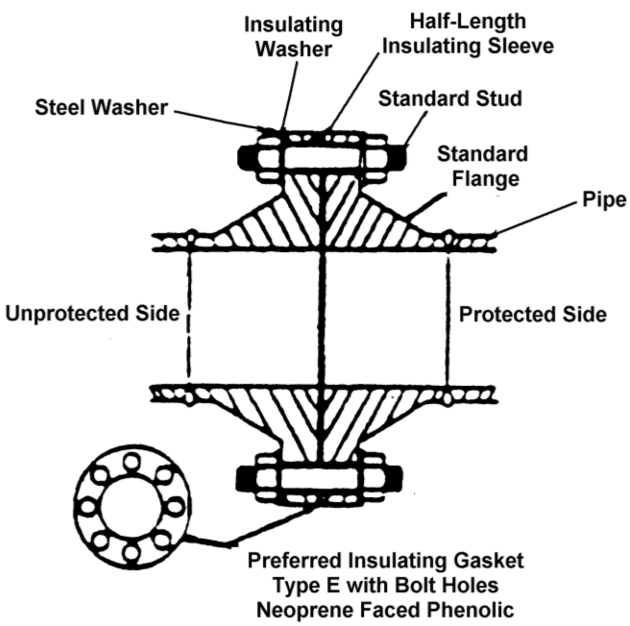
At times, it may be necessary to install insulation at tie-in flanges above or below ground. At the direction of local corrosion personnel and/or via Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements,” an approved flange insulation kit for above or below ground use, as appropriate, shall be installed according to manufacturer’s specifications.

On existing flanged joints, where insulation is required and it is impractical to separate the flanges, bolt sleeves and insulated washers may be sufficient to provide insulation. Sleeves and insulating washers may be installed in an in-service flange by removing one bolt at a time from the flange and replacing with bolt, sleeve, and washers.

In order to provide cathodic protection to the bolts, install the insulating washer on the unprotected side of the flanged fitting, so that the bolts are protected with the cathodically protected pipe section. Refer to Figure 3 below.

A back-up wrench should be used to ensure that the bolt does not turn during tightening. Turning can destroy an insulated sleeve and make an insulated flange ineffective.

Where the flanges can be separated to remove the existing gasket, insulation can be accomplished as seen in the illustrations in Figure 3 below.



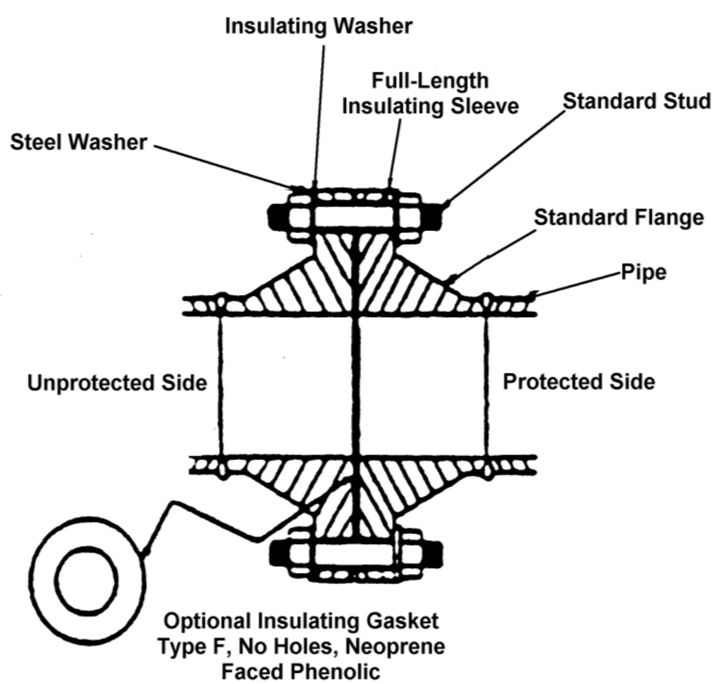


FIGURE 3: PREFERRED AND OPTIONAL METHODS TO INSULATE AT FLANGES

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4. INSULATING COUPLINGS

Insulating couplings are not the preferred method for providing insulation between cathodically protected and unprotected pipe. However, they are typically installed to provide insulation when making a tie-in between cast iron and steel pipe.

Insulating couplings are classified as either bolted or compression.

Mechanical couplings should not be used except where the confines of the excavation or safety considerations dictate their use over welding or plastic fusion. Insulating couplings are acceptable for both above ground and below ground use in systems designed to operate at 60 psig or less.

Refer to JM 1320 “Mechanical Coupling Connections” for general installation guidance, along with manufacturer’s instructions.

A typical insulating bolted coupling is illustrated below in Figure 4.

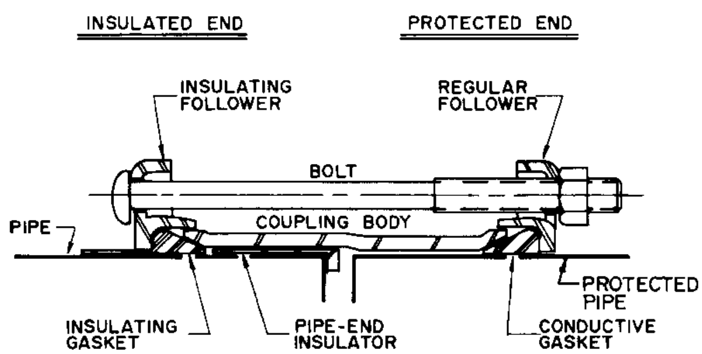

FIGURE 4: INSULATING BOLTED COUPLING

An insulating compression end coupling is illustrated below in Figure 5.

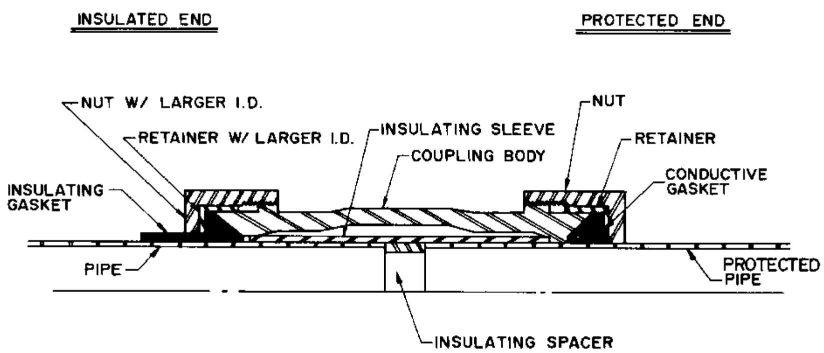

FIGURE 5: INSULATING COMPRESSION END COUPLING

Proper alignment is necessary to avoid damage to the insulating coupling. Where the ability to assure proper alignment is in doubt, an additional non-insulating coupling should be used to make the tie in, minimizing the deflection. The non-insulating coupling should have a continuity bond installed to insure that the short section of pipe between couplings does not become isolated. Bonds should only be installed at the direction of corrosion personnel.

Normally, insulating couplings are not designed to sustain longitudinal pullout or thrust forces. Reinforcing insulated straps shall be installed on the pipe across the insulating coupling where there is a possibility of the pipe pulling out of the coupling. Refer to JM 1320 “Mechanical Coupling Connections” for strapping guidelines.

In order to provide cathodic protection to the reinforcing straps and/or to the coupling, install the insulating gasket and/or insulating washer on the unprotected side of the coupling, so that both the coupling and the reinforcing straps are protected along with the cathodically protected pipe section. Refer to Figures 6 & 7 below, which show the correct installation method for reinforcing insulating couplings.

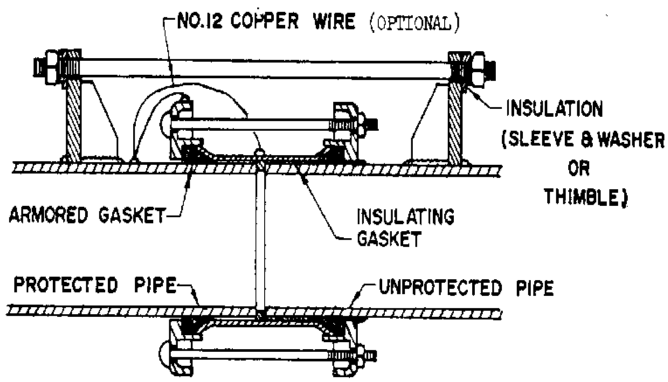

FIGURE 6: REINFORCED INSULATED STRAP

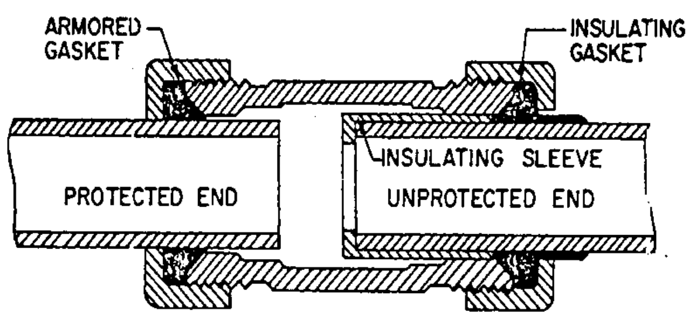

FIGURE 7: STYLE 90 INSULATED COUPLING

5. LIVE (HOT) LINE INSULATORS

Live line insulators, "Hot Line," as illustrated below, may be used to insulate existing sections of piping systems without service interruption. The fittings are used with a conventional tapping machine equipped with a shell cutter or hole saw which completely severs the pipe inside the fittings. The assembly of hot line insulators shall be completed according to manufacturer's instructions.

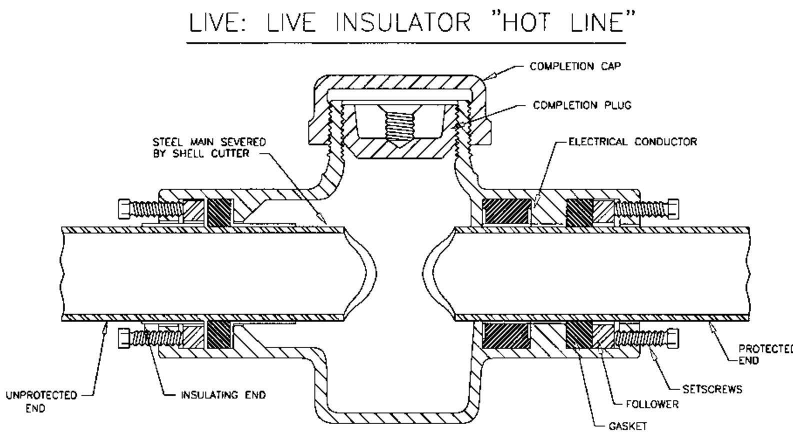

FIGURE 8: LIVE "HOT LINE" INSULATOR

The live line insulator is a compression type fitting and has the same pullout limitation as a compression coupling. A live line insulator, like other compression fittings, should not be used in areas subject to pullout caused by movement or external loading. The fitting should be installed with care. Lubricate gaskets and gasket seating areas of the fitting with soapy water. Lubricate bolt threads and tighten diametrically opposite bolts uniformly and progressively. Prior to cutting the line, an air test at 90 psig should be conducted to ensure that no leaks exist in the fitting.

Upon severing the pipe, the insulation should be checked since insulation may not be achieved with the use of this fitting if the line is in considerable compression. Considerable compression could cause the severed sections to move together. Reinforcing insulated straps shall be installed on the pipe across the live line insulator where there is a possibility of the pipe sections touching or pulling out of the fitting. Refer to JM 1320 "Mechanical Coupling Connections" for strapping guidelines.

NOTE: Bond wire is not required since the sleeve has internal devices for electrical conductivity. If additional bonding is desirable, attach bond wires to one of the side bolts using a second nut. Bonds should only be installed at the direction of corrosion personnel. DO NOT WELD OR BRAZE BOND WIRES TO SLEEVE.

6. UNIONS

Insulated unions are approved for above ground use only. During installation, they shall be checked to ensure proper operation with an approved instrument.

When there is potential for vibration, center punch the insulated union at the union nut to prevent loosening.

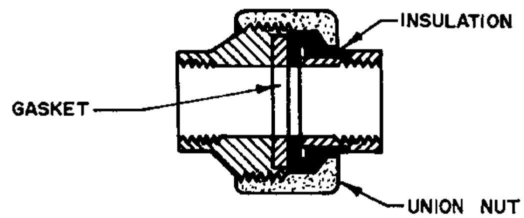

FIGURE 9: INSULATED UNION

7. METER INSULATORS

Meter insulators are designed to electrically insulate the Company piping and/or customer service line from the customer house line. A meter insulator must be installed so that a metallic connection (gas grill or gas light line, vent piping, house lines, etc.) does not exist across the meter insulation. When the service line or gas carrying portion of the riser is metallic, the meter insulator shall be electrically tested with an approved instrument (refer to GS 1430.250 "Verifying Electrical Continuity and Isolation") after installation to ensure that the insulator is working properly.

The types of meter insulators are: insulated meter bars; insulated meter barrels; insulated meter swivels; insulated unions; insulated flanges; insulated couplings; or insulated union type meter valves.

When a meter insulator is required, use all of the pieces in the assembly. Do not omit installing any of the parts.

8. PLASTIC PIPE

Installation of sections of plastic pipe of less than 5 feet between metallic mains is prohibited regardless of purpose. Therefore the installation of plastic pipe for insulating purposes shall be at a length of 5 feet or greater.

9. OTHER INSULATOR MATERIAL

Electrical insulating materials are also needed to maintain isolation from bridge structures, casings (refer to GS 3010.070 or GS 3010.070(MA) "Casing"), and other structures.

Insulating type casing spacers are used to maintain separation between casing and carrier pipe.

Insulated pipe rollers are used to insulate steel mains from bridge structures. Insulators for adjustable roller hangers are used to insulate the pipe and hanger assembly from the bridge structure.

Fiberglass reinforced plastic (FRP), or another similar approved material, is used to insulate against possible contact with other structures. A typical use of FRP is at regulator stations constructed onto concrete or metal supports, so that the concrete or metal does not damage the pipe coating. See Figure 10 below. FRP, or another similar approved material, shall be the only material to be used in these instances.

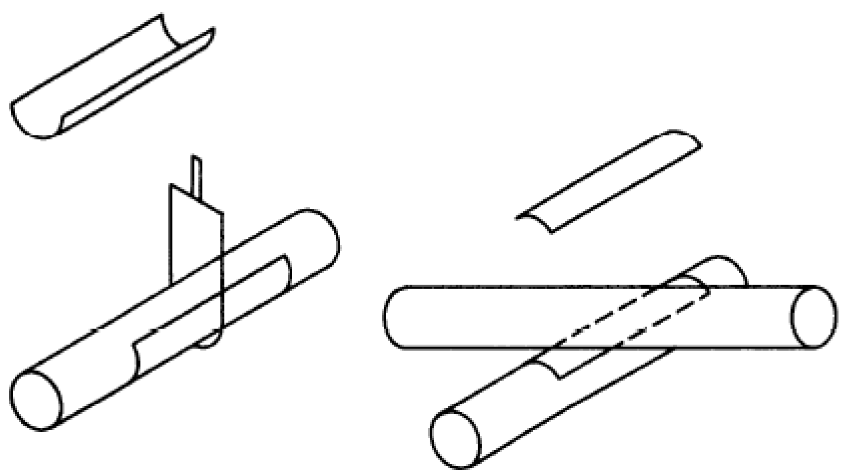

FIGURE 10: INSULATION FROM CONTACT WITH OTHER STRUCTURES

10. RECORDS

The location of insulators used for cathodic protection purposes in main lines shall be recorded on Company inventory maps/GIS. Refer to GS 1430.020 “External Corrosion Control Monitoring” for the retention requirements of test station monitoring information for buried insulators.

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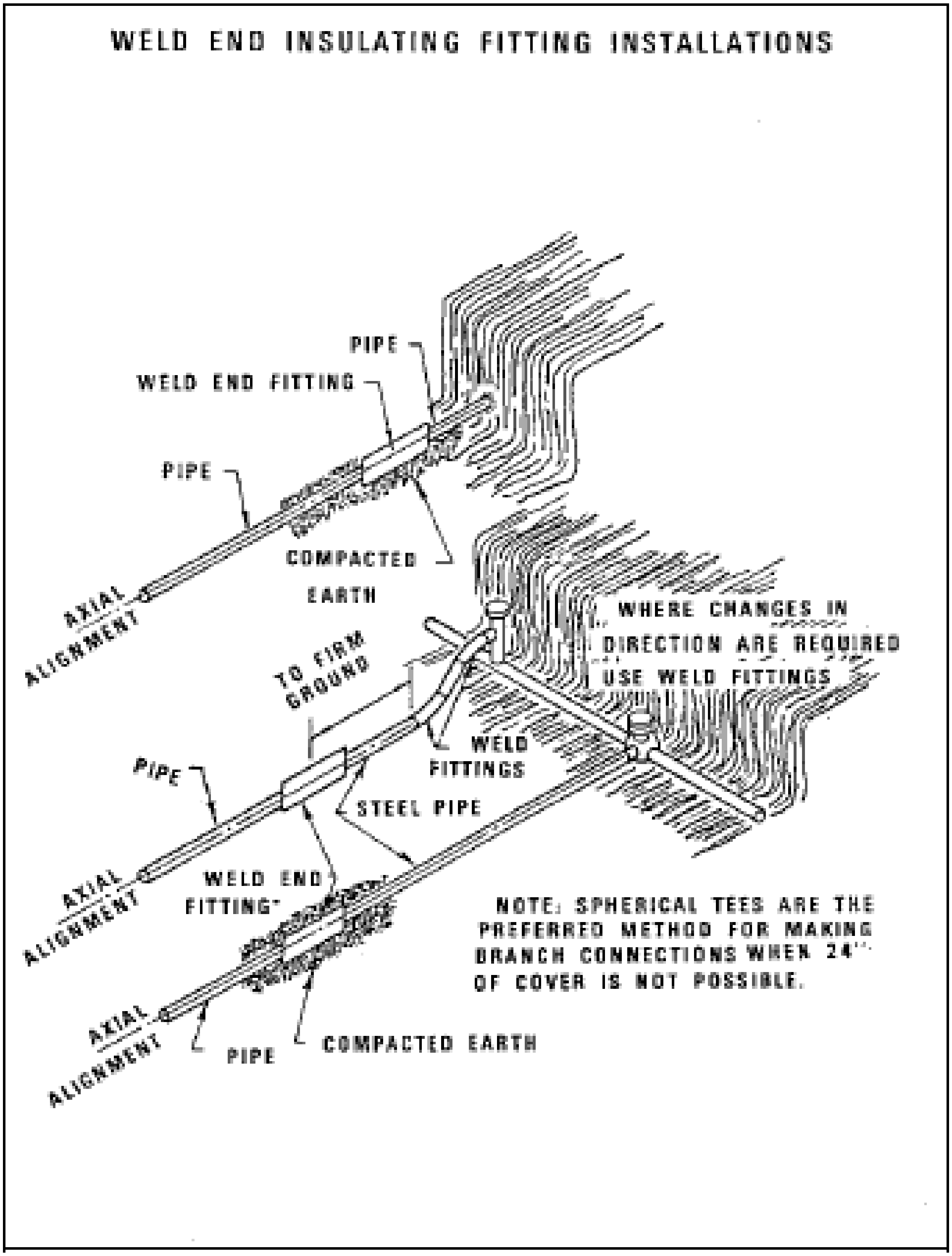
EXHIBIT A



NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Installation of Bonds	Standard Number: **GS 1420.540**
Supersedes: 01/01/2014		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.473, 192.491

1. GENERAL

A bond provides a path for current flow. Bonds shall be installed only at the direction of qualified corrosion personnel. The bond type, size, and wire coating shall be specified by qualified corrosion personnel.

2. CONTINUITY BONDS

A continuity bond is a metallic connection made to provide electrical continuity around high resistance pipe joints, such as compression type couplings.

All bond wires shall be connected by the thermite weld process (refer to GS 1420.580 “Thermite Weld Process”) and/or other approved methods such as weld straps per GS 1320.010 “Mechanical Coupling Connections or via un-insulated bolts). All bond connections shall be coated according to GS 1420.035 “Coating Repair Methods for Mill Applied Coatings.”

When required, bolted couplings shall be bonded by connecting a minimum #8 insulated copper wire across the coupling. A minimum size #12 insulated wire shall also be connected between the center ring or barrel and one of the pipe sections on bolted couplings. Also, one follower should be bonded to the pipe, where practical. Figure 1 depicts an approved installation method.

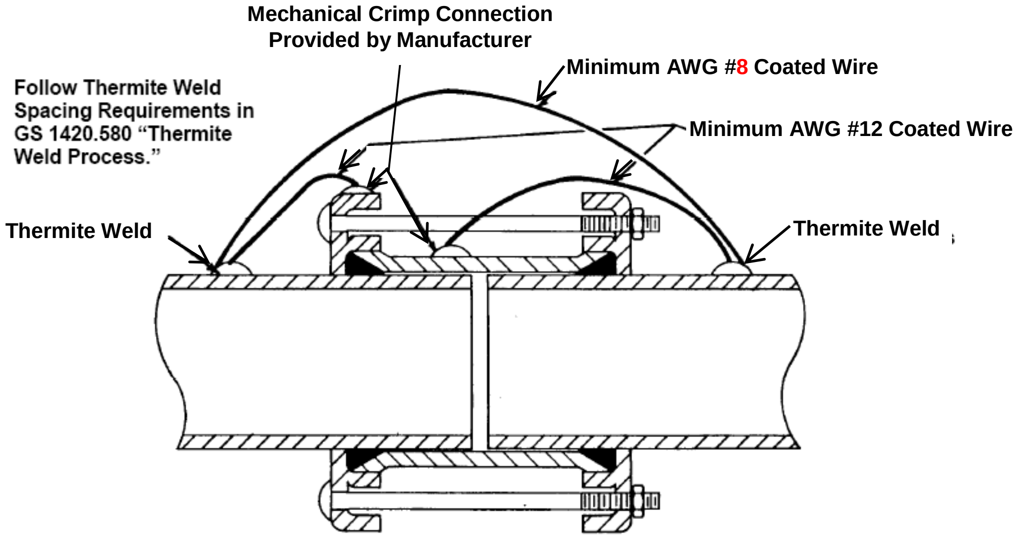


FIGURE 1: CONTINUITY BOND ACROSS A BOLTED COUPLING

Split sleeves and similar type fittings may be bonded to the pipeline by connecting one end of the bond wire to the pipe with a thermite weld and the other end to the fitting mechanically. An extra nut on one bolt may be used for the mechanical connection. Figure 2 depicts an approved installation method.

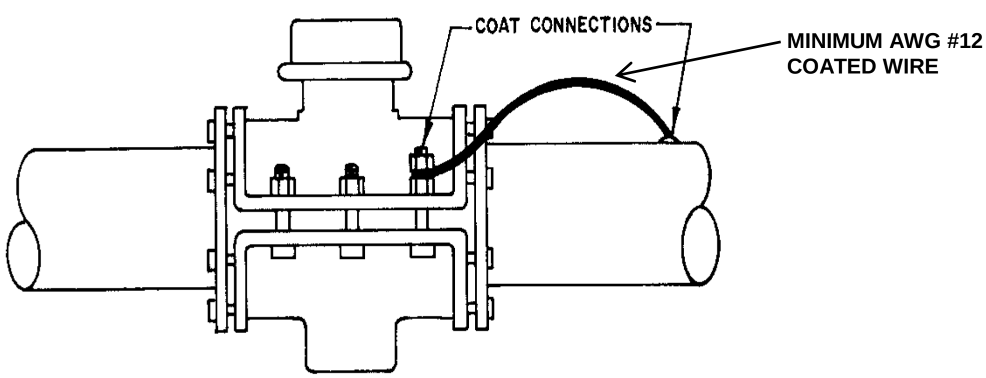


FIGURE 2: CONTINUITY BOND FOR A SPLIT SLEEVE

Insulated fittings, such as insulating couplings, insulated flanges or weld-end insulators, that are required to be bonded, shall have the bond connected through a test station (refer to GS 1420.095 "Corrosion Control Design – Test Stations"). Figure 3 depicts an approved installation method.

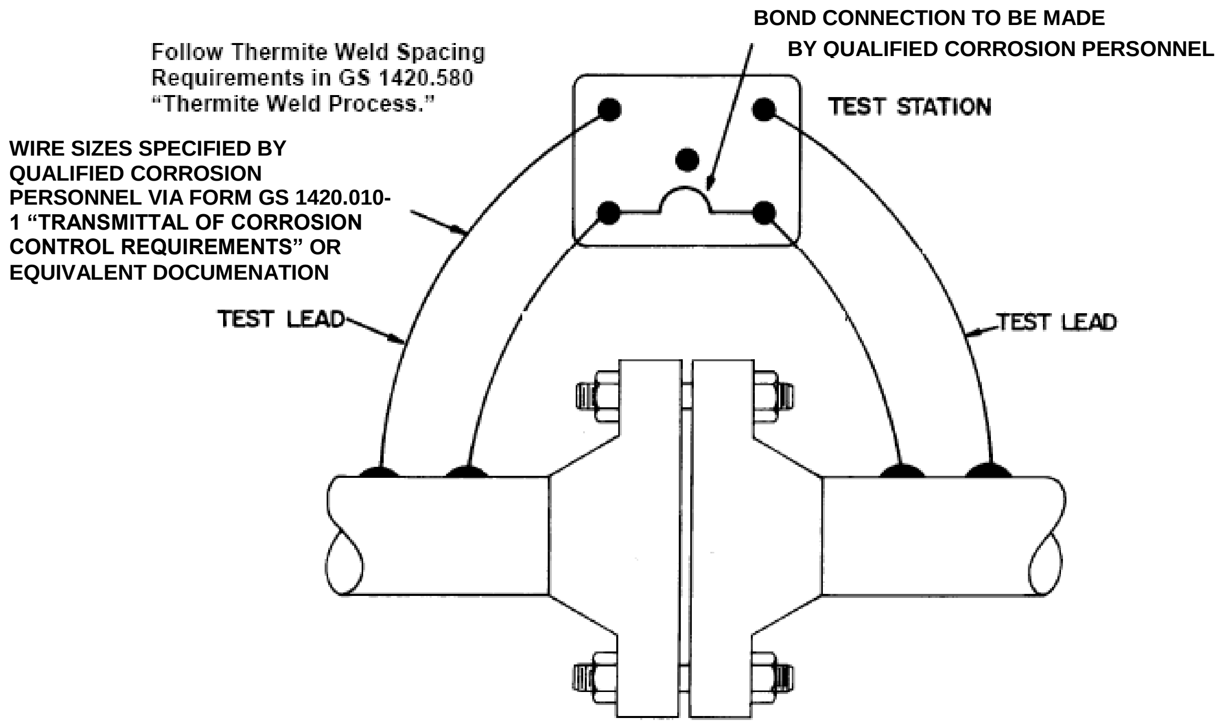


FIGURE 3: CONTINUITY BOND ACROSS AN INSULATING FITTING

3. INTERFERENCE BONDS

An interference bond is a metallic connection designed to provide for control of electrical current interchange between pipelines, or between sections of a pipeline.

All interference bonds shall be designed by qualified corrosion personnel. A minimum size AWG #8 insulated wire should be used for bonds made in an impressed current system, in stray current areas, or for interference bonds. Larger bond wires may be necessary in stray current areas (e.g., mining areas, street car railway systems). In some stray current areas, a bond may be installed in conjunction with a reverse current switch.

Interference bonds shall be connected within a test station. All bond wires shall be connected to the pipelines by the thermite weld process. All bond connections shall be coated according to GS 1420.035 "Coating Repair Methods for Mill Applied Coatings." Figure 4 depicts the correct installation method.

The location and wire configuration of the interference bond shall be selected by qualified corrosion personnel. The bond wire configuration shall be clearly marked, identified, and documented with respect to ownership. Field changes to corrosion recommendations shall be approved by qualified corrosion personnel.

Bonds to foreign structures shall not be made without obtaining permission from the owner of the structure. The physical connections shall be made by the owner unless the owner specifically requests the Company to make the connection.

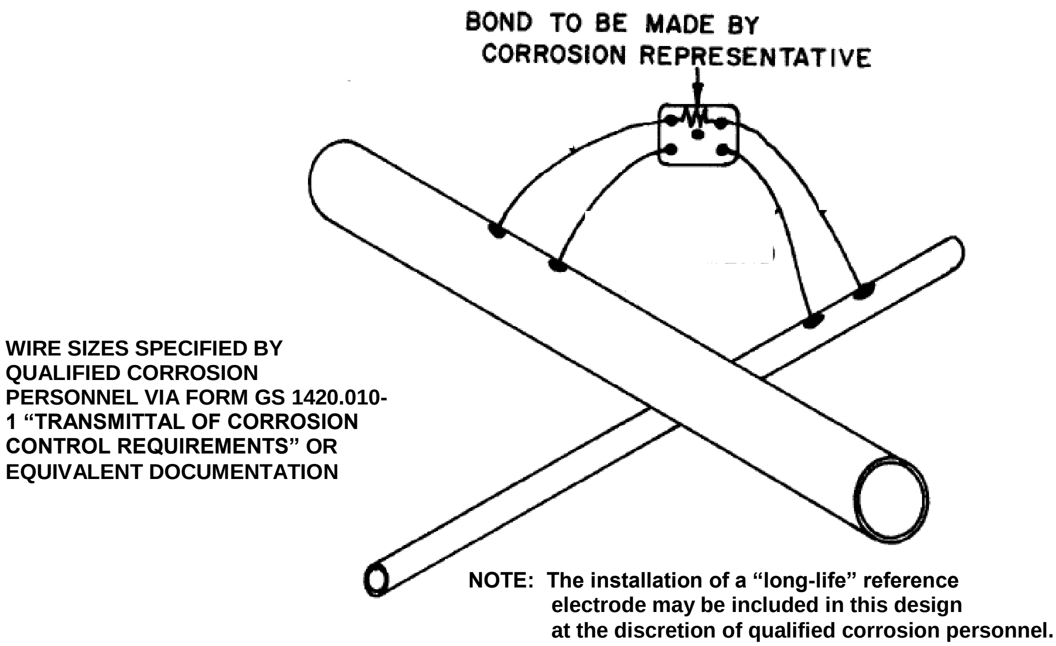


FIGURE 4: INTERFERENCE BOND

4. RECORDS

The location of interference bonds used for cathodic protection purposes should be recorded within the Company's mapping system. Interference bonds shall be recorded in the Company's work management system, or equivalent. Refer to GS 1420.030 "External Corrosion Control Monitoring" for the retention requirements of test station monitoring information for bonds.

The location of continuity bonds between otherwise isolated facilities or isolated sections of pipeline bonded through a test station should be recorded within the Company's mapping system, but shall be recorded in the Company's work management system, or equivalent, as a test station or test point for future adjustments and troubleshooting and referenced on existing applicable test point records, as necessary.

Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Installation of Impressed Current Systems	Standard Number: GS 1420.550
Supersedes: 03/01/2010		Page 1 of 9

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

This standard provides guidance on the installation of impressed current systems and associated ground beds, which shall be installed at the direction of corrosion personnel.

The design and material application for impressed current system components shall be specified by qualified corrosion personnel via Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements.” A person meets the requirements of qualification through education, training, and/or experience in corrosion control.

2. RECTIFIERS

All rectifiers shall be of a type designed and approved for cathodic protection installations and shall be installed in accordance with the National Electrical Code and with the local power company’s requirements. A cable identification system shall be used to assure that the gathering wire to the ground bed is connected to the positive terminal of the rectifier. Rectifiers shall be installed to meet the following specifications.

a. Install an on-off switch and fuse or circuit breaker external to the rectifier case.
b. The rating of the external fuse or circuit breaker shall be determined in accordance with the National Electric Code and/or local electric code.
c. Electrically ground the rectifier case.
d. Mount the rectifier case at a convenient height, which is high enough to avoid mechanical, livestock, or water damage.
e. Install the rectifier case so that adequate ventilation is possible.
f. Place AC and DC wiring in separate conduits.
g. Install a Company approved lock on the rectifier case and switch box.

A typical rectifier installation is shown in Exhibit A.

3. SOLAR POWERED IMPRESSED CURRENT SYSTEMS

Solar powered impressed current systems shall be installed according to manufacturer’s installation instructions.

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4. IMPRESSED CURRENT GROUND BEDS

Graphite anodes, durichlor anodes, mixed metal oxide, or abandoned steel pipe may be used for an impressed current ground bed. Good construction practices are required if impressed current ground beds are to work efficiently.

4.1 Cables and Connections

Lead wires and gathering wires should be buried to a minimum depth of 18" to protect them from mechanical damage. Splice connections shall be held to a minimum and made as prescribed in Section 5 below. The cable-to-anode connection for deep anode ground beds and for abandoned pipelines when used as an anode should be above ground. If the connection must be made below ground it shall be well coated. It is recommended to make the connection in an electrical box to isolate the connection from soil and water.

4.2 Horizontal Anodes- Standard Design

If pre-packaged anodes are used, install according to manufacturer's instructions.

If conventional impressed current anodes are used, they should be installed in the horizontal position surrounded with a minimum of 200 pounds of coke breeze, but as directed by corrosion personnel, in accordance with the following guidelines.

a. Dig the anode hole at the designated location to the required depth and size. The anode hole may be in or adjacent to the gathering wire trench. The minimum anode hole size should be 24 inches longer and eight inches wider than the anode itself.

b. Fill the bottom of the anode hole with four inches of approved coke breeze. Tamp the coke breeze in place.

c. Center the anode in the hole. Cover with a minimum of four inches of coke breeze firmly packed in place.

d. Connect the anode lead wire to the gathering wire with an approved splice connection. Properly coat the connection with an approved underground waterproof connector kit/product as directed by local corrosion personnel via Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" or equivalent documentation.

e. Inspect the wire insulation for damage, and repair as required.

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f. Fill the gathering wire trench and anode hole with enough earth to allow for settling, or tamp to prevent settling.

g. Inspect to ensure that the anodes are not broken and the lead and gathering wire are not damaged during digging, tamping, or backfilling operations.

A typical type of installation is shown below in Figure 1.

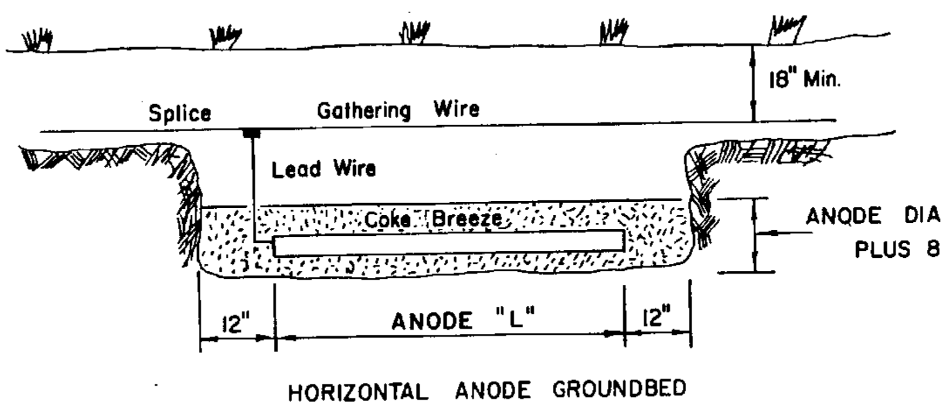

FIGURE 1: HORIZONTAL ANODE GROUND BED

4.3 Vertical Anodes

If pre-packaged anodes are used, install according to manufacturer's instructions.

If conventional impressed current anodes are used, and where horizontal placement is not practical, impressed current anodes may be installed vertically in accordance with the following guidance.

a. Bore or drill the anode hole at the designated location to the required depth and size. The anode hole may be adjacent to or in the gathering wire trench. The minimum size hole should be eight inches wider and 24 inches deeper than the anode itself.

b. Fill the bottom of the anode hole with a minimum of 12 inches of well-tamped or heavy slurry coke breeze.

c. Center the anode in the hole while providing approximately four inches of tamped coke breeze around and 12 inches of tamped coke breeze on top of the anode.

d. Connect the anode lead to the gathering wire with an approved type splice connection.

e. Fill the gathering wire trench and anode hole with enough earth to allow for settling, or tamp the earth to prevent settling. In heavy soils or clay, it is recommended that gravel be used near ground surface to provide for venting.

f. Inspect to ensure that the anodes are not broken and the lead and gathering wire are not damaged during installation.

A typical type of installation is shown below in Figure 2.

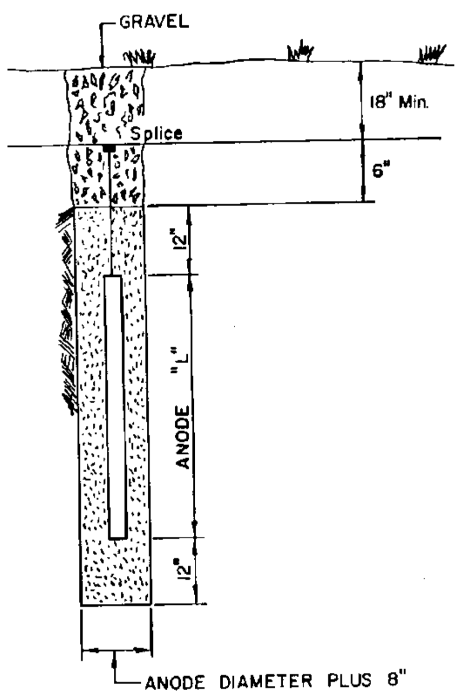

FIGURE 2: VERTICAL ANODE GROUND BED

4.4 Deep Ground Beds

Deep ground beds are normally used in areas of limited right of way.

Typically the anode column shall be drilled at depths greater than 80 feet to 300 feet, with a minimum diameter of 6”.

Anodes should be placed at a designed spacing (as provided by corrosion personnel via Form GS 1420.010-1 “Transmittal of Corrosion Control Requirements”) to allow the maximum anode output in low soil resistance areas.

Vents (e.g., All-vent) shall be used to allow gases to escape. The vent lines shall exit the ground above expected flood levels.

All coke breezes shall be slurred, according to manufacturer’s installation instructions, when placed in and around the anodes in the anode column.

No splicing is permitted within the anode column. If any damage is found on the anode cable, then replace the anode.

An example of a deep ground bed is shown in Exhibit B.

5. SPLICE CONNECTIONS

Splice connections should be held to a minimum.

Where a splice connection is needed, make the connection with a mechanical or hydraulic crimping tool, split-bolt connector, or by the thermite weld process (see GS 1420.580 “Thermite Weld Process”). Connectors must be made of copper or brass and must be of the proper size for the wire being connected.

Sufficient insulation should be removed from the wire to permit proper installation of the connector. Exercise care, so as to not damage the conductor when removing the insulation.

Clean splices used in an impressed current groundbed by lightly sanding the cable insulation and encapsulating with an approved splice kit.

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Typical types of splice connections are shown below in Figure 3.

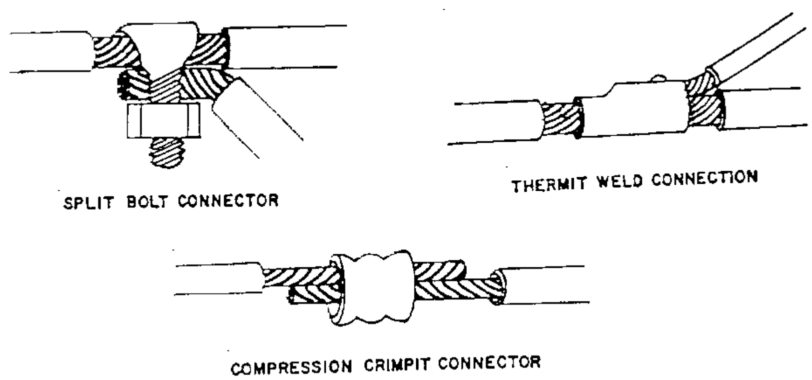

FIGURE 3: TYPICAL TYPES OF SPLICE CONNECTIONS

6. RECORDS

The location of impressed current systems and associated ground beds shall be recorded within the Company's mapping system. Impressed current system and ground bed information (e.g., type, size, and spacing of anodes installed; pounds of coke breeze installed; cable size) shall also be recorded in the Company Work Management (WM) system, or local corrosion files (e.g., circuit pack file). Refer to GS 1430.020 "External Corrosion Control Monitoring" for the retention requirements of impressed current inspection and monitoring information.

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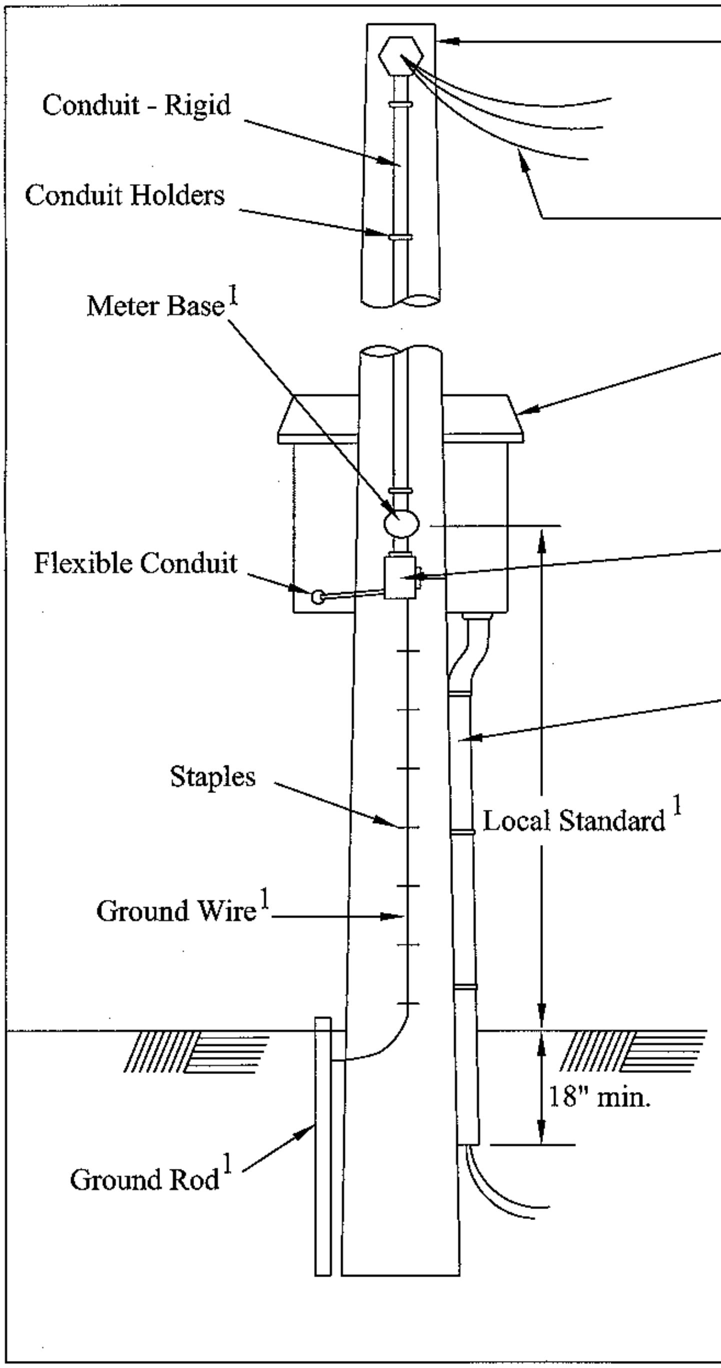
Distribution Operations

Gas Standard

Effective Date: 03/01/2010	Installation of Impressed Current Systems	Standard Number: GS 1420.550
Supersedes: N/A		Page 7 of 9

EXHIBIT A



Notes:

1. Refer to local electrical code for specifications

2. Switch box must be grounded

3. Rectifier case should be labeled with "Caution - High Voltage" or similar warning

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Gas Standard

Distribution Operations

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EXHIBIT B
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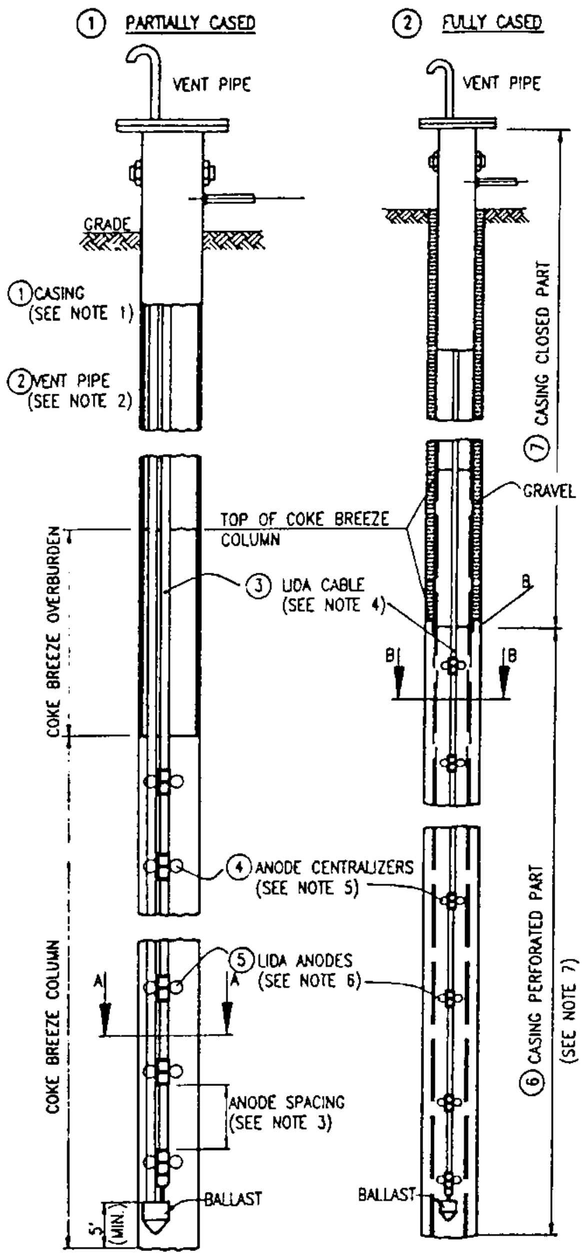


MATERIAL LIST

1. CASING NON METALLIC DIA. RANGE 6"-8" OR COATED STEEL SAME DIA.
2. PIPE 0.8" DIA. PVC OR PE FLEXIBLE PERFORATED
3. CABLE UDA CABLE
4. ANODE CENTRALIZERS GALVANIZED CARBON STEEL ANODE DIA. 1"
5. ANODE UDA TUBULAR 1" DIA. x 40" LONG CONNECTED ON UDA CABLE
6. CASING NON METALLIC DIA. HALF OF THE BORE HOLE DIA. PERFORATED OPEN SURFACE 25%
7. CASING NON METALLIC DIA. HALF OF THE BORE HOLE DIA. NON-PERFORATED
8. JUNCTION BOX (IF REQUESTED)
   1 TERMINAL FOR ONE UDA STRING DGB
   2 TERMINALS FOR TWO UDA STRINGS DGB
9. TUBE PVC 3" DIA. TWO ENDS THREADED
10. BLOCKAGE RINGS PVC INTERNALLY THREADED FOR 3" PVC PIPE
11. TIE CABLE 13.75" LONG NYLON
12. POLE WOOD 6" DIA.
13. COUPLING NON METALIC PVC INTERNALLY THREADED FOR THE ① DIA.
14. BACKFILL PETROLEUM CALCINATED COKE BREEZE

NOTES

① THE CASING HAS TO BE INSTALLED ACROSS ALL THE COLLAPSABLE STRATA TO REACH STABLE STRATA BELOW THE GROUND WATER STATIC LEVEL

② THE FLEXIBLE 1" DIA. PLASTIC VENT PIPE SHALL HAVE HOLES (0.2"-0.118" DIA.) DRILLED OVER THE FULL LENGTH OF THE VENT PIPE THAT IS TO BE EMBEDED IN THE COKE BREEZE BACKFILL

③ THE DEPTH OF THE HOLE AND THE QUANTITY OF ANODES INSTALLED IN INDIVIDUAL GROUND BEDS SHALL BE DETERMINED BY THE SPECIFIC JOB REQUIREMENTS

④ THE UDA CABLE HAS A DUAL INSULATION

⑤ ONE CENTRALIZER PER ANODE SHALL BE USED AND MOUNTED OVER THE COPPER RING AT THE ANODE CENTER

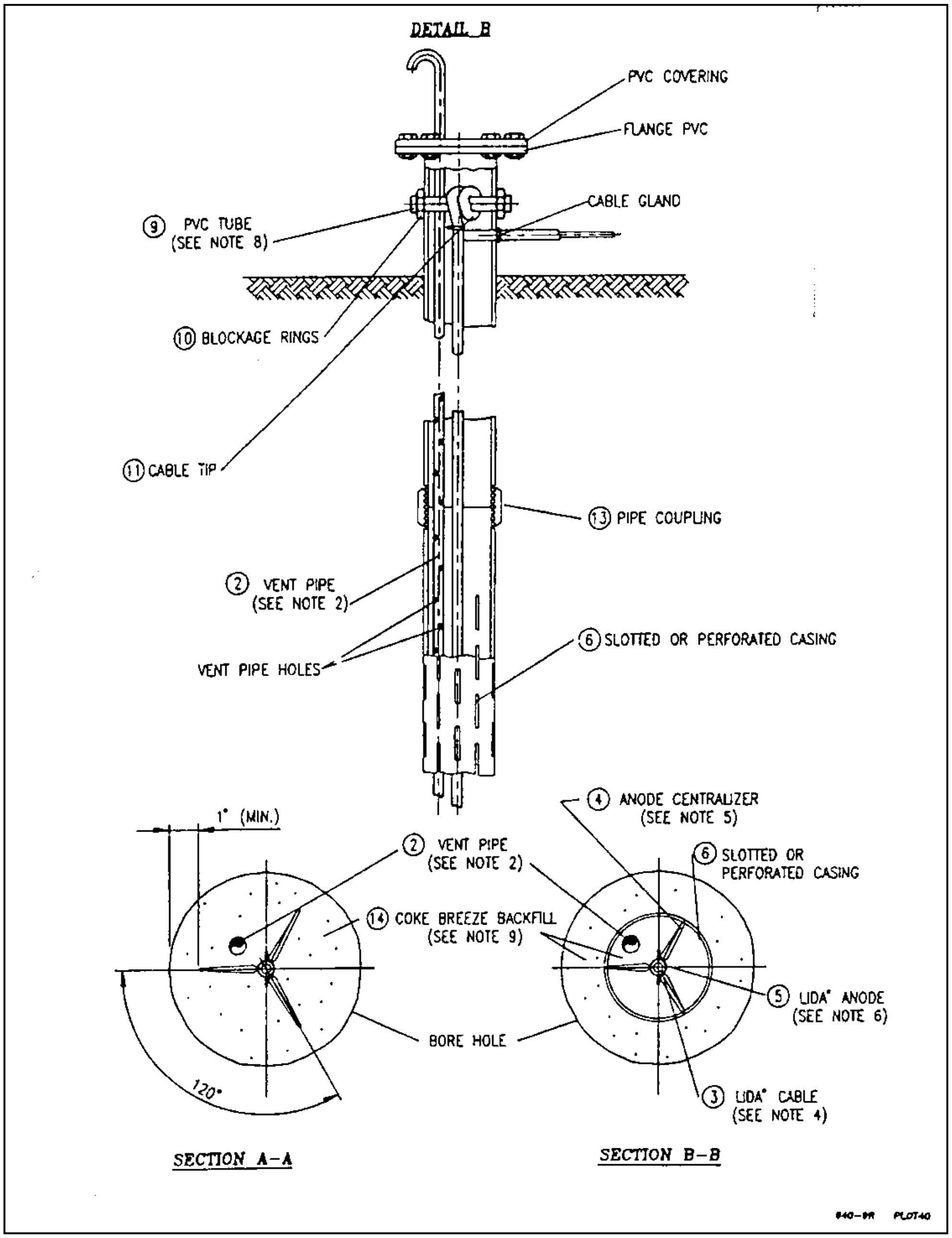
⑥ THE UDA ANODES ARE MIXED METAL OXIDES ACTIVATED TITANIUM TUBES

⑦ THE CASING SHALL BE PERFORATED WITH SLOTS OR HOLES THE HOLES SHALL BE DRILLED WITH 45DEG. ANGLE

⑧ A PVC TUBE WITH BOTH ENDS THREADED SHALL BE USED AS ANODE STRING SUPPORT

⑨ THE COKE BREEZE BACKFILL SHALL PREFERABLY BE FLUIDIZED WITH WATER TO FORM A SLURRY AND PUMPED INTO THE GROUNDBED HOLE FROM THE BOTTOM UP UTILIZING A SEPARATE LOADING PIPE

EXHIBIT B
(Page 2 of 2)



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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Thermite Weld Process**	Standard Number: **GS 1420.580**
Supersedes: 03/01/2010		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Proper personal protective equipment (PPE) shall be used during the thermite welding process, according to the standards within HSE Series 4200 “Safety - Personal Protective Equipment.” All other appropriate safety measures in the HSE Volume 4000 shall be followed, including the proper placement of a fire extinguisher.

The thermite weld process requires the equipment and materials of a:

a. thermite mold (furnace) appropriate for the application - traditional or new style with an electronic control unit (see Section 2 below),

b. thermite welding charge,

c. facility, and

d. test or anode lead wire.

2. THERMITE WELD PROCESS

There are basically two methods that can be used to complete the thermite weld process:

a. the traditional thermite mold (see Figure 1), or

b. the thermite mold with an electronic control unit (e.g., CADWELD® PLUS System, see Figures 2, 3, and 4).

Figure 1: Traditional Thermite Mold

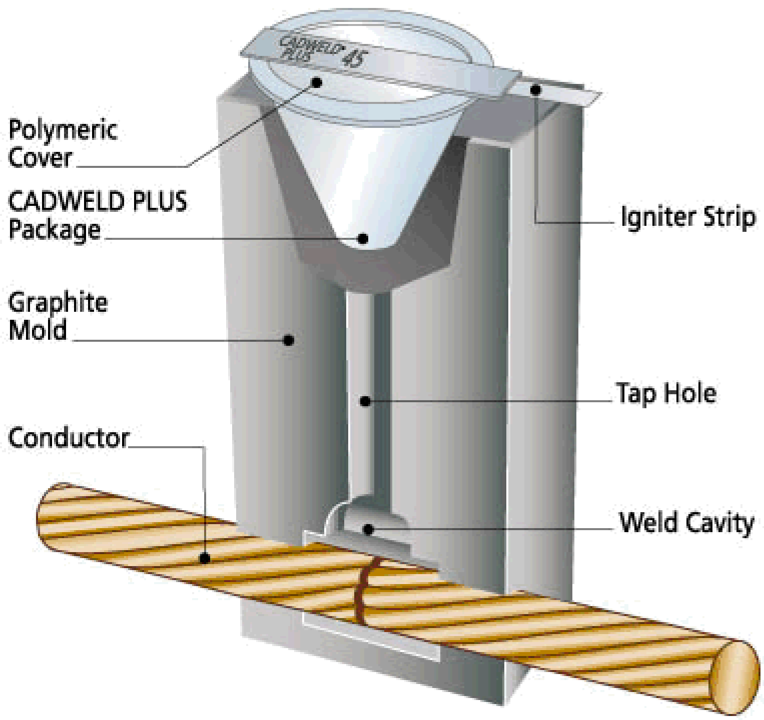

Figure 2: CADWELD® PLUS Mold

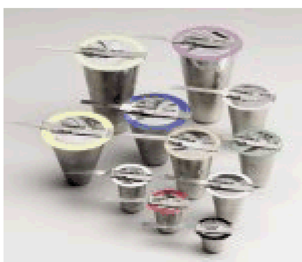

Figure 3: CADWELD® PLUS Welding Material

Figure 4: CADWELD® PLUS Control Unit

2.1 Preparation of Steel and Cast Iron Surfaces

1. Remove sufficient coating from pipe to expose an area large enough for the mold.
2. Pipe surface must be bright, clean and dry. Use file or grinder with a wire brush wheel to remove all mill scale, rust, grease, and dirt. Dry surface with a clean cloth. Cast iron surfaces having a pitch coating should be cleaned with a solvent.
3. Carefully examine the pipe for pitting. Do not make a thermite weld over a deep pit. Do not ignite a thermite weld if natural gas is detected in the excavation.
4. Thermite welds shall be a minimum distance of four (4) inches apart from adjacent thermite welds and six (6) inches apart from pipe welds.

2.2 Welding Procedure for Traditional Thermite Mold

1. Remove insulation from end of test lead or anode lead wire. Install a reinforcing sleeve on end of wire size AWG #8 or smaller. Conductor should protrude 1/8" beyond end of sleeve. For wire size larger than AWG #6 stranded, if a mold is not available that can handle the larger size, separate strands into two or more groups and weld each group to the pipe separately at a minimum distance of four (4) inches apart.

2. Select the correct welder to fit the pipe size and conductor. For three (3) inch and smaller pipe, a curved mold should be used. For four (4) inch and larger pipe and for flat surfaces, a flat mold should be used.

3. Clean any slag from mold. Examine the mold to ensure that it is dry and has not deteriorated. Do not use a “burned out” or wet mold.

4. Insert steel disk in the concave position (i.e., downward like a bowl) in mold to retain powder.

5. Empty powder cartridge into crucible. Remove starting powder from bottom of cartridge and spread evenly over welding powder. Do not use a powder charge larger than 15 grams (cartridge #15) on steel pipelines. For thermite welds on cast iron, refer to manufacturer instructions; a different alloy powder is used for cast iron.

6. Place mold on the cleaned pipeline with the wire end centered under the mold. Make sure the wire is not wet. Wet wire can cause molten metal to blow-out of the mold.

7. Close cover and ignite powder with flint gun. Matches or cigarette lighters shall

not be used. If charge does not light, remove and replace with a fresh charge.

8. Remove welder and clean out any slag deposit.

9. Strike the finished thermite weld with a hammer to insure a good brazed connection.

10. Remove all slag from the weld area. Clean, prime, and coat the thermite weld and the bare exposed pipeline. See Section 2.3 below for additional coating guidance.

11. Leave adequate slack in wire at pipe surface (i.e., half-hitch connection) so there is minimum tension and wire movement at the weld connection during the backfill operation.

NOTE: When using a thermite mold with electronic control unit, such as the CADWELD® PLUS System, use according to the manufacturer's instructions.

2.3 Coating Procedure

The thermite connection area is to be coated according to GS 1420.035 "Coating Repair Methods for Mill Applied Coatings" or as directed by local corrosion personnel.

1. Clean the metal surface and any part of the mill applied coating which is to be covered. Allow the weld to cool before applying primer or coating products.

2. Coating shall be applied according to manufacturer specifications. The coating must be thoroughly sealed where the wire exits the coating application. See Figure 5 below.

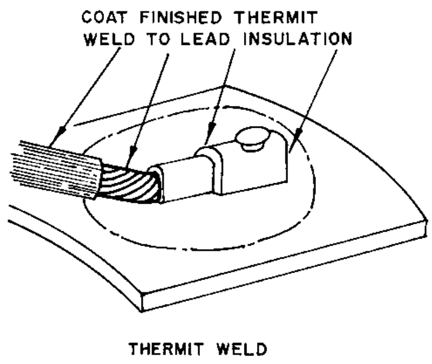

Figure 5: Coating of Thermite Weld Connection

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Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Evaluation of New Cathodic Protection Systems	Standard Number: GS 1430.010
Supersedes: 04/01/2009		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

A new cathodic protection system installed on a new pipeline shall be evaluated, fully functional, and providing an acceptable level of protection (see GS 1420.020 "Criteria for Cathodic Protection) over its entirety within one year after the in-service date of the pipeline.

A new cathodic protection system installed on an existing pipeline shall be evaluated, fully functional, and providing an acceptable level of protection within one year after it has been installed.

Known or suspected stray current areas shall be investigated and evaluated as quickly as possible.

Once a cathodic protection system has been evaluated and the criterion for cathodic protection has been met, the criterion should not be changed for subsequent monitoring without a re-evaluation and appropriate documentation to support the change.

2. EVALUATION OF A GALVANIC (SACRIFICIAL) ANODE SYSTEM

The following tests shall be conducted to ensure that a newly installed galvanic anode system is fully functional and providing an acceptable level of protection.

a. Test to ensure that electrical isolation is adequate. Refer to GS 1430.250 "Verifying Electrical Continuity and Isolation" for guidance.

b. Test to ensure that electrical continuity is adequate. Refer to GS 1430.250 "Verifying Electrical Continuity and Isolation" for guidance.

c. Take measurements of operating currents and voltages of anodes connected through existing test stations. Refer to GS 1430.220 "Current Flow Measurements" and/or GS 1430.110 "Pipe to Soil Potential Measurements" for guidance.

d. Test for interference from other structures under rectifier protection. Refer to GS 1420.100 "Corrosion Control Design – Stray Current Control" for guidance.

e. Test for stray currents or other unusual corrosion conditions. Refer to GS 1420.100

"Corrosion Control Design – Stray Current Control" for guidance.

f. Test to ensure that cathodic protection meets one of the criteria required in GS 1420.020 "Criteria for Cathodic Protection." Refer to GS 1430.110 "Pipe to Soil Potential Measurements" for guidance.

g. Based on tests above, establish designated half-cell placement for future monitoring of system low points. Update designated test point facilities in the Company's work management system, or equivalent.

3. EVALUATION OF AN IMPRESSED CURRENT SYSTEM

Native pipe-to-soil close interval survey potential measurements should be taken prior to activation of the cathodic protection system and filed for future reference. Refer to GS 1430.120 "Close Interval Survey."

No impressed current system may be put into operation, except for testing purposes, until it is determined that all electrical shorts and interference problems in the piping system have been located and corrected.

The local underground corrosion coordinating committee should be notified of rectifier operation in accordance with the committee's by-laws. In areas where there is no committee, the appropriate representatives of nearby utilities and other structures that could be affected by the operation of the rectifier should be notified.

The following tests shall be conducted to ensure that a newly installed impressed current system is fully functional and providing an acceptable level of protection. The following tests shall be conducted after the system has enough time to fully polarize.

a. Check the cable connections at the rectifier to ensure that the positive connection goes to the ground bed and the negative connection goes to the pipeline.

b. Test to ensure that electrical isolation is adequate. Refer to GS 1430.250 "Verifying Electrical Continuity and Isolation" for guidance.

c. Test to ensure that electrical continuity is adequate. Refer to GS 1430.250 "Verifying Electrical Continuity and Isolation" for guidance.

d. Interrupt current source(s) and take "on" and "instant off" pipe-to-soil close interval survey potential readings. The "off" cycle should be as brief as possible, but should be greater than 200 milliseconds. and the "on" cycle should be approximately twice as long as the "off" cycle

e. Test to detect interference currents from foreign structures. Refer to GS 1420.100 "Corrosion Control Design – Stray Current Control" for guidance.

f. Evaluate IR drops.

g. Test to ensure that cathodic protection meets one of the criteria required in GS 1420.020 “Criteria for Cathodic Protection.”

h. Based on results from above tests, establish designated half-cell placement for future monitoring of system low points. Update designated test point facilities in the Company’s work management system, or equivalent.

4. EVALUATION OF A STRAY CURRENT CONTROL DEVICE

The following tests shall be conducted to ensure that a newly installed stray current device is fully functional and providing an acceptable level of protection.

a. Test to ensure that the stray current has been mitigated or that there is no detrimental stray current. Refer to GS 1430.020 “External Corrosion Control Monitoring” for guidance on the tests required for interference inspections.

b. Test to ensure adequate electrical continuity. Refer to GS 1430.250 “Verifying Electrical Continuity and Isolation” for guidance.

c. All devices (refer to GS 1430.020 “External Corrosion Control Monitoring”) that have been installed to mitigate stray current shall be designated as test points in the Company’s work management system, or equivalent. Test to ensure that cathodic protection meets the criteria established in GS 1420.020 “Criteria for Cathodic Protection” for the cathodic protection system.

5. REMEDIAL ACTIONS

If deficiencies are found during the evaluation of cathodic protection systems or stray current devices, corrective action shall be taken promptly to reach adequate cathodic protection within one year after the in-service date of the pipeline.

6. RECORDS

Existing Company records shall be used to document tests and readings obtained during the evaluation process and should be filed for the life of the pipeline. Records shall be documented in the Company’s work management system and/or local cathodic protection system records (e.g., circuit pack).

Distribution Operations

Gas Standard

Effective Date: 01/01/2014	External Corrosion Control Monitoring	Standard Number: **GS 1430.020(KY)**
Supersedes: 12/31/2012		Page 1 of 5

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.465, 192.491, 192.709; KY 807 KAR 5:006 Section 26(3)

1. GENERAL

Galvanic (sacrificial) anode cathodic protection systems, impressed current cathodic protection systems, and stray current areas shall be monitored and inspected as prescribed below.

The operation and maintenance of cathodic protection systems must be carried out by or under the guidance of corrosion personnel who are qualified in pipeline corrosion control methods, as defined in GS 1400.010 "Corrosion Control – General."

2. ANNUAL MONITORING OF CATHODIC PROTECTION SYSTEMS

Cathodic protection systems shall be monitored at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine if the cathodic protection system is functioning and meeting the selected cathodic protection criterion.

2.1 Short Sections of Cathodically Protected Pipelines

If annual monitoring is impractical for short sections of cathodically protected mains or transmission lines not in excess of 100 feet or separately protected service lines, they may be monitored on a sampling basis. At least 10% of these cathodically protected pipelines distributed over the entire system shall be monitored each year, with a different 10% checked each subsequent year, so the entire system is monitored in each 10-year period. This 10-year period monitoring is recommended where annual monitoring of these short sections or service lines becomes impractical due to quantity.

2.2 Electrically Isolated Metallic Fittings in Plastic Pipelines

The installation of electrically isolated metallic fittings within plastic pipelines should be avoided when possible. However, when electrically isolated metallic fittings are installed in a plastic pipeline, the metallic fitting shall be monitored for cathodic protection, unless the isolated metallic component can be bonded to an adjacent cathodic protection system. Refer to GS 1400.010 "Corrosion Control – General." Electrically isolated metallic fittings that are cathodically protected separately are considered short sections of cathodically protected pipelines and may be monitored according to Section 2.1 above.

3. MONITORING METHOD

Monitoring shall consist of taking a minimum of one pipe-to-soil potential reading over the protected pipeline from each designated test point. A copper-copper sulfate half-cell filled with a saturated copper sulfate solution shall be used as the reference electrode. Refer to GS 1430.110 “Pipe-to-Soil Potential Measurements.”

A pipe-to-soil reading shall not be taken directly over or adjacent to an anode, with the exception of when taking a pipe-to-soil reading over an isolated steel service riser or isolated metallic fitting in a plastic pipeline that is cathodically protected with an anode. Refer to GS 1430.110 “Pipe-to-Soil Potential Measurements” for additional guidance.

4. CONSIDERATION OF IR DROP

When taking pipe-to-soil potential readings, the effect of IR drop (errors in observed voltage measurements due to unintended resistances) must be considered when using the -850 mV “On” Potential with IR Drop Considered criterion (most commonly used criterion).

NOTE: The effect of IR drop is already considered when using either the 100 mV Polarization Shift or the -850 mV Polarized Potential criterion. Refer to GS 1420.020 “Criteria for Cathodic Protection” for guidance on IR drop consideration for any of the other not so commonly used criteria.

4.1 General Consideration of IR Drop

The effect of IR drop is minimized through the existing guidelines for taking pipe-to-soil potential measurements. Refer to GS 1430.110 “Pipe to Soil Potential Measurements” for more information.

In addition, review of the historical performance of the cathodic protection system, including physical evidence of corrosion reported according to GS 1410.010 “Metallic Pipeline Exposures,” may require additional measures to consider IR drop. Refer to GS 1460.030 “Investigating Leaks on Coated Pipeline” for additional guidance.

4.2 Additional Considerations for Impressed Current Systems

For impressed current systems with rectifier power source(s), “instant-off” pipe-to-soil potential measurements shall be taken while the current sources interrupters are synchronized. This is essentially using the -850 mV Polarized Potential criterion.

Instant-off readings may not be practical for impressed current systems that do not use rectifiers (e.g., solar power) or for hybrid systems with some level of magnesium anode protection and supplemented by impressed current.

For transmission lines (e.g., TC line) protected by rectified impressed current systems, all rectifiers that are part of the cathodic protection circuit (including foreign rectifiers and bonds) shall be synchronized with interrupters.

For distribution systems protected by rectified impressed current systems, experimental verification may be used to determine which rectifiers directly impact the locations to be monitored and therefore must be synchronized with interrupters (including foreign rectifiers and bonds). This determination must be reevaluated if conditions impacting the cathodic protection system change (e.g, metallic pipeline extensions or abandonments, addition or removal of current sources, changes in current output).

5. BI-MONTHLY INSPECTIONS OF IMPRESSED CURRENT SYSTEMS

In addition to the annual monitoring requirements stated above, bi-monthly inspection requirements for impressed current systems are listed below.

a. The impressed current power source (e.g., rectifier) shall be inspected to ensure that the system is operating properly 6 times each calendar year, but with intervals not exceeding 2½ months.

b. The inspection shall consist of measuring the current (e.g., amperage) and voltage output of the impressed current power source.

6. INTERFERENCE INSPECTIONS

Each stray current mitigation device (e.g., reverse current switch, diode, interference bond, magnesium anode drain) whose failure would jeopardize structure protection (i.e., critical) shall be inspected 6 times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating properly.

Stray current mitigation methods whose failure would <u>not</u> jeopardize structure protection shall be monitored at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine whether the stray current mitigation method is functioning satisfactorily and Company pipeline conditions have not changed.

Stray current mitigation methods shall be considered critical if the effect without the device is detrimental to the Company pipeline and falls below cathodic protection criteria in GS 1420.020 “Cathodic Protection Criteria.” In stray current areas, it is critical to consider IR drop (see Section 3 above).

Inspection requirements for stray current mitigation methods shall consist of taking at least one pipe-to-soil potential measurement on the Company structure sufficient to verify that cathodic protection is maintained (i.e., an adverse condition does not exist) and a current measurement. In addition, for reverse current switches, the inspection shall include a test to ensure that the blocking device is operative.

A best practice to complete for troubleshooting purposes or on an annual basis includes taking pipe-to-soil potential readings of the Company pipeline(s) and foreign structure(s) with the bond connected and disconnected, with the stray current power source on.

Another best practice is to monitor bonds to mine or railway substations on an annual basis during a 24 hour period of time using a recording device.

7. EXCESSIVE PIPE-TO-SOIL POTENTIALS ON IMPRESSED CURRENT SYSTEMS

For impressed current systems, “on” pipe-to-soil potential readings that are more negative than -2.0 V outside of the voltage gradient of the impressed current ground bed indicate excessive pipe-to-soil potentials, which may cause coating damage or hydrogen damage to the steel.

8. REMEDIATION

Unsatisfactory readings (i.e., readings that do not meet the criterion used to evaluate the cathodic protection system described in GS 1420.020 “Cathodic Protection Criteria” or readings indicating excessive pipe-to-soil potentials) found during the inspection and/or monitoring processes are considered cathodic protection system deficiencies and shall be promptly corrected. Remediation of the defective system shall involve acceptable corrosion troubleshooting techniques (refer to GS 1430.410 “Cathodic Protection Troubleshooting Methods” for additional guidance) and may include a re-evaluation to ensure that all footage assigned to a test station or circuit meets its established cathodic protection criterion.

Deficiencies found during the annual monitoring program and/or the bi-monthly inspection program shall be corrected prior to the next monitoring or inspection cycle, except as follows. If remedial action cannot be completed prior to the next monitoring or inspection cycle, the actions taken to correct the deficiency and the expected time-frame to complete the repair shall be documented by local corrosion personnel and approved by local corrosion leadership.

For short sections of cathodically protected mains or transmission lines, or separately protected service lines or metallic fittings, that are monitored on a sampling basis (e.g., once every ten years), deficiencies should be corrected within 15 months of discovery.

Deficiencies found outside of the monitoring and inspection programs shall be corrected within 12 months of discovery.

Unless protected together, where pipe-to-soil and adjacent casing-to-soil potential measurements are essentially the same, further evaluation and testing shall be initiated.

Obvious maintenance work of the test station, such as cleaning and tightening loose connections, replacing the lid, etc., should be performed during the monitoring/inspection process. However, if significant work needs to be performed, instructions shall be noted for the creation of a future work order.

If the pipe-to-soil reading cannot be taken due to the test station being damaged, lost, or inaccessible due to weather conditions, and an alternative test point was not selected, the test point shall be treated as unsatisfactory, and instructions shall be noted for the creating of a future work order for repair or replacement of the test station. The work to repair or replace the test station should be completed in a reasonable amount of time to allow for an inspection and possible remediation/correction to occur within 15 months from the date on which the test station was monitored during the previous year, but no later than the next monitoring cycle.

Remedial work should be designed for a life of at least 20 years, if practical.

9. RECORDS

Document each monitoring, inspection, and remedial action required by this standard. The date and time of the monitoring or inspection shall be recorded in the electronic WMS Job Order execution remarks field. This information shall be retained in the Company's work management system or equivalent.

Records of cathodic protection system annual monitoring shall be retained for as long as the pipeline remains in service.

Records of impressed current and interference inspections shall be retained for at least 5 years, plus the current year. For troubleshooting purposes, a best practice is to retain this information for the life of the cathodic protection system.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Active Corrosion**	Standard Number: **GS 1430.030**
Supersedes: 08/01/2010		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.465

1. GENERAL

Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety. An area of active corrosion exists only when the following two conditions have been met:

a. the severity and rate of corrosion is significant; and

b. in the judgment of the Company, the physical location of the corroding facility could reasonably create a condition detrimental to public safety.

Unprotected pipelines shall be reevaluated at least once every three (3) years at intervals not exceeding 39 months to determine if areas of active corrosion exist.

For the purpose of this standard, an **unprotected pipeline** means a metallic pipeline (other than cast iron and ductile iron) that is not cathodically protected in accordance with GS 1420.020 "Criteria for Cathodic Protection."

2. RESPONSIBILITY

The responsibility of identifying and determining areas of active corrosion is shared by three functional groups: Field Operations, Engineering, and Corrosion (i.e., the Company). The Company should review corrosion indicators to evaluate its unprotected pipelines for areas of active corrosion at least once each calendar year.

3. DETERMINING AREAS OF ACTIVE CORROSION

3.1 Unprotected Transmission Lines

The Company will cathodically protect all transmission lines.

3.2 Unprotected Distribution Lines

Typically, an electrical survey is impractical for unprotected distribution lines (e.g., pavement, utility congestion, lack of electrical continuity), and therefore areas of active corrosion shall be determined by a review and analysis of the following corrosion indicators:

a. leak repair and inspection records (e.g., open leaks, repaired corrosion leaks, Optimain DS®, work management system reports),

b. corrosion monitoring and testing records,

c. metallic pipeline exposure records, and

d. existing records or knowledge of the pipeline environment (e.g., soil resistivity, soil moisture, soil contaminants).

3.3 Assessing the Effect on Public Safety

In reference to the definition of “active corrosion” stated above in Section 1, the determination that active corrosion exists depends on an assessment of whether conditions are such that continuing corrosion could result in a detriment to public safety. The following factors should be considered in assessing the effect on public safety:

a. leak frequency,

b. pressure,

c. location of piping,

d. location of dwellings and other structures, and

e. gas venting and migration characteristics of the area.

Continuing corrosion should be considered as active corrosion if it is determined that operating and maintenance actions will not control the corrosion condition to the extent that prevents it from becoming detrimental to public safety.

Personnel qualified by training or experience shall determine if the situation “could result in a condition that is detrimental to public safety.”

4. REMEDIATION

Pipeline sections that are determined to be areas of active corrosion shall either be cathodically protected, replaced, or abandoned. Remedial action shall be scheduled and completed promptly. However, if remedial action cannot be completed within 15 months (e.g., permit issues, material lead time), the actions taken and the expected timeframe for completion shall be documented.

5. AREAS OF CORROSION CONSIDERED TO BE “NOT ACTIVE”

If the evaluation of a corrosion area concludes that the corrosion area is “not active,” prompt remediation is not required.

For areas of local protection provided by coating and galvanic anodes at individual locations of "not active" corrosion, the corrosion protection levels are not subject to the monitoring requirements.

These areas are included in the Company review meeting that occurs at least once each calendar year (refer to Section 2 above).

6. RECORDS

Areas of active corrosion shall be documented on Form 1430.030-1 "Active Corrosion Log" (see Exhibit A), or equivalent. If no areas of active corrosion are found during the review, indicate this information on Form 1430.030-1 "Active Corrosion Log," or equivalent.

Form 1430.030-1 "Active Corrosion Log" shall be retained for the life of the pipeline or for at least ten years after the in-service date of the remedial action if the pipeline is replaced and/or abandoned.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Active Corrosion	Standard Number: GS 1430.030
Supersedes: 08/01/2010		Page 4 of 4

EXHIBIT A

ACTIVE CORROSION LOG

Company		Operations Center (Name and/or Number)							
Local Area Name or TCC	Town	Location (street or intersection)	Between Streets	Map Number or GIS Grid	Footage	Date Determined to be Active Corrosion	Remedial Action and work order number	Comments	Date Remedial Action Completed

FORM GS 1430.030-1
(01/2010)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Pipe to Soil Potential Measurements	Standard Number: **GS 1430.110**
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.465, 192.491

1. GENERAL

This standard provides guidance for performing pipe-to-soil potential measurements on buried or submerged pipelines. A pipe-to-soil potential measurement is one of the standard techniques used to verify cathodic protection based on the criteria defined in GS 1420.020 “Criteria for Cathodic Protection.”

It is the responsibility of the front line leader/supervisor to ensure all personnel performing pipe-to-soil potential measurements are Operator Qualified (OQ).

2. EQUIPMENT

The equipment needed to perform pipe-to-soil measurements to verify that cathodic protection exists on underground piping systems consists of the following:

a. a copper-copper sulfate half cell,

b. a high impedance voltmeter (minimum 10 megohms input impedance; see note below), and

c. insulated test leads.

NOTE: A high impedance voltmeter is critical for consideration of the effect of IR drop on the pipe-to-soil potential measurement. It ensures that the pipe-to-soil potential reading on the voltmeter is a high percentage of the actual pipe-to-soil potential measurement. It often renders the effect of IR drop to a negligible level.

Before every field use as an operational check, make sure that the battery and test leads of the voltmeter are working properly. Also, visually inspect the copper-copper sulfate half cell to assure that the solution is at an adequate level. The windows of the reference electrode should be covered with an opaque material, such as electrical tape, to eliminate a photo-sensitive measurement error.

2.1 Calibration Check and Inspection of Equipment

The following equipment evaluation shall be completed prior to the start of the annual monitoring program, at least twice per year (not to exceed 7 ½ months), and anytime faulty equipment is suspected.

a. Check the battery and the continuity of the test leads for proper working condition.

b. Perform a calibration check on the voltmeter by comparing against a known calibrated voltage source. The comparison must be within the range of the manufacturer's accuracy specifications; otherwise, the voltmeter shall not be used unless it is recalibrated.

c. Compare the half cell to a standard copper-copper sulfate reference electrode (i.e., CSE). A standard CSE is one that has not been used other than for calibration. If the comparison indicates a difference between the readings greater than 5 mV, then inspect the copper rods for corrosion by-products and clean, if necessary. Replace the solution if contaminants are evident.

NOTE: Solution shall either be copper sulfate liquid or de-ionized water. It is recommended to also use copper sulfate crystals for better saturation of solution and copper sulfate anti-freeze solution to prevent damage and inaccurate readings during cold months. With new replacement electrodes, allow the solution to saturate the porous tip and to stabilize for approximately 24 hours before using.

3. PERFORMING PIPE TO SOIL POTENTIAL MEASUREMENTS

Use the following guidelines when performing pipe-to-soil potential measurements.

1. For consistency, the negative lead should be connected to the reference half cell and the positive lead should be connected to the structure. The potential reading should typically be a negative reading. If the potential reading is positive, this may indicate a critical situation (e.g., stray current).

2. To reduce IR drop in the circuit, place the half-cell directly over or as close as practical to the pipeline. Pipe-to-soil potential readings are not to be taken over or adjacent to an anode, with the exception of taking a pipe-to-soil reading over an isolated steel service riser or metallic or isolated metallic fitting in a plastic pipeline that is cathodically protected with an anode. Reading within the anode gradient will include the voltage drop in the earth caused by current discharge from the anode. Therefore, the reading obtained will not reflect the correct potential between pipe and earth. If an anode is at the test station (with the exception of an isolated steel service riser or isolated metallic fitting in a plastic pipeline), disconnect the anode and/or take a reading at least 25 feet from the

test station and subsequent readings at least 25 feet from the previous reading and anode.

3. The half-cell must be in good contact with the soil. The removal of sod and gravel may be required to obtain good contact with the soil. For extremely dry conditions, the soil in the immediate area where the half-cell will contact the soil may need to be saturated with water to reduce contact resistance.

4. No readings shall be taken with the copper-copper sulfate half cell placed onto a high resistance surface, such as black top or a tar cover surface, so provisions such as drilled hole(s) or a soil access box may be needed.

5. Concrete surfaces shall be wet down to help reduce high IR drop potential readings.

6. The operator shall not make contact with the bare test lead connections or allow the bare test lead connections to come in contact with the ground or any other structure with a DC potential.

4. RECORDS

Records for calibration of equipment shall be maintained in the Company work management system, or equivalent, for at least 5 years plus the current year. Calibration records must include identification of equipment (e.g., serial number, calibration sticker). A calibration sticker may be used for recording calibration dates on specific equipment in place of recording a serial number in the Company's work management system.

Refer to GS 1430.020 "External Corrosion Control Monitoring" for the retention requirements of pipe-to-soil potential measurements.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Close Interval Survey	Standard Number: GS 1430.120
Supersedes: 05/01/2010		Page 1 of 11

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

A Close Interval Survey (CIS) measures pipe-to-soil potentials at close intervals along the pipeline. An Interrupted CIS measures the pipe's cathodic polarization by reducing IR error at specified intervals. The measurements from these surveys can then be integrated with other measured assessment tools to determine locations of anomalies that may result in possible corrosion.

For transmission lines, the CIS will be evaluated and scored to the level of severity based on IMP-6-14 "External Corrosion Direct Assessment Plan," Exhibit D.

2. INTERVALS

Typical CIS intervals (i.e., reference electrode spacing) are listed in Table 1 below.

Table 1

Project Type	Reference Electrode Spacing
New Steel Distribution Main	10 – 20 feet
Transmission Lines	2 – 5 feet
General Troubleshooting	Start with 10 - 20 feet; Adjust as needed
Investigating Leak on Coated Pipeline	5 feet (maximum)
Interference Testing	Start with 10 - 20 feet; Adjust as needed

Take additional measurements, as necessary, during the survey to verify conductive and isolation paths.

3. GENERAL PROCESS

The following steps should be taken to obtain accurate CIS measurements. Some of the steps below are applicable only to CIS for Pipeline Integrity purposes.

3.1 Locate the Pipeline

The pipeline shall be located by direct conductive method. The equipment should have the capability of obtaining depth readings, with peak and null indicators.

3.2 Field Marking

The pipeline shall be marked at intervals of 10 to100 feet spacing, depending on pipeline deflection and/or topography. The marking material (e.g., paint mark, flag) shall be visible from the previous marker while the survey is conducted.

When completing a CIS for Pipeline Integrity the spacing will also depend on the data integration process (see Section 5 below).

3.3 Global Positioning Satellite (GPS)

Typically, GPS coordinates will be obtained for a CIS completed for Pipeline Integrity purposes.

GPS equipment used for the purpose of surveying must have sub-meter accuracy. The GPS unit must be given adequate time for logging depending on the satellite power reception indicator. Batteries shall be checked daily before the equipment is used.

All post-processing should be completed within two weeks of survey.

3.3.1 Locations

GPS points are to be taken at intervals according to Section 2 of this procedure, within the boundary of the survey (e.g., HCA) at the beginning and ending station locations, significant geographical locations (e.g., top of creek banks, ditch bottom, edges of pavement), locations where different pipe properties (e.g., diameter, wall thickness, pipe grade) meet, wire breaks, foreign crossings, and proximity of AC or other current sources, if practical.

Comments shall be documented on each point to indicate geographical locations, address, pole numbers, or any other land marks to identify alignment.

3.4 Interruption

For pipelines protected by rectified impressed current systems, all rectifiers directly impacting the cathodic protection circuit (including foreign rectifiers and bonds) shall be interrupted with synchronization. Refer to requirements in GS 1430.020 "External Corrosion Control Monitoring."

The interrupter unit maximum input voltage shall not be exceeded. Determine the impressed current system's DC output voltage before making the connection to the interrupter.

Operate the interrupter unit according to manufacturer's instructions. Batteries shall be checked or replaced daily before the equipment is used.

Before installing the interrupter, rubber mats shall be placed to create a high resistance barrier between the user and the ground, and then power shall be de-energized to rectifier unit.

The unit shall be secured and located to prevent accidental or intentional tampering (e.g., a weather proof seal container locked).

If unit cannot be locked closed with the interrupter, then high voltage warning signs shall be posted to prevent accidental contact by pedestrians.

3.4.1 Frequency of "ON" and "OFF" Cycles

The frequency shall be set for the "ON" cycle to be 2-3 times as long as the "OFF" cycle to prevent polarization decay.

The spike typically lasts a few 100 milliseconds; therefore the "OFF cycle" should be measured 200 to 300 milliseconds after interruption.

3.5 Metallic IR Drop Consideration

Metallic IR drop shall be measured during the survey run when evaluating new steel pipeline, assessing transmission lines, or investigating leaks on coated pipeline. This will ensure that external resistances (i.e., insulator, high resistance coupling) within the pipeline being surveyed are known.

Direct metal-to-metal measurement of the IR drop can be accomplished by one of the following methods.

a. The metallic IR drop may be measured directly by connecting one lead of the meter to the near test station and the other to the survey wire attached to the previous test station.

b. The metallic IR drop may also be measured by the difference between the the fixed half cell test.

NOTE: If the comparison of the two potential readings indicates greater than 100 mV difference, then the further investigation is needed for possible high resistance coupling or insulation.

Metallic IR drop should be measured when applicable for both the “on” and “off” cycles.

Potentials shall be measured at the start of every survey run and at every contact point during the survey run and at the end of the survey run.

If the metallic IR drop indicates significant current in the pipe in the “off” cycle, an attempt should be made, when practical, to locate, determine the source of, and interrupt the influencing current. If significant errors are observed, the survey may be discontinued until the source of the error can be determined. Previously collected data should be evaluated for acceptable IR drop error. Errors that cannot be corrected shall be noted in the CIS data.

3.6 Additional IR Drop Considerations

High resistance coating on the wire shall be removed from hip pack wire to prevent a high resistance contact.

Refer to GS 1430.110 “Pipe to Soil Potential Measurements” for additional guidance on minimizing IR drop.

3.7 Data Logging

It is recommended to use a data logger for long surveys, and a data logger is required for CIS performed for Pipeline Integrity purposes. The data logger should be set at the highest setting of input impedance. Set up the data logger to identify locations of the survey being conducted. A recommended practice is to name the file (e.g., HCA survey location). The readings should be documented to the 1/1000 of a volt (i.e., -1.325 v).

All data logging equipment used for the CIS purpose shall have accurate voltmeter capabilities with a high input impedance of a minimum of 10 megohms. The “on” and “off” cycle frequency shall be set up the same as the synchronized interrupter. The 0.850-VCSE alarm signal should be set, if the -0.850 V criterion for cathodic protection is used.

The reference cells shall be copper-copper sulfate reference electrodes with copper sulfate solution. A best practice is to use an approved copper sulfate antifreeze solution.

Data shall be collected at intervals according to Section 2 of this procedure.

3.7.1 Calibration of Reference Electrode Cells

All reference electrode cells shall be calibrated to a virgin reference electrode cell of the same type by one of the three methods listed below. Calibration shall be completed daily before beginning the survey.

1. Contact the points of the reference electrode cells together and measure the voltage difference.
2. Place both reference electrode cells in the same solution or electrolyte as close as possible and measure the voltage difference.
3. Place each reference electrode into the same location and measure the voltage potential of the metal structure at the same contact point; record the potential readings between the two reference electrode cells.

All reference electrodes must be within 5 mV of the virgin reference electrode cell. If any deviation of readings on existing reference electrode cells indicated above 5 mV, then the copper-copper sulfate half cells must be cleaned and new saturated solution added, then recheck and repeat the process. If there is no change, then new replacement reference electrodes must be used.

NOTE: With new replacement electrodes, allow the solution to saturate the porous tip and to stabilize for approximately 24 hours before using.

The windows of the reference electrodes should be covered with an opaque material, such as electrical tape, to eliminate a photo-sensitive measurement error.

Calibration and verification shall be documented.

3.7.2 Wire Connections

All wire connections shall reflect a negative voltage potential, with the negative lead connected to the reference electrode cell and the positive lead connected to the test wire attached to the pipeline.

The recommended wire is a minimum 30 gauge insulated copper wire with a hip pack assembly.

If a wire connection obtains a break in the conductive path, reconnect to the nearest test point and continue from the point of loss of potential. The breakage should be documented, noting the time of the breakage, station number, and GPS location.

If a wire connection break occurs at the existing test point, attempt to re-connect survey wire.

On a daily basis prior to the survey, verify the wire connection by connecting the data logger directly to the pipeline bypassing the hip pack assembly, then re-connect the hip pack assembly and compare the potential readings. The readings shall not be more than 1 mV difference with the copper-copper sulfate half cell.

3.7.3 Calibration of Data Logger

The data logger calibration and verification shall be completed by one of the methods identified below.

a. Compare reading with a high input resistance multi-meter by connecting to fixed half cell.

b. Measure voltage against a known voltage source (e.g., fully charged battery).

If any deviation is obtained from the data logger readings, then the unit shall be calibrated based on the reading difference and re-tested for accuracy.

If the data logger cannot be calibrated based on the difference, then the unit shall be sent to the manufacturer for repairs and/or calibration.

The unit’s internal voltage level shall be checked on a daily basis before use; it shall be at least a 70% level of charge.

Calibration and verification shall be documented. Calibration and verification documents relating to the Company’s Pipeline Integrity Program shall be placed into the External Corrosion Direct Assessment (ECDA) filing or data base system.

4. SPECIAL SITUATIONS

4.1 Required Offsets

Conditions along the pipeline may make measurements directly over the pipeline impractical. In such cases, potentials may be measured offset to the center line of the pipeline.

Ensure there are no intervening structures (e.g., other underground facilities between the offset measurement location and the pipeline being surveyed) when offset measurements are obtained.

The instant-off potentials are representative of the level of protection of the pipeline; however, resolution is reduced, comparable to increasing the depth of cover.

See Section 7.1 below for documentation required with offset measurements.

4.2 Encroachments

Pipeline and/or easement encroachments shall be reported to the local field operations leader/supervisor.

4.3 River Crossing

When surveying transmission lines, river crossings shall be considered in the pre-assessment stage for areas that are not applicable for ECDA.

Areas of the river crossing that can be ECDA will be done by a weighted copper-copper sulfate electrode string across the river laying onto the river bed for potential readings. If a river crossing cannot be adequately tested using ECDA techniques, then another assessment method must be used (e.g., ILI, pressure test, or guided wave).

4.4 Pavement (Asphalt/Blacktop)

The spacing of measurements should be 5 to 10 feet.

Drill holes in pavement until soil is penetrated. Drill holes shall be made large enough in diameter to allow the electrode to make contact with the soil. Water or soapy water shall be added to allow low resistance contact for accurate potential readings.

5. DATA INTEGRATION

Readings that are not logged onto the data logger shall be documented on another recording device for further data analysis. For Pipeline Integrity purposes, information that is obtained from the survey shall be entered into a database or onto a spreadsheet for further anomaly identification and to integrate with all other tool data collection.

5.1 Anomalies

Anomaly identification for Pipeline Integrity purposes and scoring will be done according to the guidelines in IMP-6-14, Exhibit D.

6. SAFETY

Follow existing Company safety procedures for Personal Protective Equipment (PPE) and traffic control requirements.

6.1 Shock Hazards/AC currents

All wire connections shall be insulated in high voltage AC corridors. The operator could be exposed to hazardous voltages due to the electromagnetic (inductive) coupling between the power lines(s) and the testing conductor.

Avoid connecting the unit to a utility grounding electrode. The operator may receive an electrical shock if AC fault currents are being discharged onto the grounding system.

Avoid using equipment during electrical storms or severe weather conditions. The operator may receive an electrical shock by surrounding grounding devices or by a lightning strike.

The structure shall be checked for AC current by an AC voltage check with a multimeter and copper-copper sulfate electrode. For safety reasons, ensure that the half cell is in contact with the ground before the connection is made to the test station or structure.

a. If readings indicate AC voltage greater than 15 V, then follow up investigation is needed for possible AC mitigation.

b. If any AC voltage reading is obtained, perform an AC current density calculation (refer to GS 1420.120 “Controlling AC Influence”) to determine if AC corrosion is an issue.

c. A current density greater than 100 A/m^2 indicates that corrosion can be expected. Mitigation shall be performed as a priority.

d. A current density of 20 to 100 A/m^2 indicates that corrosion may develop, and mitigation is needed.

e. A current density of less than 20 A/m^2 indicates that no corrosion expected. No further action is needed.

6.2 Impressed Current Systems

Impressed current systems shall be tested prior to physical contact for AC currents on the outer case.

7. RECORDS

CIS records for transmission lines shall be filed in the Company's Pipeline Integrity files and kept for the life of the pipeline. CIS records relating to distribution lines should be filed in local corrosion files and kept for reference for the life of the pipeline.

When using a data logger, document applicable survey information as prompted by the data logger. If a data logger is not used (i.e., on CIS for distribution pipelines), document applicable survey information according to Form GS 1430.120-1 "Close Interval Survey Data Sheet" (see Exhibit A).

7.1 Additional Documentation Required With Offset Measurements

If offset measurements must be used, record the following information in the descriptor mode of the data logger or on the comment section of Form GS 1430.120-1 "Close Interval Survey Data Sheet":

a. the location at which the potentials begin to be offset from the center line of the pipeline, the distance the measurement(s) were offset from the pipe's center line, and the location at which the potential measurements go back to the center line of the pipeline.

b. the direction of offset (left or right, with respect to an observer facing downstation), and

c. the reason for the offset.

EXHIBIT A
(1 of 2)

Close Interval Survey Data Sheet

Performed By: ________________________________ **Total Footage Surveyed:** _______________

Location of Survey: ________________ **Line Name / #** _________________ **Pipe Size** ___________

Half Cell Spacing: __________ **Interrupter: Seconds "ON"_______, Seconds "OFF"** _______

Station #	Pipe to Soil Potentials		Comments - Descriptions
	"ON"	"OFF"	

Page **1** of **2**

Form GS 1430.120-1
(12/2012)

EXHIBIT A
(2 of 2)

Close Interval Survey Data Sheet

Station #	Pipe to Soil Potentials		Comments - Descriptions
	"ON"	"OFF"	
0 + 00			

Page **2** of **2**

Form GS 1430.120-1
(12/2012)

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Surface Potential Survey**	Standard Number: **GS 1430.130**
Supersedes: 05/01/2010		Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The surface potential survey can be used to help identify appropriate tie-in locations on non-cathodically protected pipeline, troubleshooting (e.g., for stray current, possible shorts), or for consideration of mitigation of non-protected pipeline.

A surface potential survey is made entirely along the surface of the soil directly over the pipeline. No electrical connection to the pipeline is made. Surface potential readings are a measurement of potential difference between two (2) matched copper-copper sulfate half cells in contact with the earth. This type of survey is useful in locating suspected anodic areas of a pipeline. The results should closely parallel those obtained by a pipe-to-soil survey. The surface potential survey is a suitable tool for bare pipeline surveys made to locate suspected anodic areas, to determine possible tie-in points for replacement projects, and to locate leaks that are causing watering off problems. The use of this survey method is limited to points where the half cell can be positioned directly over the pipeline. Since no connection is made to the pipeline, other structures in close proximity may influence local earth gradients to the point that the readings may not be representative of the true potentials of the pipeline.

As with the pipe-to-soil survey, the pipeline should be electrically continuous, isolated from other structures and the position of any insulated joints should be known. The location of anodes installed during previous maintenance or mitigation activities should be known as they will appear as strongly anodic points. Surface potential surveys may be completed on pipelines that are not electrically continuous; however, additional attention is needed during the interpretation of the data since points of isolation may show up as an anodic area.

2. EQUIPMENT

Surface potential measurements are obtained using the following:

a. a high input resistance voltmeter,

b. two matched copper-copper sulfate half cells, and

c. approved test leads.

The half cells used for the survey must be selected, cleaned and calibrated so that the potential difference between them is negligible (no more than three (3) millivolts). As the survey progresses, the cells should be checked against each other occasionally as their potentials may change slightly during use. Several closely matched half cells should be available prior to the start of a survey.

3. TEST METHOD

The survey consists of making and recording successive measurements between two copper-copper sulfate half cells at specific intervals directly over the pipe. Normal spacing between the readings for a surface potential survey is 10 feet. This spacing is reduced to half (5 feet) or less at points of polarity change.

The front half cell is used as the polarity reference. If the front half cell is positive with respect to the rear half cell, the reading is considered as positive. If the front half cell is negative with respect to the rear half cell, the reading is considered as negative.

Because the voltage values between the reference electrodes are normally low, each reference electrode contact with the earth should be free of leaves, grass, rocks, and other debris.

As the survey proceeds, a change in the potential reading from a positive to a negative value is normally considered as an indication of an anodic area. As each anodic pipe section is identified (i.e. positive to negative readings), a determination on the limits of pipe replacement will be made considering overall pipe condition, past leakage history, and the location of the identified bare steel anodic pipe sections with respect to each other.

3.1 Taking Side-Drain Potentials

The severity and extent of an anodic condition may be further determined by measuring side-drain potentials. These tests are generally made on both sides of the pipe to verify that current is leaving the line, and that the current is not leaving the pipeline via a galvanic anode.

The front half cell is again used as the polarity reference. The back half cell is placed perpendicularly away from the pipeline at a distance approximately equal to the depth of the pipeline. If the reading is positive, this indicates that current is flowing away from the pipeline. Enough readings should then be taken to define the area.

3.2 Interpreting Side-Drain Potentials

The presence of a galvanic anode connected to the pipe affects surface potential gradient measurements and generally appears as an anodic condition. Close observation of measured values quite often suggests the presence of galvanic anodes. As an anode is approached, its presence is usually indicated by earth gradients that are somewhat higher than normal for the area being surveyed. The side-drain measurements may provide higher measured values on the side of the pipe on which the anode is buried and lower values on the side of the pipe opposite the anode.

Service taps, side connections, other components of the pipe (e.g., mechanical couplings or screw collars with a higher metallic resistance than the pipe), or other close buried metallic structures may provide measured values that appear as an anodic condition. The side-drain measurements are useful to evaluate the data.

Any situation not determined to be caused by some other factor is typically considered as an anodic condition.

4. RECORDS

The electrical survey data collected for a surface potential survey should be recorded on CDC Form C 1282-9 “Surface Potential Survey” (Exhibit A), a data logger, or equivalent documentation.

Surface potential surveys should be kept for reference for the life of the pipeline.

EXHIBIT A
(1 of 3)

Instructions for completion of Form C 1282-9 "Surface Potential Survey," page 3 of this Exhibit, is as follows:

Key	Item	Description
1.	"Heading"	Provide information relative to the survey.
2.	Station	Indicate location in feet of the front half cell from beginning point of survey.
3.	Surface Type	Indicate surface conditions above pipeline, using codes at bottom of form. Also, indicate direction of survey travel.
4.	Reading	Record the ten foot half cell surface potential reading, polarity, and magnitude. Note: A five-foot spacing is used when a positive-to-negative polarity change occurs within a ten-foot spacing.
5.	SD MV (Slide Drain)	Record polarity, magnitude, and direction of half cell from pipe under appropriate column, "Side drain readings" are usually taken when a positive-to-negative polarity change occurs within a ten-foot spacing.
6.	Soil Resistivity	Readings usually taken at significant positive-to-negative polarity changes.
7.	Pipe to Soil	Record pipe-to-soil readings, where appropriate.
8.	C. F. (Corrosion Factor)	Calculate and record corrosion factor by dividing the MV drop by soil resistivity.
9.	Features and Remarks	Indicate geographic landmarks of front half cell; e.g., electric poles, fire plugs, driveways, streets, service lines, test stations, line markers, valves, insulators, leak repairs, etc. Note that the location shown is relative to only the front half cell. A notation such as a -4 pole 543A2 would mean that the front half cell was placed four feet beyond pole number 543A2. A notation such as a +3 sidewalk 566 Winchester Drive would mean that the front half cell was placed three feet behind (before) the center line of the sidewalk to 566 Winchester Drive. The travel direction of the survey must be recorded.

EXHIBIT A
(2 of 3)

Key	Item	Description
10.	Mag Anode Type Weight	Size magnesium anode to be installed.
11.	Date Installed	Record date magnesium anode was installed. If a leak was found during the installation of an anode record the leak order number below the date the anode was installed.
12.	Additional Remarks	Self-explanatory.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Surface Potential Survey	Standard Number: **GS 1430.130**
Supersedes: 05/01/2010		Page 6 of 7

**EXHIBIT A
(3 of 3)**

COLUMBIA GAS
Distribution Companies

SURFACE POTENTIAL SURVEY

DATE:
STARTED__________19___

COMPLETED__________19___ TOWN __________ (1) __________ SHEET NO.______ of _____

PIPE SIZE__________ STREET__________ MAP NO.__________

PRESSURE__________ __________ SURVEY BY __________

STATION	SURFACE TYPE (a)	READINGS mv 10'	READINGS mv 5'	SD R	MV L	SOIL RESISTIVITY (OHM-CM)	PIPE TO SOIL (VOLTS)	C.F.	FEATURES AND REMARKS	MAG ANODE TYPE WEIGHT (b)	DATE INSTALLED
00											
10											
(2) 20	(3)	(4)		(5)		(6)	(7)	(8)	(9)	(10)	(11)
30											
40											
50				PIPE							
60											
70											
80											
90											
00											
10											
20											
30											
40											
50				PIPE							
60											
70											
80											
90											
00											
10											
20											
30											
40											
50				PIPE							
60											
70											
80											
90											
00											
10											
20											
30											
40											
50				PIPE							
60											
70											
80											
90											

ADDITIONAL REMARKS: (12) __________

(a): A-ASPHALT, C-CONCRETE, S-SOIL, G-GRAVEL, D-DRY
(b): EX-EXISTING, P-PROPOSED
FORM C 1282-9 CSD (2-87)

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Test Method for Establishing 100 mV Polarization Shift Criterion	Standard Number: GS 1430.140
Supersedes: 05/01/2010		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The "100 mV Polarization Shift" criterion (see GS 1420.020 "Criteria for Cathodic Protection") uses pipeline polarization formation or decay to assess the adequacy of cathodic protection (CP). This test method is especially useful for bare or ineffectively coated pipe.

The section of pipeline being tested should be electrically continuous, isolated from other structures and the position of any insulated joints should be known.

This test should only be completed if anodes are not connected directly to the pipeline test section, unless IR drop coupons are utilized.

Typically, this test is used on impressed current systems.

The 100 mV polarization shift criterion should not be used in areas subject to stray currents because CP currents might be insufficient to mitigate corrosion. In addition, the 100 mV polarization shift criterion should not be used for pipelines at risk for stress corrosion cracking (SCC). The pipe-to-soil potentials for cracking are in the range of the native potential and -850 mV CSE, so during the testing process to establish the 100 mV criterion, pipe-to-soil potentials may fall into this range, making the pipeline more susceptible to SCC.

2. TEST METHOD

Verify that cathodic protection equipment has been installed and is operating properly. Time should be allowed for the pipeline potentials to reach polarized values.

Install and place into operation interrupter equipment at all DC current sources influencing the pipe at the test site. If multiple DC current sources are involved, then the interruption of all influencing sources shall be synchronized. Interrupting the known CP source(s) will reduce the IR drop and allow the polarization to be measured after the "instant off" cycle.

There may be a spike in the potential reading immediately after interruption of the CP source as the result of inductive effects of the pipeline and the CP system. The spike typically lasts approximately 100 to 200 milliseconds; therefore the "OFF cycle" should at a minimum be 300 milliseconds in duration.

Refer to GS 1430.110 “Pipe to Soil Potential Measurements” to reduce reading errors as much as possible.Measure and record the pipe-to-soil “on” and “instant off” potentials and their polarities with respect to the reference electrode at all designated test stations. The “instant off” pipe-to-soil potential is the “baseline” potential from which the polarization decay is to be measured, this is considered the peak of the CP polarization.

Turn off sufficient CP current sources that influence the pipe at the test station until at least 100 mV cathodic polarization decay has been measured from the point of the “instant off”. Continue to measure and record the pipe-to-soil potential until it either:

a. has become at least 100 mV less negative than the “off” potential; or

b. has reached a stable depolarized level.

Full depolarization of a poorly coated or bare pipeline may take days to weeks to achieve. However in most cases, full depolarization is not needed. If depolarization of 50 mV is not measured within a few hours, it becomes questionable if depolarization of 100 mV will be achieved.

The period of measuring the polarization decay of the system should be minimized as much as possible due to extensive periods of no CP being applied during this time. For most situations, 24 hours without CP is acceptable to achieve depolarization of 100 mV. If more time is needed, consult with the local corrosion leadership.

Cathodic protection shall be judged adequate at the test station if 100 mV or more of polarization decay is measured with respect to a standard reference electrode.

3. NEW STEEL PIPE

Typically for new pipelines, either the -850 mV Polarized Potential or the -850 mV “On” Potential with IR Drop Considered criterion is used for cathodic protection.

However, if the 100 mV Polarization Shift criterion is used for new pipelines, the native potential measurements shall be taken before the CP source is added. The 100 mV polarization formation criterion can be applied after measuring the IR drop (“instant off” cycle). If the “instant off” cycle potential reading is more negative than the native potential by 100 mV, the pipeline can be considered achieving a polarization formation of 100 mV or greater, which is considered to be cathodically protected.

4. RECORDS

The results of the test method establishing the 100 mV Polarization Shift Criterion (for new or existing pipelines) shall be documented and kept for the life of the pipeline in local corrosion files for future reference and troubleshooting purposes.

Update applicable work management system records (e.g., test stations, bonds), or equivalent, with acceptable limits for cathodic protection.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Soil Resistivity Measurements	Standard Number: GS 1430.210
Supersedes: 05/01/2010		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Soil resistivity measurements are used to determine the resistivity of the soil at or near an existing or proposed pipeline.

Measuring the electrical resistivity of the soil is necessary to:

a. design impressed current or sacrificial anode ground beds;

b. determine the best location for ground beds or distributed anodes;

c. estimate the voltage requirements for impressed current anodes or current output of sacrificial anodes; and

d. predict the probable corrosiveness of soils when combined with other information (e.g., pipe-to-soil potential measurements).

Generally, there are three methods available for measuring soil resistivity: the four-pin method, the Collins rod method, and the soil box method.

2. FOUR-PIN METHOD

Typically, the four-pin method is used to design a new cathodic protection system.

The average soil resistivity of a hemisphere of earth is measured using the four-pin method. The four pins are placed in the soil in a straight line at equal intervals perpendicular to the pipeline. The spacing of the pins determines the radius of the hemisphere being tested, which can be adjusted to test near the top and bottom of the existing or proposed pipeline. The radius of this hemisphere is distance "A" (the distance between the inside pins). Refer to Figure 1.

If a steel pipeline or other metallic structure lies within the sphere to be measured, measurement errors will result. It is important to align the pins perpendicular to the pipe, and it is recommended that the nearest pin be no closer than 1/2 "*a*" to the pipe (or any other metallic structure). The pin spacing must be of equal distance to obtain accurate results.

The rods shall penetrate the surface to a depth no greater than 10% of the pin spacing . If soil appears dry or of a material of high resistance such as gravel, frost or other materials, drive the rods deeper until good soil contact is made. In extremely dry soil, wetting the pin area may improve contact of the pins with the soil. Oxidation on the surface of the rods shall be removed before use.

The four-pin method should not be used for depths greater than 30 feet.

Current is applied to the outer pins creating a voltage drop that is measured by the inner pins. This voltage drop is measured and used to determine the soil resistivity in ohms-cm.

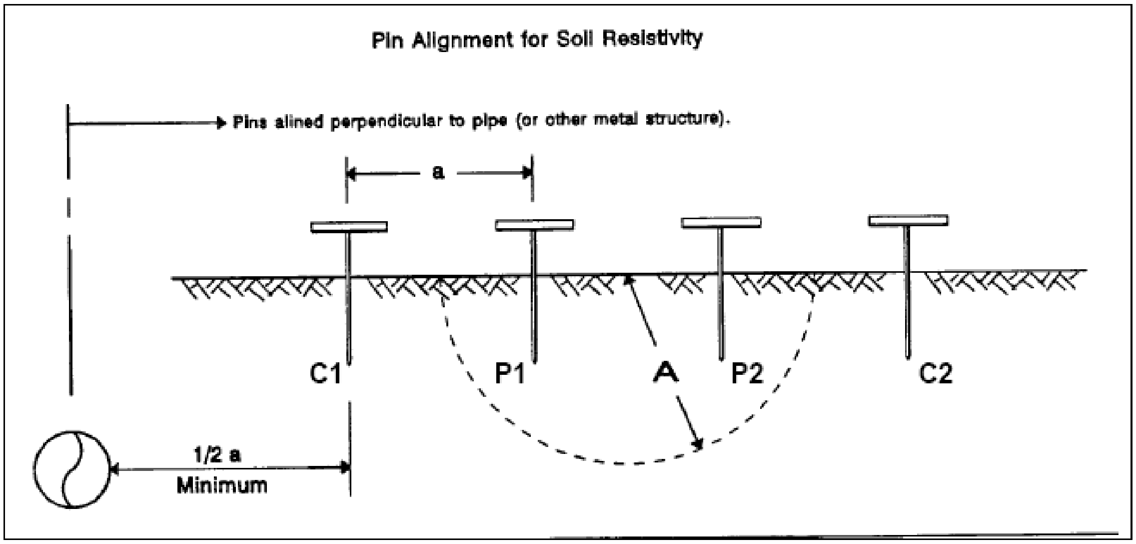

Figure 1: Four-Pin Method

2.1 Average Soil Resistivity

The average soil resistivity can be calculated by using the following formula:

$\rho = 191.5\, a\, R$

Where,
ρ = soil resistivity in ohms-cm,
a = pin spacing in feet, and
R = soil resistance in ohms.

2.2 Barnes Layered Method

To pinpoint soil resistivity, the Barnes Layered method may be used to more accurately determine the soil resistivity at the pipe depth.

$$R_{1Barnes} = R_1$$

$$R_{Layer1} = R_{1Barnes} \bullet D_1 \bullet 191.5$$

$$R_{2Barnes} = \frac{R_1 \bullet R_2}{R_1 - R_2}$$

$$R_{Layer2} = R_{2Barnes} \bullet D_2 \bullet 191.5$$

$$R_{3Barnes} = \frac{R_2 \bullet R_3}{R_2 - R_3}$$

$$R_{Layer3} = R_{3Barnes} \bullet D_3 \bullet 191.5$$

Where,
D_1, D_2, & D_3 = thickness of each layer in feet (typically equal to the pin spacing),
R_1, R_2, & R_3 = average soil resistance in ohms for each D,
$R_{1Barnes}$, $R_{2Barnes}$, & $R_{3Barnes}$ = soil resistance in ohms for each layer, and
R_{Layer1}, R_{Layer2}, & R_{Layer3} = soil resistivity in ohms-cm for each layer.

3. SINGLE-PROBE (COLLINS ROD) METHOD

The single-probe (Collins rod) method is typically used at excavated sites and basically takes a soil resistivity reading in the immediate area (i.e., approximately the size of a softball) of the tip of the rod.

The single-probe method is a two point resistivity measurement. A resistance measurement is made between the tip of the probe and the shank of the probe rod after insertion in the soil. An audio receiver is generally hooked into the Wheatstone bridge, which allows the operator to hear an audible AC tone until the bridge circuit is balanced and a null occurs. At the point of null, the resistance can be read from the instrument.

The resistivity measured by this method is only representative of the small volume of soil around the tip of the probe and should not be thought of as typical for all of the total soil area in question. Multiple measurements within the area of interest will increase the validity of this method by increasing the sample size if the point of interest can be reached with the probe. Single probe measurements are generally used for comparative purposes or in excavations to locate anodes in the lowest resistivity soil. This method is also useful where the close proximity of other underground metal structures make the use of the four-pin method impractical.

4. SOIL BOX METHOD

Figure 4 represents the soil box method, which is primarily used for resistivity measurements during excavations (e.g., drilling a deep well anode system). Resistivity can be determined at varying levels of depth allowing accurate measurement of various strata of soil as the boring progresses. Also, accurate data can be measured from soil taken at pipeline depth during the installation of a new pipeline. However, the accuracy of a soil box depends on how closely the original conditions are recreated in the soil box (e.g., compaction, moisture).

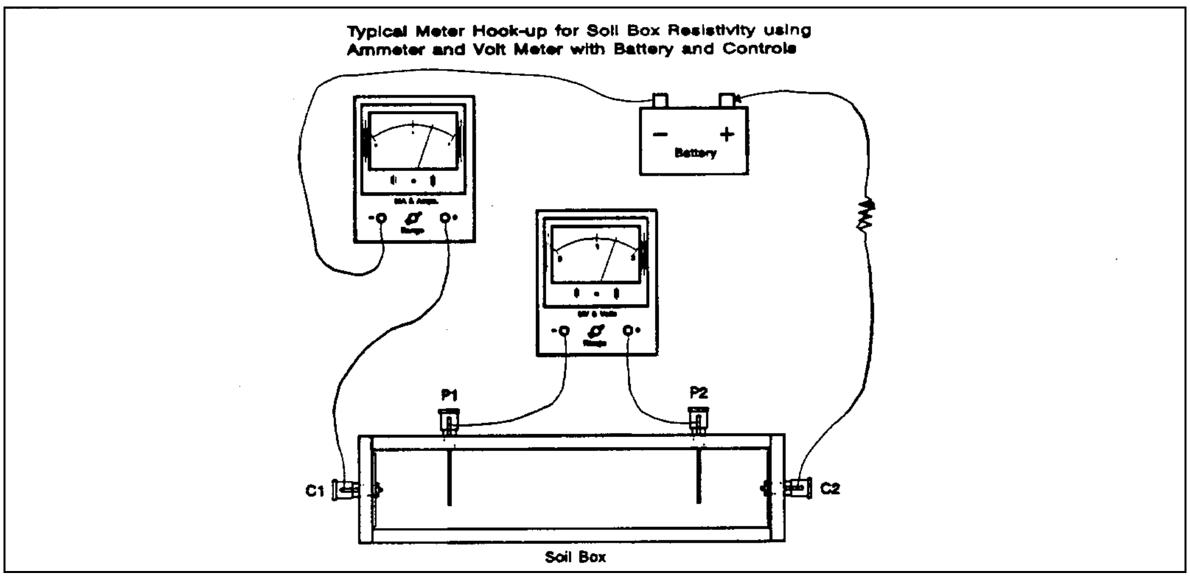

Figure 4: Soil Box Resistivity

A soil sample is taken from the pipeline location and is placed into the box for measurement. The box will have four points of connection for applying current from the soil resistivity measurement unit on the outside and measuring the voltage drop across the median of the material at the inside terminals.

The calculation is performed on the instrument, when the unit is energized and reaches a null reading on the indicator.

NOTE: Some soil resistivity instruments will have a multiplier in the resistance calculation. Refer to manufacturer's instructions for use of a multiplier.

5. EQUIPMENT

The conductors used shall be insulated and of low resistance, and color coded or marked for proper identification of connections.

If a spool is used, the reel shall be specifically made for use with the soil resistance meter application. The spool shall have four connecting points for connecting the leads to the soil resistance meter, the connection points shall be color coded for proper connection.

All connections and wire shall not contact the earth during the test.

Use rods recommended by the manufacturer of the soil resistance meter.

6. RECORDS

The location of soil resistivity measurements and the method used to determine the soil resistivity should be kept for reference, as needed.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Current Flow Measurements**	Standard Number: **GS 1430.220**
Supersedes: 05/01/2010		Page 1 of 8

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The measurement of current flow is an important part of corrosion control. This type of measurement shows the direction and magnitude of DC current flow. It is useful during the initial evaluation and in analyzing malfunctions in cathodic protection systems. Measuring current is used directly in:

a. evaluating equipment such as rectifiers;

b. analyzing and solving stray current problems;

c. checking current distribution for defects such as short circuits; and

d. checking the effectiveness of insulators.

2. TEST METHODS

Current flow measurements are made by two methods as follows:

a. directly by connecting an ammeter in series in a circuit, such as between an anode wire and a pipe wire; and

b. indirectly by measuring the voltage drop across a resistance, such as a shunt inserted in a circuit or the span of a section of pipeline (IR drop method).

Unlike alternating current, the direction of direct current can always be determined. Knowledge of the direction of the current is required for proper analysis in corrosion control work. The direction of direct current can be determined by observing the polarity of the test lead connections.

For consistency in these practices and to reduce inadvertent polarity and current flow errors, the pipeline (or structure of interest) should always be connected to the positive (+) meter terminal. If this results in an incorrect measurement or reversed polarity condition, it shall be investigated prior to proceeding with the measurement.

2.1 Direct Ammeter Reading

For direct current readings, the circuit must be opened and the lead wires connected to the terminals of the ammeter. The ammeter used must have a sufficient capacity range for the current to be measure or the instrument will be damaged. Most general purpose ammeters have some over-range protection, generally in the form of a replaceable fuse, but this may not protect the meter sufficiently. The magnitude of the current flow using this method is read directly from the ammeter. For multiple range meters, always set the selector at the maximum range first and reduce this setting as needed.

2.2 Indirect Method with Shunt

This method is typically used to determine the following:

a. current flow measurements for individual anode outputs in a ground bed system,

b. current drain for interference bonds, or

c. current output for rectifiers.

Larger currents can be measured by using an external shunt (calibrated resistance) and a voltmeter to make current measurements. Shunts are accurate because they are fabricated specifically for this use and, most often, mass produced. They are convenient because they can be left connected into the circuit and measurements can be repeatedly made with little effort. Permanently connected shunts are found in virtually all rectifier circuits. Shunts are rated so that a given current flow through it will cause a calibrated voltage drop across it. In many cases, smaller shunts from 1 to 5 ampere total current capacity are supplied with a millivolt constant (per ampere) imprinted on the shunt rather than the rating. The ratings must still be known for the shunt since a 1 ampere shunt will not work in a 2 ampere circuit for obvious reasons.

The following table shows some common commercially available shunt resistances and "k" factors.

Shunt Resistance (ohms)	Amps per Millivolt-Constant (*k*)
0.001	1.0
0.01	0.1
0.1	0.01
1.0	0.001

For shunts such as these, the ampere per millivolt constant “*k*” is obtained by dividing the rated capacity of the shunt amperes by the total voltage drop. This makes them convenient for general use. For a 5 ampere, 50 millivolt shunt; the constant would be 0.1 amperes per millivolt. The magnitude of current flow across these shunts is calculated from the millivolt meter reading multiplied by the amperes per millivolt constant "*k*" for the size of the shunt used. The formula is:

$$I = mV(k) \tag{1}$$

Where,

I = Current flow in amperes

mV = Meter reading in millivolts

k = Amps per millivolt-constant for shunt

For example, if a 5 ampere, 50 millivolt shunt with an amps/millivolt constant of 0.1 were used and the volt meter shows 26 millivolts across the shunt then,

$$26\,(0.1) = 2.6$$

the current flow is 2.6 amperes.

Sometimes shunts are expressed in ratios, such as "15 amps = 50 mV." In these cases, k can be calculated as follows:

$$\frac{15\text{ (amps)}}{50} = \frac{50\text{ (mV)}}{50}$$

or

0.3 amps = 1 mV

The ampere per millivolt constant "k" will be 0.3 for the shunt.

Therefore, if your voltage reading across the shunt is for example 28 mV, then your current output is:

0.3 amp/mV x 28 mV = 8.4 amps

If only the resistance of the shunt is known, current can be calculated by obtaining the voltage (millivolt) reading across the shunt, by the following formula (Ohm's law):

$$I = \frac{E}{R} \tag{2}$$

2.3 Indirect Method with Voltage Drop

This method may be used when determining coating damage over a large span of a directional bore.

This method should only be used on a span where the span footage (including laterals) is known, with no insulators or high resistance fittings or couplings in the span. If this information is unknown, then it is recommended to validate continuity with a fault locator or another approved test method. It is also recommended to use a high impedance meter (10 mega ohms or more) so that external resistance of the span does not exceed the internal resistance of the meter.

The "voltage drop" (IR Drop) method is a means of measuring the direction and magnitude of current flow along a pipeline with voltage measurements. The same principle is applied as with the use of a shunt except that the voltage drop along the pipeline span may not be known. The constant for the span may be estimated with the use of tabulated data or it can be calculated from measurements taken.

An accurate method for finding "k" is shown in Figure 2. Calibration of the span is accomplished by impressing a current across the two outside test wires. This current should be impressed in the same direction as the natural current flow already on the pipeline. When the current is impressed and the pipe span has a definite resistance, a change in voltage will be observed on the voltmeter across the two inside test leads. The voltage change from an applied current is normally expressed as delta voltage (Δ volts).

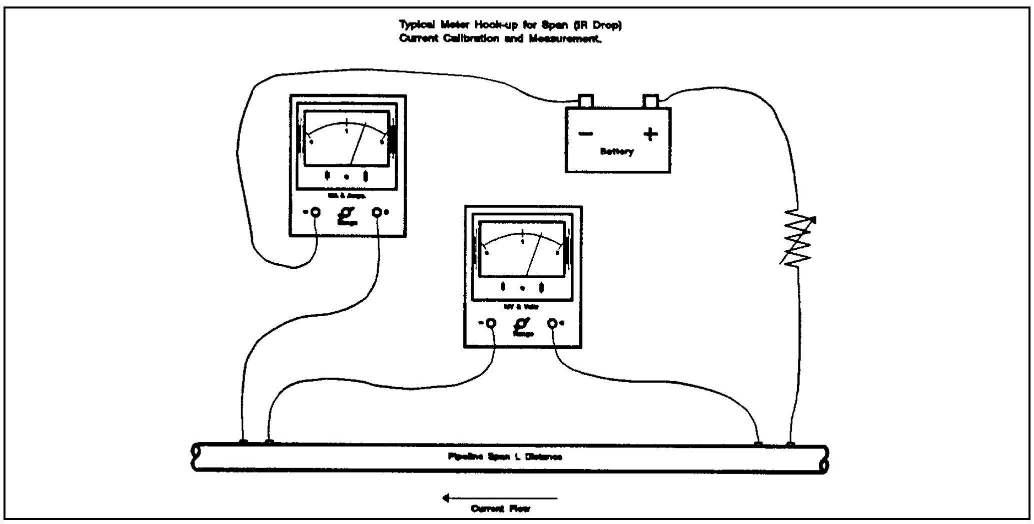

Figure 2 Span Calibration.

The constant "*k*" in this case can be calculated once the pipe span resistance value (R) between two test point connections is known. The span resistance is calculated by:

$$R = \frac{E_{ON} - E_{OFF}}{I_B} \qquad (3)$$

Once "R" is determined, the current flow can be calculated from Ohm's law by:

$$I = \frac{E_{OFF}}{R} \tag{4}$$

For later convenience, "*k*" is determined by:

$$k = \frac{I_B}{E_{ON} - E_{OFF}} \tag{5}$$

Where,

R = Span resistance in ohms

E_{ON} = Voltage measured with current on in millivolts

E_{OFF} = Voltage measured with current off in millivolts

I_B = Current impressed across span in amperes

I = Current flow across span in amperes

k = Amperes per millivolt constant

A variation on this method may be used where the current impressed across the span is in opposition to the natural currents flowing on the pipeline. The current value is increased until the voltmeter moves from its natural potential until it reads zero on the meter scale. This method may not be practical for large current flows. The calculation to obtain k by this method is:

$$k = \frac{I}{E_0} \tag{6}$$

Where,

k = Amperes per millivolt constant

I = Current in amperes required to obtain zero voltage reading

E_0 = Voltage reading with current off in millivolts

In some cases, it is not necessary to measure the magnitude of current flow with great accuracy since the values are normally used for comparative purposes. The table in Exhibit A may be used in such cases to estimate the span resistance and then to calculate the current flow. If accurate current flow measurements are desired, then the span must be calibrated. Normally, only permanent test points are calibrated. This type of test point requires four test wires or two test points with two wires installed for this purpose. For either method, once the resistance per unit length or "k" is determined, the current value can be calculated using equation (4).

Another method which may be used for estimating the span resistance from tabulated pipe data where only the weight per foot is known is given by the following equation:

$$R_S = \frac{0.2158}{W} \qquad (7)$$

This gives the resistance per 1000 feet.

Then, for the specified span length,

$$R = \frac{R_S}{1000}(L) \qquad (8)$$

Where,

R_S = Structure resistance in ohms (W) per 1000 foot

W = Weight of pipe in pounds per foot

L= Span length between voltage measurement in feet

Once a span has been calibrated, the resistance known, and k value calculated, it will not change as long as the condition of the pipeline or permanent test leads do not change. Care must be exercised to ensure that no service line, lateral, high resistance or insulating joint is included in the span; otherwise the measurements will be in error.

3. RECORDS

Current flow measurements required in accordance with GS 1430.020 “External Corrosion Control Monitoring” (e.g., rectifier current output, current drain for interference mitigation) shall be kept in the Company’s work management system, or equivalent.

Other current flow measurements taken for purposes, such as determining coating effectiveness for directional bore applications or determining high resistance couplings or insulators within the pipeline, should be kept in the Company's work management system, or equivalent, for future reference.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Current Flow Measurements	Standard Number: GS 1430.220
Supersedes: 05/01/2010		Page 8 of 8

EXHIBIT A

STEEL PIPE DATA

Nom. Pipe Size IN INS.	Outside Diam. IN INS.	Wall Thickness IN INS.	Weight in lbs. Per Ft.	Surface Area Sq. Ft. Per Ft.	Resist-ance Mohms Per Ft.	"K" Amps/mv. on 1 Ft. of Pipe
1	1.310	.179	2.17	.344	100.0	10.0
1-1/4	1.660	.140	2.27	.435	95.2	10.5
		.191	3.00		72.2	13.9
2	2.375	.154	3.65	.622	59.2	16.9
		.188	4.38		49.3	20.3
		.218	5.02		43.0	23.3
3	3.500	.125	4.51	.916	47.9	20.9
		.188	6.65		32.5	30.8
		.216	7.58		28.5	35.1
		.300	10.25		21.1	47.6
4	4.5000	.125	5.84	1.178	37.0	27.0
		.188	8.66		24.9	40.2
		.237	10.79		20.0	50.0
		.337	15.00		14.4	69.4
5	5.190		12.49	1.450	17.3	57.8
	5.560	.258	14.60		14.8	67.6
	5.560	.375	20.80		10.4	96.2
6	6.625	.156	10.78	1.735	20.0	50.0
		.188	12.92		16.7	59.9
		.219	14.98		14.4	69.4
		.280	18.97		11.4	87.7
8	8.625	.172	15.53	2.258	13.9	71.9
		.188	16.94		12.8	78.1
		.250	22.36		9.66	103.5
		.322	28.55		7.57	132.1
10	10.750	.188	21.21	2.814	10.2	98.0
		.250	28.04		7.70	129.9
		.279	31.20		6.92	144.5
		.365	40.48		5.34	187.3
12	12.750	.203	27.20	3.338	7.94	125.9
		.250	33.38		6.47	154.6
		.375	62.58		3.45	289.9
16	16.000	.250	42.05	4.189	5.14	194.6
		.312	58.94		3.66	273.2
		.375	62.58		3.45	289.9
18	18.000	.250	47.390	4.712	4.55	219.8
		.312	58.94		3.66	273.2
		.375	70.59		3.06	326.8
20	20.000	.250	52.73	5.236	4.10	243.9
		.312	65.60		3.29	304.0
		.375	78.60		2.75	353.6

Based on steel pipe resistivity = 215.8 micro-ohms (Pound Foot)

Current (amperes) = $\frac{1000}{\text{Resistance (micro-ohms/ft.)}}$

Resistance (micro-ohms/ft.) = 215.8 /weight per foot (pounds)

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Current Requirement Test	Standard Number: GS 1430.230
Supersedes: 05/01/2010		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

A current requirement test is completed to determine the amount of anodes or impressed current output needed for cathodic protection (CP) of a new or existing pipeline. Current requirement tests are essentially the same regardless of whether the pipe is newly installed or not.

However, current required for new or replacement pipeline installation is typically determined by estimating the coating effectiveness and estimating the required current density (refer to GS 1420.080 “Corrosion Control Design – Sacrificial (Galvanic) Anode System” or GS 1420.090 “Corrosion Control Design – Impressed Current System.”

Guidance for performing tests to determine the current required to provide cathodic protection is covered by this procedure.

2. PRIOR TO CURRENT REQUIREMENT TEST

Prior to actual testing, a realistic estimate of the current required for protection should be made. When the test is initiated, these initial results must be compared with the estimates. If this comparison shows higher than anticipated current requirements (by a significant amount), then the test should be suspended. The pipeline should be checked for electrical isolation or short(s) before proceeding further.

If testing for a proposed impressed current system, the location where the temporary current is applied should be in the same vicinity that the permanent source will be located. Choose a location where the following items are considered:

a. right-of-way can be secured;

b. permanent power can be available if needed; and

c. preliminary interference tests can be conducted.

Prior to establishing the temporary ground bed and DC power source, a close interval survey (CIS) shall be completed (refer to GS 1430.120 “Close Interval Survey”) to determine the low point(s) of CP. For new pipelines where CP has not been applied, obtain native pipe-to-soil potentials (refer to GS 1430.010 “Evaluation of New Cathodic Protection Systems”). For existing pipelines, obtain existing pipe-to-soil potentials before additional CP is applied. These measurements can be used to estimate (see above) and determine (see Section 5.3 below) current required for protection for the entire footage assigned to the test station facility.

3. ESTABLISH TEMPORARY GROUND BED AND DC POWER SOURCE

To make the test, a temporary ground bed is established and a DC power source is used to drain current from the pipeline of interest to the ground bed. A battery is normally used as the DC power source, or in the case of larger initial current requirements, a portable rectifier powered by a portable generator or a DC welder or inverter may be used. The "temporary" ground bed may be an existing isolated metallic pipeline as long as it is sufficiently remote from the pipeline of interest. Temporary ground rods may be used as the ground bed. The temporary ground bed should be remote to the pipeline, so that the measurements do not include voltage gradient from the ground bed.

Multiple temporary ground beds may be established in high resistivity soils to distribute current evenly along the pipeline.

4. TEST CONNECTIONS

To make the electrical connections for the test, start by connecting the positive terminal of the DC power source to the temporary ground bed. Then connect the negative to the pipeline through an ammeter and a device such as a rheostat or variable resistor for controlling the current. All of these items must be sized accordingly for the amount of current output estimated for the test. The interrupter is connected with a timing cycle that will produce an identifiable "on" and "off" cycle.

5. TEST METHOD

Using the current control device, the drain current is adjusted until a measurable change in potential can be observed at all of the predetermined test points.

5.1 Pipe-To-Soil Measurements

As the test proceeds, pipe-to-soil readings are taken at all of the predetermined test points. Normally this includes all points of possible connection to the pipeline such as:

a. test points;

b. piping at meter and regulator stations;

c. customer service lines at risers; and

d. other foreign structures.

The readings should be recorded in a logical manner so that later interpretation and analysis can be performed. Each reading must be noted as to the "on" and "off" as determined in the cycle timing of the interrupter. The voltage change (Δ Volts) at each point on the pipeline of interest should be computed as the readings are taken and their current requirements calculated. This allows for any abnormal results to be recognized as the test is being conducted and results can be rechecked while the test apparatus is still in place and operating.

5.2 Notation of Problems

Any problems should be noted at this time such as:

a. discontinuous service lines;

b. shorted casings;

c. ineffective insulators;

d. interference with other structures;

e. higher than anticipated calculated current requirement; and

f. extremely dry and/or frost conditions.

5.3 Determination of Current Requirement

It is typical to use the -850 mV “On” Potential with IR Drop Considered criterion for cathodic protection. The current requirement then can be measured by the temporary ground bed output when the potential measurements of the selected test points reach the desired pipe to soil potential reading (e.g., -1.20 volt).

A review of all of the delta voltage readings may indicate the requirement of multiple current sources distributed evenly along the pipeline circuit.

If tests are completed in conditions with high soil resistivity (e.g., extreme dry and/or frost, sand backfill), test results may indicate higher current requirements than what is actually needed. In these cases, a recommendation should be made based on the judgment of corrosion personnel on a more realistic current requirement. After remediation, corrosion personnel should follow-up during more suitable conditions to see if additional CP is needed.

NOTE: Large current requirements in good conditions may indicate a short. In high resistivity soils, it is difficult to differentiate between high resistivity soils and possible shorts, so troubleshooting is necessary (refer to GS 1430.410 “Cathodic Protection Troubleshooting Methods.”

6. RECORDS

Current requirement tests should be kept in the Company’s work management system, or equivalent, for future reference and troubleshooting purposes. Information such as native or existing pipe-to-soil potential measurements, location of temporary ground bed(s), estimated current requirement, current output of temporary power source(s), pipe-to-soil potential measurements at predetermined test points, notation of problems, etc. should be documented.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Verifying Electrical Continuity and Isolation	Standard Number: **GS 1430.250**
Supersedes: 03/01/2010		Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

This standard provides guidance on verifying electrical continuity and electrical isolation for cathodic protection purposes.

The following methods may be used to verify either continuity or isolation.

2. FIXED HALF CELL TEST

Figure 1 below illustrates the procedure for checking continuity/isolation. One method used quite often is to place the half cell at one location, such as at "A", and obtain a reading. Then, without moving the half cell, connect the positive meter lead to another location (in this case "B") normally with the use of a wire reel and take another reading. If the readings are the same or essentially the same (within 100 mV difference), it is an indication that continuity exists. The only factors that will affect the reading on a continuous line would be the additional resistance added by the reel and resistance of the pipeline from points "A" and "B" which are included in the second reading. The best practice is to have the reel, if needed for any readings, connected into the circuit for all of the readings. The external resistance of the test leads and pipe span cannot be an appreciable percentage of the internal resistance of the meter used; otherwise the reading will not be identical nor accurate. If corrected measurements are not identical, then an unknown resistance, such as an insulator or a high resistance joint, might be suspected.

Effective Date: 03/01/2010	**Verifying Electrical Continuity and Isolation**	Standard Number: **GS 1430.250**
Supersedes: N/A		Page 2 of 7

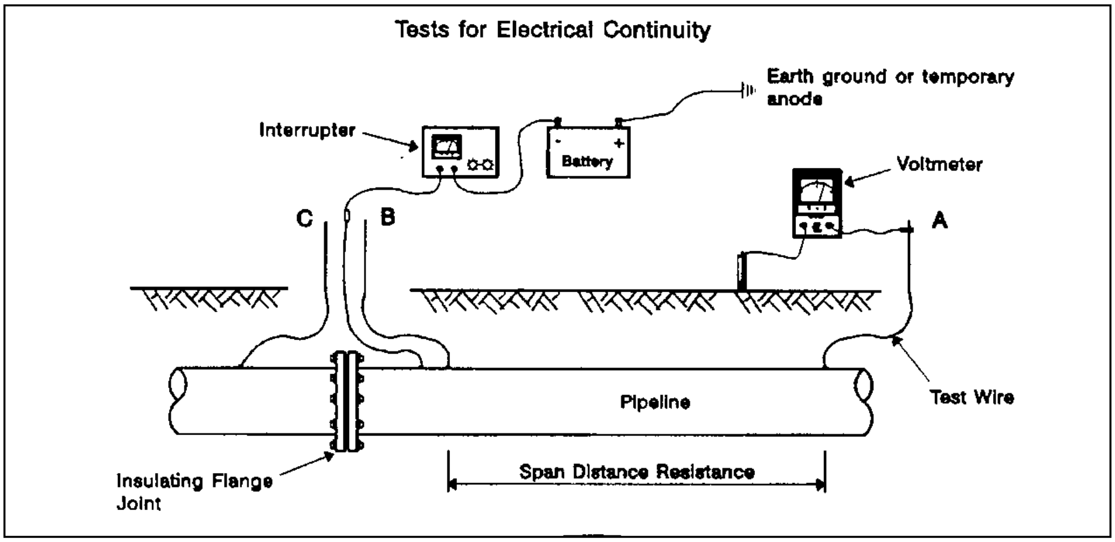

Figure 1: Continuity Testing

3. INTERRUPTION MEASUREMENT

Another method used to check continuity is to add enough current to the line to cause a voltage change along the span in question. An interrupter shall be included in the circuit with a known cycle time of varying "on" and "off" duration. By taking readings along the pipeline and noting their magnitude and direction, it can normally be determined if there is continuity or isolation. In the illustration, when current is applied at point "B" as shown, the reading at point "A" should coincide with a reading taken at point "B" in the time cycle. The pipe-to-soil reading at point "C" should remain the same or go positive during the "on" cycle if the insulator is effective in most cases.

NOTE: Temporary ground bed needs to be remote and isolated from the pipeline being tested, so that the ground bed voltage gradient is not picked up during the reading.

When testing casing/carrier pipe isolation, take “on” and “off” cycle pipe-to-soil potential readings on the casing. If the casing cycle indicates the peak potentials at the “On” cycle, this may indicate that the casing is shorted with the carrier pipe. If the casing cycle indicates the peak potential at the “Off” cycle, then the casing is not shorted with the carrier pipe.

4. CHECKING FOR CONTINUITY/ISOLATION WITHIN COMPLEX PIPING SYSTEMS

Tests for electrical continuity and isolation are important to ensure that the observed measurements are truly representative of the line of interest. Figure 2 below illustrates the effects of an unknown insulated joint when taking over-the-line pipe-to-soil measurements. As the reference cell moves over the insulated joint, the potentials measured are no longer representative of the local earth gradients of the pipeline. The farther from the joint the measurements are made, the more they become remote observations until at some point they become more representative of remote earth.

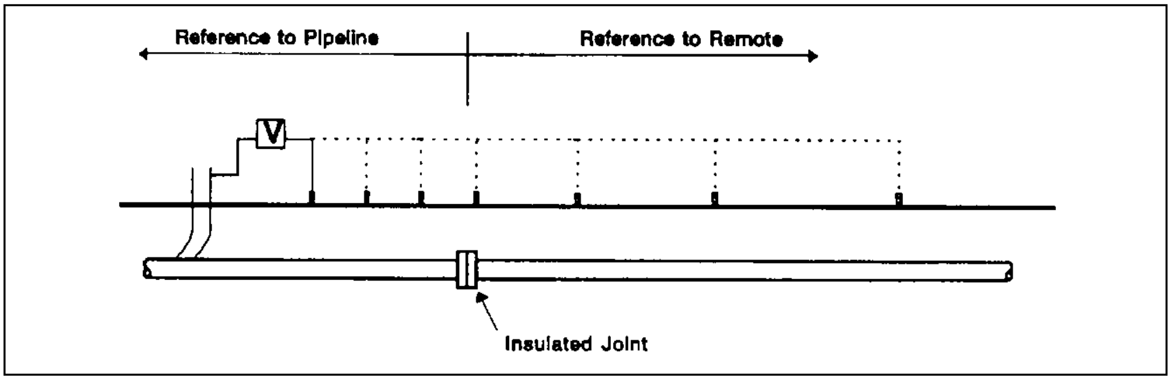

Figure 2: Local and Remote Reference Points

If the observer is unaware of this situation and continues to take measurements beyond the insulated joint, the readings would be in error and misleading in any analysis. Using the methods described in this section (illustrated in Figure 1) and in the following paragraphs will eliminate the possibility of error in this situation.

Checking for resistance as it is done in normal electrical circuits will not work for structures immersed in an electrolyte because the electrolyte acts as if it were a conductor. With pipelines, current can be shunted through the soil. This is a particular problem in testing the effectiveness of buried insulators.

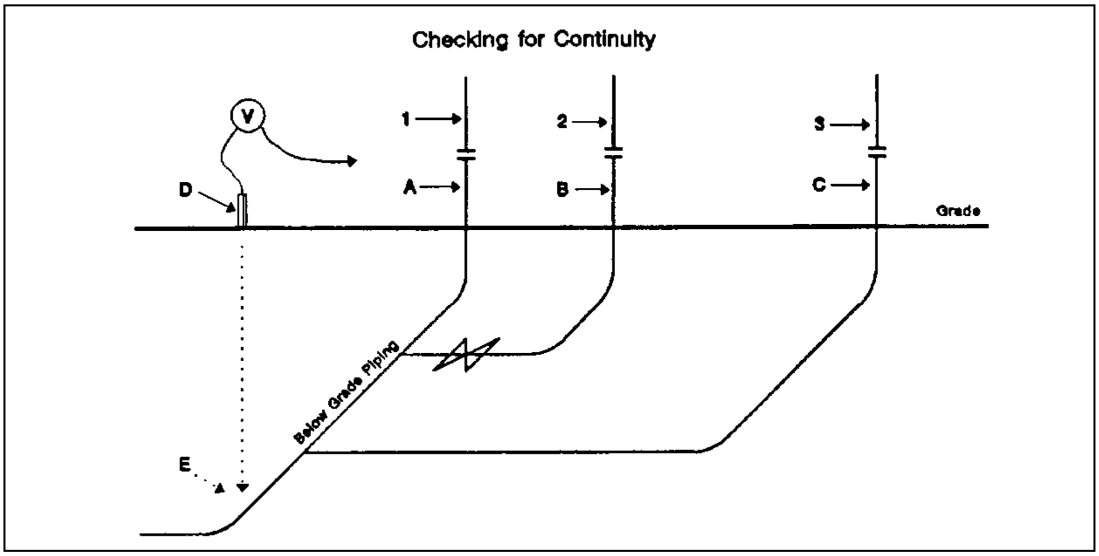

Figure 3: Method for Checking Continuity

Figure 3 above further illustrates a method of checking for continuity. Where there is any question of continuity along the pipeline and in large or complex stations, this method should be used. A reference cell is placed at a convenient location, which in this case is point "D." For the purposes of this illustration, this point is located directly over point "E" on the below grade piping. Using a reel, the negative of the volt meter can then be connected to points "A," "B" and "C" in turn. At each point, the voltmeter should give an identical reading. The only time this would not be the case would be if there was an appreciable resistance between any of the points. This would mean one of the following:

a. there is an insulating joint in the below grade piping;
b. a high resistance connection is located in the piping (buried flange or compression coupling); and/or
c. the piping systems are not connected.

5. SPECIAL SITUATIONS

5.1 Testing of Insulators

GS 1420.530 “Installation of Insulators” requires testing an insulator after installation to ensure that insulation has been achieved. The following methods may be used to verify electrical isolation.

5.1.1 Voltage Test

Connect the voltmeter lead to points "1," "2" and "3" in turn (as shown in Figure 3 above). A completely different reading should be obtained from those observed earlier when connected to the below grade piping. The readings obtained from points "1," "2" and "3" may or may not be identical to each other. It would be dependent on whether or not a metallic contact exists between them, and if so, if any resistance existed in the connection circuit. When performing this test, make sure that there are no high resistances in the connections to the pipeline (or structure), in the test leads or in the contact of the half cell itself.

If the difference in potential on either side of an insulator is greater than 100 mV, the isolation is effective. Further testing may be needed if the difference is less than 100 mV.

5.1.2 Continuity Tester

A continuity tester can be used to verify electrical isolation at above ground insulators (e.g., at meter settings), where it is cost effective to replace an insulator that is not working properly, or on insulators prior to installation. Two types of continuity testers are illustrated in Figure 4 below.

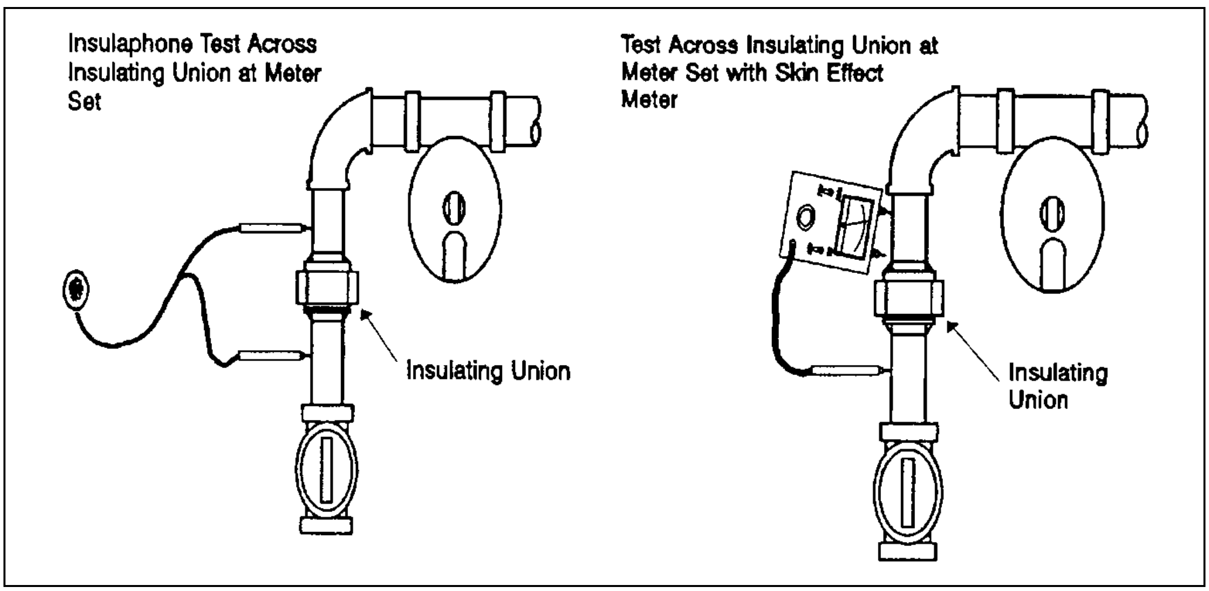

Figure 4: Above Grade Insulator Test

The insulaphone shown on the left is two probes connected to a phone type speaker. All buried pipelines have at least a small amount of A.C. impressed upon them (generally called noise). When the probes are connected across a good insulator, a buzz is heard. This is caused by the A.C. flow through the coils in the phone set. Conversely, if no buzz is heard, then the A.C. is flowing through the shorted insulator and not through the coils of the phone set.

The "skin" effect meter is a galvanometer type device which measures only the effects of the metallic structure between the two probe tips when adjusted correctly. It normally has two probes mounted on the instrument and one that can be hand manipulated to reach across the space of about a foot. This device is invaluable when there are multiple insulators in close proximity to each other. The insulaphone will not work in this situation if one insulator is shorted. The "skin" effect meter can be used to detect bad insulating gaskets or shorted bolting insulators in flanges independently of each other. An alternative to the “skin” effect meter is a voltmeter.

5.1.3 Current Flow Measurements

Current flow measurements would typically be completed by corrosion personnel to verify continuity or isolation on buried insulators if the above tests indicate that the insulator is not working properly. Measuring the actual current flow on a structure is a more accurate and valid method of determining the effectiveness of any below grade insulator. If measured current values exceed normal limits, they directly indicate a problem with an insulator or within the span drop. No single method should be used to draw a definite conclusion as to any problem or malfunction. Rather, a series of tests should be made before any conclusions are drawn. It is best to make some of these measurements as a routine test practice so that their values can be compared in any analysis. Refer to GS 1430.220 “Current Flow Measurements” for additional guidance.

5.2 Verifying Electrical Isolation on Metallic Casing/Carrier Installations

If shorts are suspected between metallic casing and metallic carrier pipeline installations, electrical isolation can be verified by utilizing at least two of the following methods listed below. The results should be evaluated together to make a judgment on the condition of the carrier pipeline to casing isolation.

a. Fixed Half Cell Test - See Section 2 above.

b. Interruption Measurement - See Section 3 above.

c. Voltage Test - See Section 5.1.1 above.

d. Resistance Test – Measure the resistance between the pipe and the casing using a soil-resistivity meter (e.g., Vibroground, Nilsson). A measurement of less than 0.2 ohms may indicate a shorted condition. Refer to GS 1430.210 “Soil Resistivity Measurements” for the Four-Pin Test Method.

6. RECORDS

Verification results with respect to troubleshooting should be documented within the Company’s work management system.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	Alternating Current Voltage Gradient Survey and Pipeline Current Mapper	Standard Number: **GS 1430.310**
Supersedes: 05/01/2010		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Alternating Current Voltage Gradient (ACVG) surveys are used primarily for Pipeline Integrity purposes to provide an assessment of the overall quality of the pipeline coating and to identify coating defects. These surveys can also identify bond breaks, insulators, and the position of anodes.

An AC current is applied to the pipeline, and prioritized according to the magnitude and change of current attenuation. An ACVG survey can be used for pipelines under any type of magnetically transparent cover, such as paved areas or areas under water, even in congested areas where there may be contact with other metallic structures or interference. However, the data may not be reliable; so paved areas should be drilled to allow the equipment to have good contact with the soil.

Pipeline Current Mapper (PCM) is a tool that can locate, determine depth of cover, and obtain current measurement and current direction on a pipeline. A transmitting unit generates an extra low frequency (ELF) signal that is applied to the pipeline. A receiver (detector) is used to measure the attenuation of the signal, which gradually decreases as the distance increases from the transmitter location. The logarithmic rate of decline of the current provides an indication of the average condition of the pipe coating between two given points.

These tools are typically used together for Pipeline Integrity purposes. Data can be integrated with data from other types of surveys for further interpretation. When conducting assessments using more than one survey tool, the PCM shall be used prior to the other tools in order to have the pipeline centerline accurately located.

Company and/or contractor personnel conducting surveys shall be qualified for conducting ACVG and/or PCM surveys in accordance with this gas standard. Separate contractor procedures may be used as an alternative to Company procedures, with approval from local corrosion leadership.

Many PCM transmitters mimic or simulate DC signal, and therefore pipe-to-soil potential measurements will be affected by the transmitter output signal. Consequently, a close interval survey (CIS) cannot be performed simultaneously with ACVG.

HSE 4100.020 “Work Zone Protection” or equivalent Company safety procedures shall be followed when conducting ACVG and/or PCM surveys.

2. EQUIPMENT

The following equipment should be used to conduct an ACVG survey:

a. PCM transmitter, which applies an AC signal that simulates a special near DC signal to the pipeline, separate but similar to a possible existing DC current applied by an impressed current cathodic protection system;

b. PCM receiver, which can locate the unique signal transmitted onto the pipeline and provide measurements of depth, current strength, and current direction;

c. PCM Magfoot Attachment, if required by the PCM equipment manufacturer,

d. accessory “A” frame attachment,

e. soil contact probes with reservoirs sufficient to maintain low contact resistance throughout the duration of the survey (e.g., accessory “A” frame attachment) to pinpoint coating defects and isolation faults;

f. GPS / data logging equipment to record data within sub meter accuracy;

g. AC power inverter or generator with a minimum 800 watts output, or a power source equivalent to two12 volt batteries connected in series;

h. locating flags and/or paint; and

i. measurement wheel for accurate data integration.

3. PCM DATA COLLECTION PROCESS

Operate equipment according to manufacturer’s instructions.

Prior to operation, check the condition of the equipment and connecting wires, clips, and plugs to make sure that equipment is in working order. Check the battery indicator; if the unit indicates less than 50 % battery charge, the batteries should be replaced with new batteries. Make sure equipment settings are set to the lowest levels.

3.1 PCM Transmitter Connection and Grounding

Connect the PCM transmitter at a point of connection to the pipeline. A cathodic protection test station wire is commonly used to connect the signal generator output (white wire). The transmitter signal ground wire (green wire) must be grounded appropriately using an isolated, low-resistance ground. The grounding electrode should be placed perpendicular from the pipeline at minimum of 25 feet from the structure. The following may be used for the grounding electrode:

a. buried magnesium anodes,

b. driven copper rod, and/or

c. a foreign structure running perpendicular or in the opposite direction and not crossing the structure to be surveyed.

NOTE: A fence, an electrical company grounding system, or a foreign structure running parallel with the structure to be surveyed shall not be used for a grounding electrode.

The grounding connection for the PCM transmitter shall be checked for low impedance by observing the unit at start up. The voltage limit indicator, if applicable, will display a red LED light, if low enough impedance cannot be achieved. If low impedance on grounding can not be achieved, readjust connections, add more grounding electrodes, or relocate to a better grounding electrode. A resistance of no more than 20 ohms shall be achieved.

3.2 Power Source Connection and Grounding

The power source is connected using the red (positive) and black (negative) wires. All connections shall be made with the connector cables supplied by the manufacturer. Grounding electrodes shall be connected to the power source. A power inverter connected to a vehicle shall be connected to the vehicle chassis.

Turn on power to the signal generator and adjust the output to the lowest setting possible that will provide good data without exceeding the voltage limit. The indication that the voltage limit has been exceeded is when the red LED on the front panel begin to light.

During the survey, the gain level should be evaluated. If the gain level goes above 75% and the signal power level is below 50%, then relocation of the unit may be necessary. Consistent output shall be maintained during testing.

3.3 PCM Receiver

Connect the antennae array to the PCM receiver and turn the receiver on. Verify that the receiver is operating properly by testing all functions over the pipeline before beginning survey.

The locate function operates in two modes, peak and null. The centerline of the pipeline must be verified in both locate modes. If the readings are more than 8 inches off, there may be a parallel short or the grounding mechanism is being influenced. Current measurements should be made in the peak mode directly over the centerline of the pipeline.

3.4 Survey Limitations

Difficulties may be encountered when adjacent metallic buried facilities distort the electromagnetic signal. Surveying multiple electrically continuous pipelines may also cause such distortion because of the overlapping electromagnetic fields of the parallel pipelines. The degree of this distortion will depend on the type and location of electrical interconnections at rectifiers, crossovers, and pipeline stations. Distortion of the signal may also occur at pipe tees, and pipe to anode connections. Because of this, it is best to disconnect sacrificial anodes and bonds to other structures, where possible, to prevent signal loss and enhance current flow down the pipeline.

Also, readings taken within high power AC corridors may also be distorted.

The PCM shall not be used over heavy gravel areas or wood mulch/chips. The ACVG shall not be used over paved areas, unless the equipment can make good contact with the soil.

4. INTERVALS

The centerline of the pipe should be located at 25 – 100 ft. intervals and at all pipeline bends or direction changes. GPS coordinates should be noted for all flagged or painted locations. PCM current attenuation signal strength and pipe depth measurements shall be taken at the same locations as the close interval survey and other tools used.

4.1 Pinpointing Coating Defects or Isolation Faults

When the PCM is being used with the bridge for ACVG surveys, the interval between readings should be reduced to the width of the “A” Frame.

5. ACVG FAULT FINDING

In locations where anomalies are identified based on the original PCM process in conjunction with close interval survey (CIS) data, the “A” Frame is used for precise locating of coating faults.

Operate equipment according to manufacturer’s instructions.

Prior to operation, check the condition of the equipment and connecting wires, clips, and plugs to make sure that equipment is in working order. Check the battery indicator; if the unit indicates less than 50 % battery charge, the batteries should be replaced with new batteries. Make sure equipment settings are set to the lowest levels.

5.1 Equipment Connections

Connect the “A” Frame to the PCM according to manufacturer’s instructions. Adjust the PCM Receiver accordingly.

5.2 Locate the Pipeline

Use the peak and null setting to confirm pipeline location.

5.3 Create a Test Fault Prior to Survey

To verify signal strength, created a temporary fault, at the test station at the end of the section being surveyed, with a short length of wire (or bare copper rod) in contact with the earth. Ensure that the fault is detectable by the receiver by performing a short (e.g., 30 feet) survey centered on the wire (or bare copper rod), and a survey off to the side by the same distance as the depth of cover over the pipe. The minimum reading should be 50 dB μV (decibel microvolts).

5.4 Fault Finding

Position the “A” Frame at a location above and in-line with the pipeline. Push the spikes into the ground to take a reading. Ensure that there is good contact with the soil; contact with pavement or wood chips will provide false readings.

Record the reading (dB microvolt), along with the direction of the reading. When the direction of the reading indicates a change in direction, the operator has passed over a coating fault.

5.5 Pinpointing Faults

When a fault is identified from a change in direction of the readings, pass back over the pipeline taking readings at approximately three (3) ft. intervals. Continue testing by taking measurements at smaller intervals, forwards or backwards, until the position is found where the change in direction occurs and the reading is the lowest. At this point, the fault is directly under the center of the “A” Frame.

Turn the “A” Frame 90 degrees so that it is now across (or perpendicular to) the pipeline. Repeat the previous stage of taking measurements until the change in direction occurs and the reading is the lowest. At this point, the fault is exactly under the center of the “A” Frame.

Record maximum decibel reading.

Mark the fault location with a stake or paint, GPS readings, or equivalent method.

6. CALIBRATION

Follow the manufacturer’s recommendations for calibration.

7. PRIORITIZATION AND REMEDIATION

For Company transmission lines, prioritize and remediate based on IMP 6-14 “External Corrosion Direct Assessment Plan.”

For distribution pipelines, prioritize and remediate based on discussions with local corrosion leadership.

8. RECORDS

For measurements related to Pipeline Integrity, records (e.g, location of ACVG indications, graphs, severity) shall be kept in the Pipeline Integrity database and/or files for the life of the pipeline. For measurements not related to Pipeline Integrity, records should be kept for reference for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Ultrasonic Thickness Gauge	Standard Number: GS 1430.320
Supersedes: 07/01/2013		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The ultrasonic thickness gauge (UTG) is a non-destructive tool that measures the metallic wall thickness of a pipeline or structure. The measurement can be compared to records identifying the original thickness to determine if wall loss has occurred internally or externally to the pipeline.

The UTG is also used to measure the remaining wall thickness of anomalies identified on the pipeline.

The UTG works by very precisely measuring how long it takes for a sound pulse that has been generated by a probe called an ultrasonic transducer to travel through a test material. The transit time of the sound pulse is used to calculate the thickness of the test material. In our case, the test material will typically be a pipe wall.

2. WALL THICKNESS MEASUREMENTS TAKEN FOR CORROSION ASSESSMENT

The guidance below pertains to taking wall thickness measurements for corrosion assessments. It is not intended for wall thickness measurements taken for strictly welding operations.

If the pipe exposure involves a transmission pipeline, refer to the Company's Transmission Integrity Management Program (TIMP) written plan or corrosion leadership for instructions on the locations in which to take UTG measurements and the Company form, if applicable, in which to document the results.

Corrosion leadership will review the UTG measurements to identify any potential inner or mid-wall pipe defects and for conformance to the known/assumed nominal wall thickness. Indications of anomalous measurements may be scheduled for repair or further investigation using higher resolution techniques. For this reason, it may be beneficial for corrosion leadership to be promptly notified when questionable readings are discovered, to take advantage of access to the exposed pipe. Examples of observations where corrosion leadership should be promptly notified include:

a. Measurements taken on the same joint continue to vary by more than 10% even after repeated measurements are attempted.

b. **If the pipe grade and nominal wall thickness are known by the technician** and the wall thickness measurements are less than the following:

Pipe Size	Grade B or Lower	Grade X42 or Higher
< 20 inches	nominal WT x 0.875	nominal WT x 0.875
≥ 20 inches	nominal WT x 0.875	nominal WT x 0.92

3. ULTRASONIC THICKNESS GAUGE (UTG)

Operate the UTG in accordance with the manufacturer's instructions. General guidance is indicated below.

3.1 Surface Conditions

UTG measurements are affected by the conditions, roughness, contour of the surface to be tested, and possibly dual-coat applications.

Review manufacturer recommendations for the instrument's coating tolerance to determine if intact coating is required to be removed to obtain accurate measurements.

To optimize measurement results, the surface should be first cleaned of any foreign debris including dirt, oil, grease, corrosion products, and coating remnants (for coatings that are not intact). Depending on the amount of contamination, cleaning with a wire brush or grinder with a wire brush wheel may be necessary.

On rough surfaces, the use of a generous amount of couplant minimizes the surface effects and serves to protect against wear of the transducer, particularly when dragging the probe across a surface.

3.2 Taking Measurements on Pipe

The couplant must be applied to the surface to be tested when measuring to eliminate air gaps between the wear-face of the probe and the surface of the pipe. A single drop of couplant is sufficient when taking a spot measurement. A line of couplant is necessary when dragging the probe during SCAN mode.

When measuring the thickness of pipe walls, the proper placement of the transducer is important. Refer to the manufacturer's recommendations for specific instructions regarding probe placement and direction.

A UTG measurement should be repeated if the reading varies by more than 10% from any other measurement taken on the same joint.

3.2.1 Scan Mode

Scan mode may be used for determining possible internal corrosion or anomalies by dragging the instrument along the circumference of the pipe. Typically, the instrument will display and record an average value or minimum and maximum values taken by a scan.

Measurements indicating internal defects shall be plotted with location references to document for subsequent identification.

NOTE: Do not use UTG directly in a defective area, including a gouge, scrape, or corrosion area.

3.3 Calibration

Calibrate each time before use or series of measurements. Follow manufacturer instructions for calibration.

4. RECORDS

Records showing wall thickness measurements of transmission pipelines, with the exception of measurements taken strictly for welding operations, shall be kept for the life of the pipeline.

For measurements investigating possible internal corrosion on transmission or distribution pipelines, records shall be kept in local corrosion files (e.g., circuit pack) or Integrity Management files, as appropriate, for the life of the pipeline.

For measurements not related to Pipeline Integrity or internal corrosion, records should be kept for reference for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**pH Testing Methods**	Standard Number: **GS 1430.322**
Supersedes: 03/01/2010		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

Measurement of the pH level of the soil or electrolyte surrounding the pipeline can help determine if the environment is corrosive. The total range of the pH scale is 0-14; where a value of 7 is neutral, less than 7 is more acidic, and higher than 7 is more basic or alkaline. The more acidic environment will result in a more corrosive electrolyte.

2. PIPELINE INTEGRITY MANAGEMENT PROGRAM ASSESSMENTS

The measurements of pH levels in the soil or electrolyte surrounding the pipeline or in liquid found underneath disbonded coating may be taken in conjunction with the direct examination step during an External Corrosion Direct Assessment (ECDA) for Pipeline Integrity purposes. The survey may be initiated based on the pipeline being exposed for validation, third party monitoring, third party damage, and/or anomaly identification. Data is collected and compared to the pre-assessment information for validation of accuracy.

3. PH MEASUREMENTS

Levels of pH in the soil or electrolyte surrounding the pipeline may be measured by using a direct-read soil pH meter, an antimony electrode, pH test strips, or another approved equivalent method.

3.1 Measuring pH with a Meter or Antimony Electrode

The meter shall be calibrated before each series of pH measurements. Follow manufacturer's instructions for calibration of the meter.

Operate the meter according to manufacturer's instructions.

Place the electrode(s) in the soil or electrolyte as close as practical to the surface of the pipeline to be tested.

Clean the electrode(s) to prevent contaminating the electrode surface and mistakes in accuracy of reading.

3.2 Measuring pH Using Test Strips

Test strips or papers may be appropriate to use when testing the pH of water found under disbonded coating.

Test strips or papers can be used for a rough estimation of pH. Some test strips or papers have a wide range (e.g., 1-14) for measuring the pH level. Others can measure pH at a more narrow range (e.g., 3-6, 7-10).

One method to measure pH of water found under disbonded coating is to carefully slice the coating (if necessary) to a length to allow the test strip or paper to be slipped behind the coating. Press the coating against the test strip or paper to immerse it in the electrolyte for a certain minimum period of time identified by the manufacturer's instructions.

Typically, the test strip or paper is removed from the electrolyte, and the color is compared to the scale found on the box or within the manufacturer's instructions.

4. RECORDS

For measurements related to Pipeline Integrity, records shall be kept in the Pipeline Integrity database and/or files for the life of the pipeline. For measurements not related to Pipeline Integrity, records should be kept for reference for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Microbiologically Influenced Corrosion**	Standard Number: **GS 1430.324**
Supersedes: N/A		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

Microbiologically Influenced Corrosion (MIC) is an aggressive type of localized corrosion caused by the presence or activities of microorganisms, including bacteria and fungi. An essential element of MIC is bacterial food, which is some form of decayed vegetable (organic) matter. Rope, rags, wood, roots, and other plant life are examples of bacterial food.

The purpose of this procedure is to provide guidelines for investigating possible MIC as a root cause of corrosion on a pipeline (e.g., investigating leak cause on a cathodically protected pipeline, External Corrosion Direct Assessment, Internal Corrosion Direct Assessment).

2. TYPES OF MIC

The following list includes the more common types of MIC.

a. Sulfur Reducing Bacteria (SRB)

b. Acid Producing Bacteria (APB)

c. Heterotrophic Aerobic Bacteria (HAB)

d. Iron Related Bacteria (IRB)

e. Slime Forming Bacteria (SLYM)

It has been established that the most aggressive MIC with natural gas pipelines are SRB and APB. MIC does not always produce a unique form of a localized corrosion pattern, so MIC may result in pitting, crevice corrosion, under deposit corrosion, and selective dealloying, in addition to enhanced galvanic and erosion corrosion.

3. INDICATORS OF MIC

MIC is often found when a pipeline is buried in tightly packed damp or wet clay. When the pipeline is exposed, it is found covered with a white, pasty material that quickly turns light brown when exposed to air. A black, flaky substance may be present along with old pieces of rope, rag, leaves or wood in contact with the pipeline, or there may be an outline of one or more of these organic items impressed on the surface of the pipeline in a pattern of corrosion.

Indicators that MIC may be present include the following:

a. areas where cathodic protection currents require an increase to maintain cathodic protection,

b. disbondment of coating (resulting in trapped water and CP shielding),

c. colonization corrosion patterns on surface of pipeline,

d. a drop of diluted hydrochloric acid placed on corrosion product deposits will produce the odor of rotten eggs when sulfides are present, and/or

e. laboratory or field test of soil sample to determine the content of MIC in colony forming units per milliliter (cfu/ml) with approved field kits.

4. TESTING FOR MIC

The only sure way to know if anaerobic bacteria are present in the soil and responsible for this type of corrosion is to secure a soil or water sample from the immediate area. From this sample a bacterial culture is developed. Inspection of the bacterial culture will determine if the anaerobic bacteria are present in the soil.

Avoid contact with the soil, corrosion product, or film with hands or tools other than sterile equipment to prevent contamination.

4.1 Inspections and Measurements

4.1.1 Site Observations

The following measurements should be performed prior to or during the digging operation.

a. soil resistivity,

b. pipe-to-soil potential, and

c. pH tests of soil and under pipeline coating.

Note the characteristics of soil with respect to moisture (e.g., moist, dry, or wet) and type (e.g., silt, sand, gravel, rock, clay). Note the existence of organic matter (e.g., ropes, rags, wood, plants).

4.1.2 Corrosion Area

Note the characteristics of the corrosion products with respect to color (e.g., brown, black, white, gray), shape (e.g., deposit, nodule, film), texture (e.g., fine, coarse), and odor (e.g., sulfur).

Note the form of any visible corrosion, including shape, size, and depth of pits.

4.1.3 Coating Inspection

When the pipeline is exposed, note the coating type, condition, type of damage (e.g., disbondment, holidays, blistering, seam tenting, cracking, wrinkling, none), extent of damage (e.g., percentage of exposed area), and location (i.e., circumferential and longitudinal position on the pipe in relation to weld seams and coating seam, if present).

4.2 Sample Collections

Solid and liquid samples must be placed in clean, sterile, sealed, carefully labeled containers. The bag or tube must be sealed tightly, and the whole sample sealed again within a second plastic bag or all openings sealed with an air tight tape to reduce the risk of leakage. Follow sampling instructions provided by the manufacturer of the kit.

Because the analytical results can be affected by contamination and environmental conditions, collecting samples for microbiological analysis should be avoided when pipe and coating have been extensively handled, exposed to atmosphere or sunlight for extended periods of time, or otherwise exposed to conditions where dehydration, temperature changes, or contamination could occur. If such samples are analyzed, the compromising conditions should be documented so they may be taken into consideration when a final evaluation of the data at that site is performed.

Typically, the soil sample can be field tested for microbiological levels and type. Liquid and corrosion product samples should be collected for further analysis if soil sample results support evidence of MIC.

If collecting samples for laboratory testing, then samples need to be packaged, iced and sealed for delivery to the laboratory within 24 hours.

If collecting samples for field testing, then samples need to be kept in a cool, dry location, with temperatures in the range of 70 to 75 for incubation.

4.2.1 Liquid Sample

If a small volume of liquid is present under the coating, a sample should be taken using a sterile syringe or polyester-fiberfill swab. The liquid sample may be used for the testing to determine the existence of microorganisms contributing to MIC. The swab or liquid from the syringe must be stored in a sterile plastic tube until tested.

4.2.2 Corrosion Product Sample

If surface deposits or corrosion products are fragile, they should be scraped from the pipe. Corrosion products must be collected by scraping the area with a sterile scalpel or equivalent tool, or swabbing with a sterile polyester-fiberfill swab. The swab and/or products must be stored in a sterile plastic tube until tested.

4.2.3 Soil Sample

Collect undisturbed soil immediately next to the exposed pipe surface or at an area of coating damage. A clean spatula, or equivalent tool, should be used to collect the soil, so that it is not contaminated.

A second soil sample may be taken for reference at an undisturbed location at pipe depth at least three (3) feet transverse to the pipe. This location acts as a reference from which to determine whether the microbial population near the pipe is elevated.

Whenever possible, a clean working surface should be used, because if proper precautions are not taken, dust or dirt on the working surface or general area can potentially contaminate the inside of sample containers when a sterile sample bottle is uncapped. Ideally, the containers should be handled by gripping the lower part of the bottle and/or using sterile gloves (skin contact with the upper part of the container must be avoided).

Only sterile saline may be used with the soil samples for testing purpose for field kits or any material approved by the manufacturer. Follow the manufacturer's instructions of the test kit for taking the soil sample, performing the test and interpreting the results of the test.

4.3 Verifying MIC

MIC is verified when the following three conditions are met.

a. From soil and/or liquid sample: Demonstration of increased levels of specific types of viable microorganisms (bacteria or fungi) associated with the corrosion, relative to samples taken outside the corroded area. This is assuming there is no known or suspected contamination from outside sources (e.g., soil, groundwater).

b. From the corrosion product sample: Chemical indicators that support the microbiological evidence (e.g., elevated levels of sulfide or sulfur in pit deposits for SRB, organic acids for APB, etc.) are identified in the corroded area.

c. From site observation: Evidence of bacterial food (i.e., organic matter) contributing to the corrosion observed and influence of soil conditions, such as damp or wet, tightly packed clay.

5. NOTIFICATION

If MIC is confirmed on a transmission line, notify the personnel responsible for managing the Company's Integrity Management Program.

6. REMEDIATION

As part of the remediation design, a perimeter of the MIC influence, based on a series of testing, shall be established. A suggested best practice is to test soil near the pipeline at locations approximately 100 feet in each direction from the confirmed location. Consider different soil types that may change the chance for MIC presence (e.g., wet clay vs. sandy soils) when establishing the perimeter of MIC influence.

In addition to the remedial measures provided in GS 1460.010 "Corrosion Remedial Measures – Distribution" or GS 1460.020 "Corrosion Remedial Measures – Transmission Lines," the following actions may be taken to reduce the effects of microbiological bacteria:

a. the use of MIC inhibitors,

b. adding lime to soil in the affected area to raise the pH level of the surrounding soil,

c. raising the required levels of pipe-to-soil potentials above the currently used cathodic protection criterion (typically achieved at -950 mV CSE) and/or

d. if MIC is found internally, coupons may be installed for monitoring internal corrosion and effect of mitigation.

NOTE: If MIC inhibitors are considered, they must be evaluated and approved by the corrosion leadership.

7. RECORDS

Document the site inspection observations and measurements, the amount and type of bacteria measured by each test, and conclusions within the Company's work management system, local corrosion filing system, and/or equivalent.

Records of confirmed MIC on a transmission line shall be kept within the Transmission Integrity Management files and maintained for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Direct Current Voltage Gradient (DCVG) Survey**	Standard Number: **GS 1430.330**
Supersedes: 05/01/2010		Page 1 of 10

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Direct Current Voltage Gradient (DCVG) surveys are used primarily for Pipeline Integrity purposes to evaluate coating conditions on buried pipelines. When conducting a DCVG survey, the cathodic protection current is interrupted and voltage gradients are created in the proximity of the locations of coating defects along the pipeline. The voltage gradients at these locations are noted by a change in signal strength as measurements are taken along the pipeline. The coating defects can be pinpointed and their corresponding voltage gradients can be measured and recorded. The values from these surveys can then be integrated with data from other types of surveys to determine locations of possible corrosion. If the system being evaluated is not cathodically protected by an impressed current system, a portable DC generator or a portable rectifier may be required to create sufficient voltage shifts required to conduct these surveys.

If a close interval survey (CIS) is being performed in conjunction with the DCVG, the CIS should be performed first, so that the pipe-to-soil potential measurements are representative of "normal" conditions.

Company and/or contractor personnel conducting surveys shall be qualified for conducting DCVG surveys in accordance with this gas standard. Personnel shall be trained and familiar with the DCVG survey process.

HSE 4100.020 “Work Zone Protection” or equivalent Company safety procedures shall be followed when conducting a DCVG survey.

2. EQUIPMENT

The following equipment should be used to conduct a DCVG survey:

a. voltage measurement meter capable of measuring voltage gradients accurate to within 1 mV in both positive and negative directions,

b. existing cathodic protection current source *or* a portable generator and portable rectifier,

c. current interrupter(s) capable of being synchronized with a sufficiently high degree of accuracy (< 10mS deviation throughout survey),

d. soil contact probes with reservoirs sufficient to maintain low contact resistance throughout the duration of the survey,

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e. GPS / data logging equipment to record voltage gradient values and location to within sub meter accuracy,

f. locating flags and/or paint, and

g. pipeline current mapper or equivalent pipe locator.

Prior to beginning the survey, the contact probes should be checked and balanced so that the probes measure within 5 mV of each other.

3. VOLTAGE GRADIENT MEASUREMENTS

Before DCVG surveys are conducted on any pipeline segment, the centerline of the pipe should be located at intervals sufficient for the next marker to be visible from the previous marker (e.g., 25 - 100 ft. intervals) and at all pipeline bends or direction changes.

Check battery voltage and proper operation of test equipment. Ensure that all test leads, clips, connectors are insulated and are making good connections.

Ensure that current source(s) are energized and interrupters are working properly. Measure the voltage shift at the beginning and end of the pipeline segment to be tested. The current source may need to be increased so that the voltage shift is approximately 500 mV in order measure enough voltage shift to identify coating anomalies. If 500 mV shift cannot be achieved at the end of the survey segment, consider relocating the portable rectifier and ground bed to achieve approximately 500 mV shift. Due to soil resistivity or pipeline characteristics, a minimum of 200 mV shift is acceptable.

The optimum interruption cycle for conducting the DCVG survey is a cycle using an OFF cycle three times longer than the ON cycle if the DCVG survey is done as a stand-alone test. However, it is considered acceptable to use the same interruption cycle used during CIS surveys if these surveys are being conducted during the same time period, in order to reduce survey cost. The DCVG may have to progress at a slower rate than what would be optimum because a faster interruption cycle may make it difficult to see the voltage shifts.

DCVG measurements shall be taken at 2 ½ - 5 ft intervals along the pipeline. At least one probe shall be in contact with the soil at all times. There are two methods of taking DCVG measurements:

a. Sidestep method: One probe should be kept near the pipe centerline and the other placed forward and offset from the pipe.

b. Over-the-pipeline method: One probe is kept near the pipe centerline and the other is placed forward and near the pipe centerline.

The survey shall progress along the pipeline with the magnitude of the shift between the ON and OFF reading noted, along with the direction of the shift. Also, at each test station along the survey, note the magnitude and direction of the shift with one probe connected to the pipeline through the test station and the other probe in contact with the soil. The readings taken at each test station will determine the maximum shift (signal strength), which can be used for pinpointing a defect (see Section 3.1 below). Plus, readings taken at each test station provide verification of continuity or isolation. Any obstacle encountered that takes you off the centerline of the pipeline shall be noted in the survey data in order aid in interpretation of the data.

When concrete pavement is encountered, thoroughly wet the surface of the pavement and use a surface probe with a larger surface area in order to obtain as accurate measurements as possible. If accurate measurements cannot be obtained by wetting, holes large enough for the probe to penetrate to the soil shall be drilled along the pipeline. Water shall be poured into the holes and the reference probe inserted. The holes shall be plugged and patched after completion of the survey. If asphalt pavement is encountered, then holes must be drilled. No roadways shall be drilled without appropriate permits and traffic controls in place

3.1 Locating and Pinpointing Coating Defects

As a coating defect is approached, a noticeable swing is observed at the same rate as the interruptions, and the swing reverses after the defect is passed.

When a coating defect is located, the approximate location shall be marked, then the epicenter shall be pinpointed by finding the null location in the gradients along both sides of the pipeline. The epicenter of the location shall be marked. The mV gradient measurement (maximum voltage shift) shall be recorded between the ON and OFF cycles, along with the direction of the shifts. The GPS coordinates of the coating defect epicenter should also be recorded.

Once the DCVG anomaly has been pinpointed, the voltage gradient shall be measured and recorded with a lateral measurement perpendicular to the pipeline in line with the holiday in order to record the majority of the full over-the-line to remote earth voltage gradient at that location (see Figure 1 below). The direction of the voltage gradient shall be noted in the current OFF condition and the current ON condition. Measurements shall be taken until a deflection of less than 1 mV is measured. The summation of the voltage gradients is called the “over-the-line to remote earth” voltage.

To further define the location of the anomaly (e.g., top, north side, west side), additional measurements may be taken in a circle around the anomaly at specific angles (e.g., 45°). As greater magnitudes of voltage gradients are measured, the more accurate the anomaly is pinpointed. See Exhibit A for examples of voltage gradient measurement plots for coating defects at different locations on the pipeline.

NOTE: Galvanic anodes and other metallic appurtenances (i.e., service taps) can show up as DCVG indications. If an indication appears to be "off line", this should be noted in the comments in order to help with indication classification.

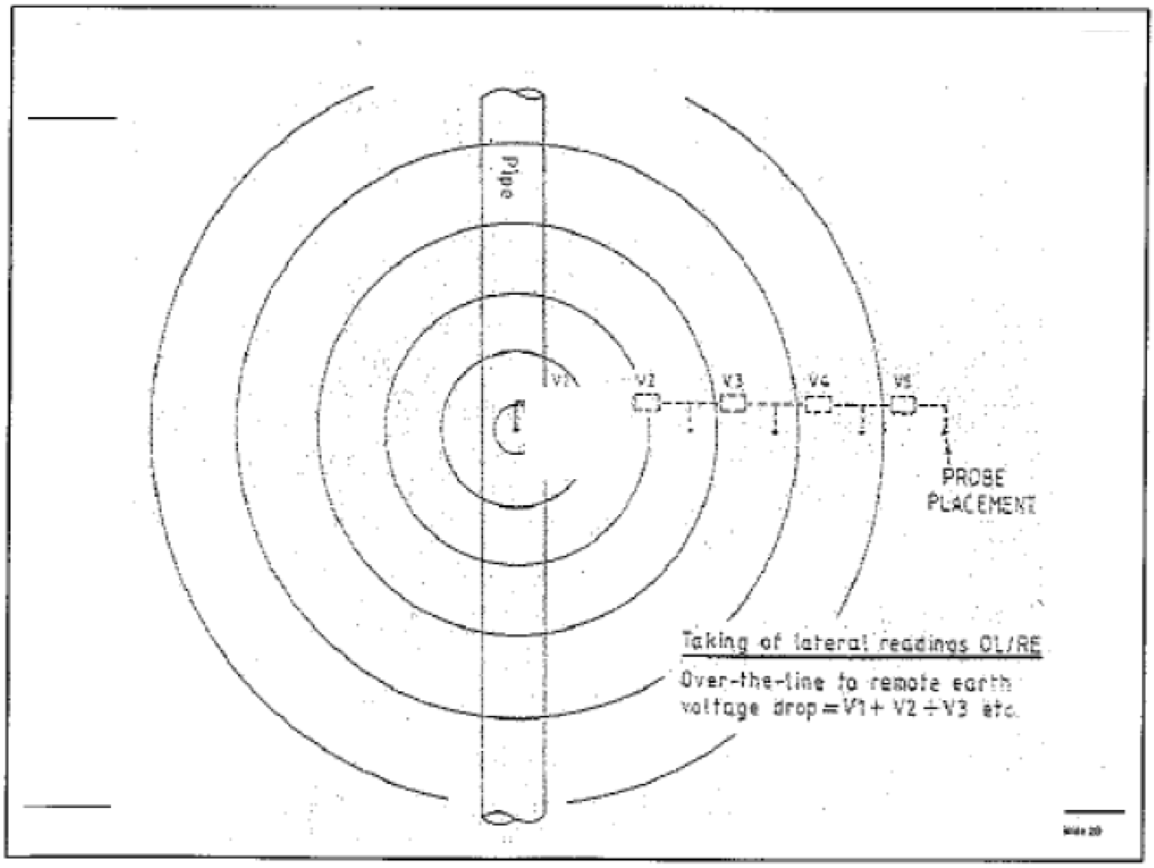

Figure 1: Lateral Measurements for Full Over-the-Line to Remote Earth Voltage Gradient

3.2 Determining Signal Strength at Anomaly (ΔV)

Measure the signal strength at each test point before and after the anomaly. Calculate the signal strength (i.e., voltage shift or ΔV) at the anomaly assuming straight line attenuation.

$$\Delta V_h = \Delta V_A + \left(\frac{D_{Ah}}{D_{AB}}\right)(\Delta V_B - \Delta V_A)$$

Where, ΔV_h = voltage shift (signal strength) between "ON" and "OFF" cycles at holiday

ΔV_A = voltage shift between "ON" and "OFF" cycles at Test Point A

ΔV_B = voltage shift between "ON" and "OFF" cylces at Test Point B

D_{Ah} = distance between Test Point A and holiday location

D_{AB} = distance between Test Point A and Test Point B

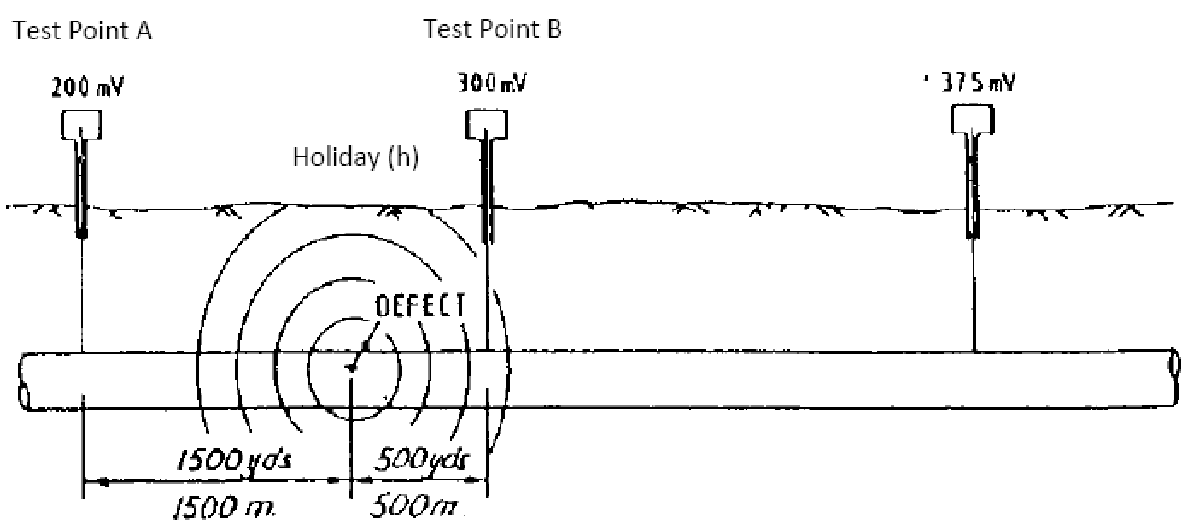

Figure 2: DCVG Survey – Calculation of Voltage Shift at Holiday

From the example shown in Figure 2, the voltage shift at the holiday (**ΔV_h**) can be calculated as follows.

$$\Delta V_h = 200\text{mV} + (1500/2000)(300\text{-}200)\text{mV} = 200\text{mV} + 75\text{mV} = 275\text{mV}$$

3.3 Determining Percentage of IR Drop

The magnitude of the voltage gradient itself may not indicate the size of the coating anomaly. However, the defect can be sized by measuring the %IR drop at each anomaly found to obtain a *relative idea* of the size or severity of the coating defect.

The %IR drop can be calculated as the ratio between the over-the-pipeline to remote earth voltage drop and the voltage shift at the defect location.

$$\%IR = \frac{\Delta G_{P-1} + \Delta G_{1-2} + \Delta G_{2-3} + \Delta G_{3-X} + \Delta G_{X-Y}}{\Delta V} \times 100\%$$

Where, ΔG_{P-1} = difference in voltage gradient readings from the pipeline to point 1;

ΔG_{1-2} = difference in voltage gradient readings from point 1 to point 2;

ΔG_{2-3} = difference in voltage gradient readings from point 2 to point 3;

ΔG_{3-X} = difference in voltage gradient readings from point 3 to point X, where X is the next point where the probe is placed;

ΔG_{X-Y} = difference in voltage gradient readings from point X to point Y, continuing on until where Y is the point where the difference in voltage gradient readings is 1 mV or less; and

ΔV = voltage shift between "ON" and "OFF" cycles (signal strength) at holiday (see Section 3.2).

Other methods to calculate %IR drop shall be reviewed and approved by local corrosion leadership.

Depth of the pipeline also influences the readings. A typical pipeline buried at 3-5 feet deep with a 20-30% IR drop may represent a coating defect of approximately 2 square inches.

4. CATEGORIZATION OF ANOMALIES

If the survey is being completed as part of a Pipeline Integrity assessment, the results shall be categorized for severity according to the Company's IMP 6-14 ""External Corrosion Direct Assessment Plan" Exhibit D. If specific guidance is not available in IMP 6-14, use Table 1 below, which is commonly used to categorize the severity of anomalies found during DCVG surveys.

Table 1

Category	%IR Drop
1 – No Indication (NI)	< 1
2 - Minor	1-15

3 - Moderate	16-35
4 - Severe	36-100

In addition, for Company transmission lines, the frequency of categories identified above found within 100 feet shall be further categorized based on IMP 6-14 "External Corrosion Direct Assessment Plan" Exhibit D.

5. PRIORITIZATION AND REMEDIATION

For Company transmission lines, prioritize and remediate based on IMP 6-14 "External Corrosion Direct Assessment Plan."

For distribution pipelines, prioritize and remediate based on discussions with local corrosion leadership.

6. RECORDS

For measurements related to Pipeline Integrity, records (e.g., location of anomaly, voltage shift, %IR, and severity) shall be kept in the Pipeline Integrity database and/or files for the life of the pipeline. For measurements not related to Pipeline Integrity, records should be kept for reference for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

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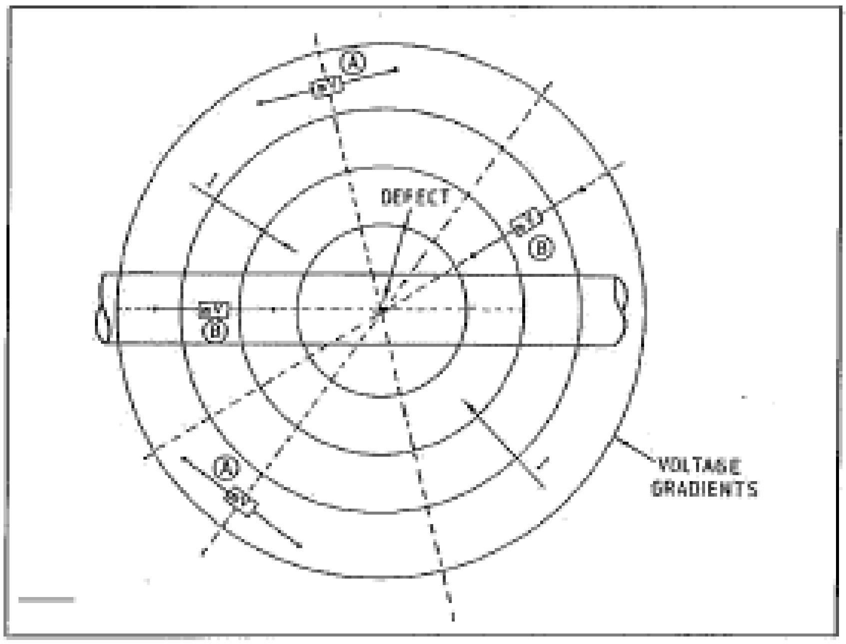
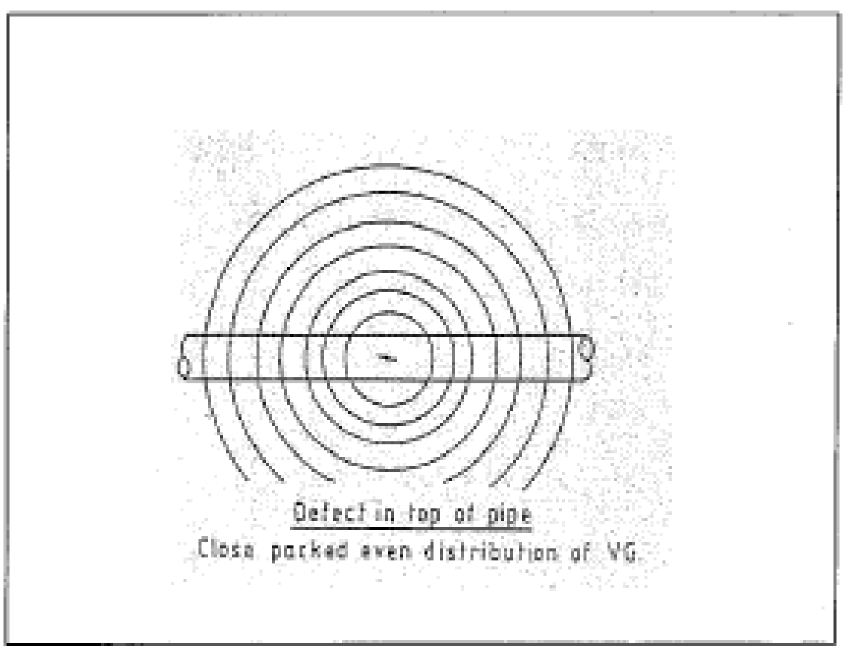
Supersedes: 05/01/2010		Page 8 of 10

EXHIBIT A
(1 OF 3)





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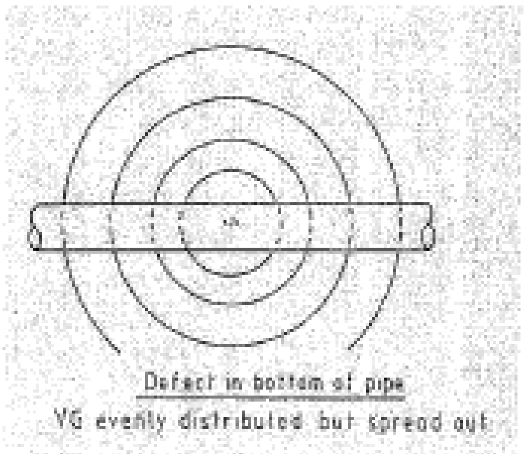
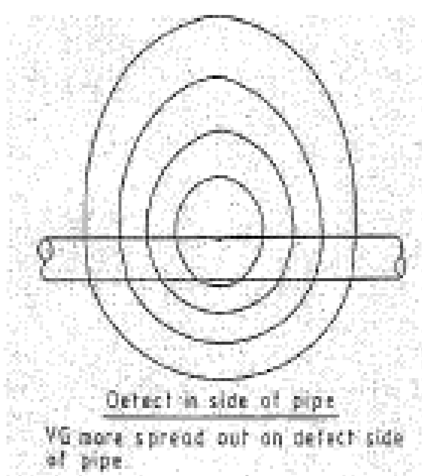
(2 of 3)





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Gas Standard

Effective Date: 12/31/2012	**Direct Current Voltage Gradient (DCVG) Survey**	Standard Number: **GS 1430.330**
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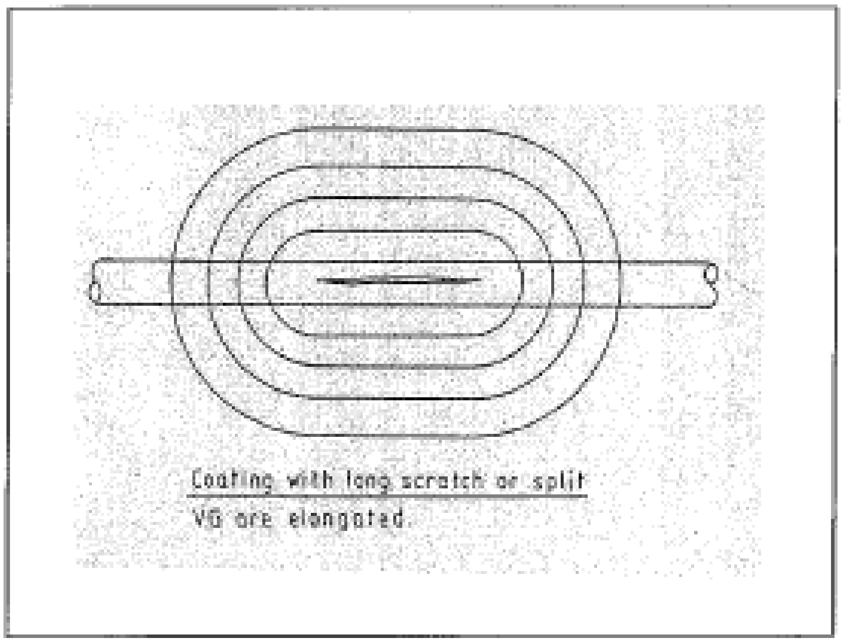
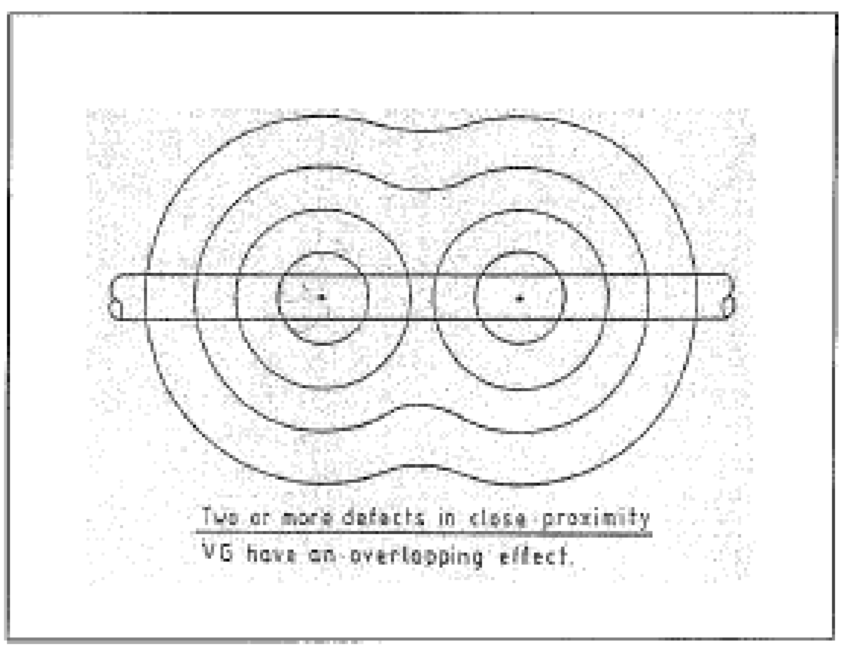
(3 of 3)





NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Cathodic Protection Troubleshooting Methods**	Standard Number: **GS 1430.410**
Supersedes: 05/01/2010		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

Troubleshooting is required when cathodic protection systems are not operating properly. A system is considered to be operating properly when it meets one of the criteria set forth in GS 1420.020 “Criteria for Cathodic Protection.”

This standard must be considered as a guide since cathodic protection systems do not always react the same way in similar situations. Field conditions will dictate the sequence and intensity of the various investigations that may be required.

2. GALVANIC ANODE CATHODIC PROTECTION SYSTEM

When anode systems do not meet the established criteria, the cause is generally attributable to four primary reasons:

a. unwanted insulation,

b. electrical shorts,

c. inadequate or damaged coating, and/or

d. insufficient current (e.g., depleted anodes).

Although this is an over-simplification of several complex problems that may be present, these are the four most frequent reasons designed magnesium anode protected pipelines become unprotected.

The first step in troubleshooting a defective anode system should be to determine if shorts exist. Due to the complexity of a distribution system, the possibility of electrical shorts always exists.

Electrical shorts may result from a variety of causes, such as the failure or lack of insulation at a meter, shorted vent line at an insulated meter, the pipeline touching a foreign underground metal structure, or a shorted insulator at a tie-in. If several electrical shorts exist on the piping system, they may have to be located and corrected one at a time. Several attempts may be required to find all electrical shorts.

If the anode system is not operating properly after all electrical shorts have been found and corrected, the probable cause is insufficient current being applied to the pipeline. The deficiency of current may be caused by insufficient anodes, bare or poorly coated pipe, depleted anodes, broken anode leads or gathering wires, etc. Common reasons for insufficient current are bare or poorly coated company and customer service lines. In order to correct this condition, it may be necessary to install additional anodes. It is recommended that a current requirement test (GS 1430.230 “Current Requirement Test”) be conducted to determine the additional quantity of current required.

If investigation shows that some sections of the pipeline are protected and some are not, the probable cause is that the piping system is not electrically continuous. Unknown insulators or high resistance joints should be located (refer to GS 1430.250 “Verifying Electrical Continuity and Isolation”) and documented. After locating these points of insulation, they may be bonded to make one electrically continuous pipeline or they may be left unbonded and anodes and test stations installed on the unprotected sections thus establishing separate smaller cathodically protected systems.

3. IMPRESSED CURRENT CATHODIC PROTECTION SYSTEM

When impressed current systems do not meet the established criteria, the cause is generally attributable to three primary reasons:

a. rectifier or groundbed failure,

b. electrical shorts, and/or

c. unwanted insulation.

Although this is an over-simplification of several complex problems that may be present, these are the three most frequent reasons designed impressed current cathodically protected pipelines become unprotected.

The first step in troubleshooting a defective impressed current system should be to check the rectifier and ground bed to see if they are operating as designed. If the rectifier and ground bed are not producing the designed output current, the rectifier must be checked out. When an appropriate size resistor is connected between the output terminals of the rectifier, and the designed voltage and amperage is produced, the rectifier unit is not at fault. Care should be taken to ensure that the resistor has sufficient current carrying capacity. The meters in the rectifier should not be used for this test. When the rectifier does not produce its designed output voltage and amperage, one or a combination of several problems may exist. Exhibit A describes how a rectifier might behave, the possible problems, and suggestions on how to prove or find the problem.

If the rectifier unit is operating as designed, but the current output of the rectifier and ground bed does not meet design, the problem may be in the ground bed. The ground bed design should be examined to see if it is adequate. If the ground bed will not produce current at any voltage, the gathering wire or pipe-to-rectifier connection is broken.

If the ground bed will not produce design current, the problem may be attributable to depleted anodes, an increase in soil resistivity because of weather conditions, dried out backfill and soil around the anodes, failure of lead or gathering wire, gas formation around the anode, etc.

These problems can frequently be found and corrected in a concentrated or distributed ground bed. However, most of these problems are impossible to find and correct in a deep anode ground bed. As a result, problems with a deep anode ground bed may require replacement of the anodes and backfill.

If the rectifier and ground bed are operating properly, the second step should be to determine if shorts exist.

Electrical shorts may result from the failure or lack of insulation at a meter, vent line shorting an insulated meter, service or main line touching a foreign underground metal structure, shorted insulator at a tie-in, etc. Electrical shorts must be located (refer to GS 1430.250 “Verifying Electrical Continuity and Isolation”). If several electrical shorts exist on the piping system, they may have to be found and corrected one at a time.

If investigation shows that some sections of the pipeline are protected and some are not, the probable cause is that the piping system is not electrically continuous or that there are high resistance joints in the piping system.

It is recommended that insulators be bonded through a test station. This practice will make it possible for the piping system to be sectionalized for test purposes by disconnecting the bond in the test station or by installing resistance control bonds. It may be helpful to work with a smaller section to locate and correct problems of the system.

When the impressed current system does not operate properly after the ground bed has been checked out and shorts, insulators and high resistance joints have been corrected, the problem probably is a deficiency of current. A current requirement test should be conducted to determine additional current requirements.

Supplemental current may be supplied by increasing the rectifier output, by additional impressed current systems, by magnesium anodes, and/or by upgrading the existing rectifier and ground bed installation. If it is impractical to provide additional current, a smaller piping system must be established by isolating pipeline sections from the system. This sectionalizing should only be done with great care, because it requires interference testing at the insulators and may involve the installation of resistance control bonds across the insulators to prevent stray current corrosion.

4. REMEDIATION

Refer to GS 1430.020 “External Corrosion Control Monitoring” for remediation timeframe requirements.

5. RECORDS

Troubleshooting results should be documented within the Company's work management system.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Cathodic Protection Troubleshooting Methods**	Standard Number: **GS 1430.410**
Supersedes: 05/01/2010		Page 5 of 6

EXHIBIT A
(1 OF 2)

RECTIFIER BEHAVIOR	POSSIBLE PROBLEM	PROOF OF OR HOW TO FIND PROBLEM
No current or voltage.	Blown fuses or circuit breakers.	Examine fuses or circuit breaker. Check AC voltage at the output. Check rectifying elements for possible short. Check lightening arrestors (DC and AC) for a possible closed circuit. Check all surge protection devices for possible closed circuit. Check transformer for possible short with the Ohms test across the coarse and fine, and across the secondary and primer windings. Check breaker unit for possible short.
	No power to rectifier.	Check AC line voltage at input fuses or circuit breaker.
	Electrical circuit in open status in rectifier.	Check for presence of AC voltage starting at the inlet and outlet terminals of the fuses or circuit breaker. Check for presence of AC voltage input and DC voltage output at the terminals of the rectifying elements. The open circuit is located between the last place AC or DC voltage was detected and the first place AC or DC voltage was not detected.
Tests indicate rectifier operating, but rectifier meters will not indicate voltage or current.	Meters defective or connected incorrectly.	Check wiring and/or test meter in rectifier.

EXHIBIT A
(Page 2 of 2)

RECTIFIER BEHAVIOR	POSSIBLE PROBLEM	PROOF OF OR HOW TO FIND PROBLEM
Rectifier operating at half rated DC voltage.	Rectifier connected to improper power source.	Check AC voltage to rectifier to make sure the input voltage is correct.
	Open rectifying elements	Perform voltage drop test forward and reverse across the four rectifying elements individually. If no voltage drop exist in both directions on the same element then this is an indication of a open rectifying element.
Rectifier will not operate at rated voltage and current	Badly aged rectifying elements	Conduct forward and reverse voltage drop tests across all rectifying elements individually. Check efficiency of the rectifier and compare to original efficiency.
	Low line voltage	Check input AC voltage to rectifier.
	Bad connection on transformer coarse and fine tap settings.	Check AC output of the transformer.
Rectifier will operate at only selected settings	Breaks in secondary transformer or taps	Check the AC voltage on the coarse and fine taps that are the selected settings. Check for corrosion film on tap settings.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Internal Corrosion Inspection Requirements**	Standard Number: **GS 1440.010(KY)**
Supersedes: 01/01/2014		Page 1 of 4

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.475, 192.476, 192.491, 192.709; KY 807 KAR 5:006 Section 26(3)

1. GENERAL

Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

When a new or replacement transmission line is being designed, the risk of internal corrosion shall be considered. Refer to GS 1420.110 “Internal Corrosion Design Guidelines for Transmission Lines.”

Typically, the gas delivered to the Company is considered non-corrosive. However, in consideration of accepting alternative gas sources (e.g., landfills, dairy farms) into the Company’s piping systems, a design to reduce the risk of internal corrosion, as well as the need for internal corrosion monitoring devices, must also be considered. Refer to GS 2910.020 “Alternate Gas Sources - Evaluation and Requirements.”

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion.

This gas standard applies to both metallic distribution and transmission lines. For transmission lines, refer to IMP 6-15 “Internal Corrosion Direct Assessment Plan” for guidance regarding Pipeline Integrity Management assessment requirements.

2. PIPELINE INSPECTION REQUIREMENTS

Whenever any active metallic **pipe** is removed from a pipeline for any reason, the internal surface shall be visually inspected for evidence of internal corrosion by a qualified person, as defined in GS 1400.010 “Corrosion Control - General.” Metallic **pipe** removed from a pipeline includes a cylindrical piece of pipe removed from a transmission line, main, service line, or a meter setting. Tap coupons or meters that are removed from a pipeline are not considered to be a cylindrical piece of pipe.

If evidence of internal corrosion is found, notify the appropriate personnel per Section 3 below.

Report findings according to GS 1410.010 “Metallic Pipeline Exposures.”

2.1 Tap Coupons

Whenever a pipeline is tapped and the tap coupon is removed, the tap coupon should be examined for evidence of internal corrosion. If evidence of internal corrosion is found, the results of the examination shall be recorded according to GS 1410.010 “Metallic Pipeline Exposures.”

3. NOTIFICATION REQUIREMENTS

If evidence of internal corrosion is found, promptly notify local corrosion personnel. If evidence of internal corrosion is found on a Company owned transmission line, the local corrosion personnel shall promptly notify the personnel responsible for managing the Company’s Integrity Management Program.

4. INVESTIGATION AND MITIGATION MEASURES

The local corrosion front line leader/supervisor, or a designated person qualified in corrosion control, shall initiate an investigation to determine the cause and corrective action necessary to mitigate any further internal corrosion.

If evidence of internal corrosion is found, the adjacent pipe shall be investigated to determine the extent of internal corrosion.

4.1 Investigation Guidance

Investigation actions may include, but are not limited, to the following actions.

a. Establish the perimeter of internal corrosion.

b. Determine the source of moisture and/or pipeline liquids by evaluating data from gas composition, moisture analyzer, and/or liquid analysis.

c. Contact the supplier for information on upsets that may affect gas quality. Refer to GS 2910.010 “Gas Supply – Gas Quality Specifications.”

d. Utilize, if available, laboratory testing to determine the source of corrosion. If deposits are found, they should be collected and analyzed. Refer to GS 1440.020 “Internal Corrosion Monitoring” for a list of corrosive constituents that should be included in the analysis.

e. Utilize, if available, an ultrasonic test gauge (UTG) or in-line inspection (ILI) device to identify other possible internal corrosion issues/locations. Refer to GS 1430.320 “Ultrasonic Thickness Gauge” and/or IMP 6-11 “Inline Inspection and Analysis” for additional guidance.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Internal Corrosion Inspection Requirements**	Standard Number: **GS 1440.010(KY)**
Supersedes: 01/01/2014		Page 3 of 4

f. Consider the installation of internal corrosion monitoring device(s). Refer to GS 1440.020 “Internal Corrosion Monitoring” for additional guidance.

4.2 Mitigation Measures

Mitigation or corrective actions may include, but are not limited to, the following actions:

a. Remove liquids or solids by:

1. pigging (refer to GS 3000.500 “Internal Cleaning of Pipelines”);
2. installing, operating, and/or maintaining drip(s); and/or
3. installing, operating, and/or maintaining filter(s)/separator(s).

NOTE: When corrosive liquids and/or solids are found on a frequent basis in the same general vicinity of a piping system, a frequency should be established for maintaining drips and/or separators and/or for conducting pigging operations. Refer to GS 1440.020 “Internal Corrosion Monitoring” for sampling guidance.

b. Consider chemical or biological treatments. These treatments shall not cause deterioration of piping system components and shall be compatible with the gas and piping system. Consult with a treatment supplier to determine treatment options for a pipeline system.

c. Repair or replacement of pipeline found with internal corrosion shall be made as required by GS 1460.010 “Corrosion Remedial Measures - Distribution” and GS 1460.020 “Corrosion Remedial Measures – Transmission.”

5. RECORDS

Results from required inspections, whether internal corrosion is or is not found, shall be recorded according to GS 1410.010 “Metallic Pipeline Exposures.” The date and time of the internal corrosion inspection shall be recorded in the electronic WMS Job Order execution remarks field.

The results of the investigation shall also be retained and may include information such as:

a. corrosion characteristics (e.g., generalized, localized),

b. wall loss measurements,

c. location with respect to the horizontal at the corroded section and with respect to the elevation of adjacent sections,

d. existence of deposits and evidence of corrosion under the deposits,

e. extent of internal corrosion found,

f. root cause determination, and

g. mitigation or remediation recommendation.

These records shall be retained for the life of the pipeline within the Company's work management system, or equivalent. For internal corrosion found in transmission lines, records shall also be kept in the Pipeline Integrity Management files.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Internal Corrosion Monitoring**	Standard Number: **GS 1440.020**
Supersedes: 12/31/2012		Page 1 of 7

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.475, 192.477, 192.491, 192.709

1. GENERAL

Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

When a new or replacement transmission line is being designed, the risk of internal corrosion shall be considered. Refer to GS 1420.110 "Internal Corrosion Design Guidelines for Transmission Lines."

Typically, the gas delivered to the Company is considered non-corrosive. However, in consideration of accepting alternative gas sources (e.g., landfills, dairy farms) into the Company's piping systems, a design to reduce the risk of internal corrosion, as well as the need for internal corrosion monitoring devices, must also be considered. Refer to GS 2910.020 "Alternate Gas Sources - Evaluation and Requirements."

2. PIPELINE INTEGRITY MANAGEMENT PROGRAM ASSESSMENTS

Assessments for internal corrosion will be conducted in conjunction with Pipeline Integrity Management activities in High Consequence Areas (HCAs) whenever internal corrosion is shown to be a threat. Refer to IMP 6-15 "Internal Corrosion Direct Assessment Plan" for additional guidance.

3. INTERNAL CORROSION MONITORING METHODS

Provisions for internal corrosion monitoring shall be implemented if:

a. corrosive gas is being transported in distribution or Company owned transmission lines,

b. whenever inspections or assessments identify internal corrosion as a potential threat on a Company owned transmission line, or

c. where corrosive liquid is likely to collect in a new or replaced Company owned transmission line or on the existing transmission line downstream of a change in the configuration of a Company owned transmission line, and the liquid removal system is not provided or does not effectively remove liquid water and there is significant potential for internal corrosion. Refer to GS 1420.110 “Internal Corrosion Design Guidelines for Transmission Lines.”

Several types of internal corrosion monitoring methods are listed below. The list includes monitoring devices, as well as other methods to monitor, detect, and/or investigate internal corrosion on pipelines. Personnel must be qualified as defined in GS 1400.010 “Corrosion Control – General” in the monitoring, evaluating, etc. tasks below. Samples shall be taken only by experienced personnel or by those who have been instructed in the proper procedures. The list below is not meant to be all inclusive.

3.1 Visual Inspection

Refer to the requirements in GS 1440.010 “Internal Corrosion Inspection Requirements.”

3.2 Evaluating and Monitoring (EM) Coupons

EM coupons can be used to determine a general and local corrosion pitting rate and also identify the cause of internal corrosion (e.g., microbiologically influenced corrosion). Using EM coupons is typically done as a proactive measure for monitoring internal corrosion. EM coupons are typically installed at low points in the system (i.e., at critical angles of inclination), where water or corrosive liquids might collect (refer to IMP 6-15 “Internal Corrosion Direct Assessment Plan” for information on critical angle of inclination).

EM coupons can be evaluated as soon as four weeks after installation, requiring laboratory testing for bacteria and/or byproducts of corrosion. The expected data to be obtained from laboratory testing of the EM coupons are the following:

a. corrosion rate,

b. pit rate

c. presence of microbiologically influenced corrosion (MIC),

d. presence of bacteria/colonies on coupon surface, and

e. presence of scale on coupon surface.

The coupon is weighed and examined using electron microscopy to provide the data listed above. See Section 4 below for inspection requirements. Refer to GS 1440.022 “Internal Corrosion Coupon Installation and Retrieval” for additional guidance.

3.3 Weight Loss Coupons

Weight loss coupons can be used to establish a general and local corrosion pitting rate. They are useful in monitoring normally stable conditions. Using weight loss coupons is typically done as a reactive measure for monitoring corrosion. Weight loss coupons in the dry-gas phase may need to be installed for a longer period of time (e.g., several years) to detect corrosion. See Section 4 below for inspection requirements. Refer to GS 1440.022 “Internal Corrosion Coupon Installation and Retrieval” for additional guidance.

3.4 Probes

There are a variety of different probes that may be used to monitor for internal corrosion in pipelines, such as:

a. resistance probes,

b. polarization probes,

c. hydrogen probes and patches, and

d. electrochemical probes.

Monitoring with probes offers a much higher frequency of sampling than that of coupons. Data collection may be connected to a Supervisory Control and Data Acquisition (SCADA) system for continual or frequent monitoring. Or data collection may be downloaded electronically, if not connected to a SCADA system.

If probes are determined to be the most appropriate internal corrosion monitoring tool for the situation, contact local corrosion leadership for guidance.

3.5 Ultrasonic Inspection

An ultrasonic thickness gauge (UTG) may be used for the detection of internal corrosion. Refer to GS 1430.320 “Ultrasonic Testing Gauge” for additional guidance.

3.6 In-Line Inspection (ILI)

A smart pig or intelligent pig may be used for ILI by using ultrasonic or magnetic flux leakage (MFL) technology to inspect the pipeline by detecting wall loss. Some smart pigs may also use calipers to measure the inside geometry of the pipeline, thereby detecting internal anomalies. Refer to IMP 6-11 “Inline Inspection and Analysis” for additional guidance

3.7 Evaluating Gas Sampling Results

Gas sampling for quality analysis is typically completed by transmission companies at certain locations (e.g., storage facilities) prior to delivering gas to the Company’s city gate stations. Events leading to or observed levels exceeding acceptable gas quality limits (e.g., moisture content) will be reported by the supplier to the Company’s Gas Control department, which shall notify appropriate System Operations leadership (i.e., Gas Systems & Storage Operations Supervisor, M&R Front Line Leader/Supervisor) of gas quality issues that may affect the local area.

Where available, automated Company-owned gas sampling equipment (e.g., moisture analyzers, chromatographs) should be continuously monitored through the Supervisory Control and Data Acquisition (SCADA) system by the Company's Gas Control department. Automated supplier-owned gas sampling equipment may also be monitored through SCADA. Actual observations outside of the acceptable ranges identified in GS 2910.010 "Gas Supply – Gas Quality Specifications" shall be reported to Systems Operations leadership. Systems Operations leadership should forward relevant information (i.e., information with corrosive connotations) to the personnel managing the Company's Pipeline Integrity Program.

Gas constituents typically analyzed from a corrosion standpoint include the following:

a. bacteria,
b. carbon dioxide (CO_2),
c. chloride (Cl),
d. hydrogen sulfide (H_2S),
e. organic acids,
f. oxygen (O_2),
g. solids or precipitates,
h. sulfur-bearing compounds, and
i. water (H_2O).

Gas quality anomalies reported to or observed by the Company's Gas Control department should be recorded in Gas Control's gas quality log, database, or equivalent, and forwarded to the personnel managing the Company's Pipeline Integrity Program. The personnel managing the Company's Pipeline Integrity Program shall determine the risk of internal corrosion and if investigation and/or mitigation is required for Company transmission lines.

3.8 Evaluating Liquid/Solid Sampling Results

Pipeline hydrocarbon free liquids are typically extracted by the suppliers prior to delivering gas to the Company's city gate stations through a scrubber, drip, filter/separator, etc. Upsets to the supplier's extraction facilities will be reported by the supplier to the Company's Gas Control department, which shall notify appropriate Systems Operations leadership of issues that may affect the local area. Systems Operations leadership should forward relevant information (i.e., information with corrosive connotations) to the personnel managing the Company's Pipeline Integrity Program.

Upsets affecting the Company's piping system should be recorded by the Company's Gas Control department in Gas Control's gas quality log, database, or equivalent, and forwarded to the personnel managing the Company's Pipeline Integrity Program.

If liquids or solids are found in the Company's piping system, collect and sample the liquids/solids according to HSE 4400.050(CG), HSE 4400.050(MD), or HSE 4400.050(PA) "Pipeline Liquids Management." The sample should be analyzed for the same gas constituents stated above in Section 3.6.

The personnel managing the Company's Pipeline Integrity Program shall determine the risk of internal corrosion and if investigation and/or mitigation is required for Company transmission lines.

NOTE: Hydrocarbon liquids are typically not corrosive without the presence of water. If free water is detected, additional testing for hydrogen sulfide (H2S), carbon dioxide (CO2) and pH should be performed. Testing for the presence of corrosion producing bacteria (e.g., SRB, APB), may also be performed.

3.9 Internal Corrosion Direct Assessment (ICDA)

Refer to IMP 6-15 "Internal Corrosion Direct Assessment Plan" for additional guidance.

3.10 Trending of Analytical Data

If internal corrosion is occurring within a pipeline system, then trending of analytical data from monitoring points, ICDA results, etc., may be required for determining additional monitoring and remediation efforts.

3.11 Radiography

Radiography may be used to monitor and evaluate internal corrosion defects for remediation decisions.

3.12 Failure Analysis

Failures due to internal corrosion shall be investigated to determine a root cause (refer to GS 1652.010 "Investigation of Failures" for additional guidance). Locations of failures due to internal corrosion may be used to determine the location of internal monitoring devices.

4. INSPECTION REQUIREMENTS FOR INTERNAL CORROSION MONITORING DEVICES

If corrosive gas is being transported, internal corrosion monitoring devices (e.g., corrosion probe, corrosion coupon) shall be inspected two times each calendar year, but with intervals not exceeding 7½ months.

If internal corrosion monitoring devices are installed for other reasons (e.g., pipeline integrity purposes), then monitoring may be adjusted as dictated by the local Pipeline Integrity Management team. The following considerations could impact the frequency of monitoring or testing:

a. location and history of water removal,
b. age and condition of pipe and drips,
c. internal corrosion history, including leaks and ruptures,
d. liquids composition,
e. gas composition,
f. system operating parameters (e.g., temperature, pressure, volumes transported, wet system vs. dry),
g. system physical layout (e.g., topography),
h. flow characteristics,
i. proximity to dwellings and the public,
j. class location, HCAs, or identified sites,
k. pipeline segments downstream of production or storage fields where free water and constituents might accumulate,
l. solids composition,
m. past inspection results,
n. past results obtained using corrosion monitoring devices, and/or
o. system design (e.g., materials of construction, pipe wall thickness, pigging facilities, presence of drips).

If evidence of internal corrosion is found, promptly notify a local corrosion front line leader/supervisor. If internal corrosion is found on a Company transmission line, the local corrosion front line leader/supervisor shall promptly notify the personnel responsible for managing the Company's Integrity Management Program.

A local corrosion front line leader/supervisor, or a designated person qualified in corrosion control, shall initiate an investigation to determine the cause and corrective action necessary to mitigate any further internal corrosion. Refer to GS 1440.010 "Internal Corrosion Inspection Requirements" for additional guidance.

5. INVESTIGATION AND MITIGATION

Refer to GS 1440.010 "Internal Corrosion Inspection Requirements" for investigation and mitigation guidance.

6. RECORDS

Records relating to the inspection of internal corrosion monitoring devices shall be recorded and maintained within the Company's work management system, or equivalent, for the life of the pipeline.

Internal corrosion inspection and investigation related to the Pipeline Integrity Program for transmission lines shall be recorded and maintained within the Pipeline Integrity files and/or database and retained for the life of the pipeline.

NiSource
Distribution Operations

Gas Standard

Effective Date: 12/31/2012	**Internal Corrosion Coupon Installation and Retrieval**	Standard Number: **GS 1440.022**
Supersedes: N/A		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The following procedure provides guidance for installing and retrieving coupons.

2. SPECIFICATIONS FOR COUPONS

The correct coupon type and size must be selected for the specific situation. The coupon comes in different shape and sizes. The pipeline grade of steel (e.g., GR B, X-42, X-65) must be specified to represent the pipeline being monitored for internal corrosion. The coupon shape and size will depend on the coupon holder selected to be installed.

3. CHOOSING THE LOCATION FOR THE COUPON INSTALLATION

Identify the low point in the pipeline that is a critical angle of inclination. The critical angle of inclination is where gas velocity cannot overcome gravity. The critical angle calculation depends on gas pressure, velocity, temperature, composition, and pipe diameter. The formula can be found in IMP-6-15 “Internal Corrosion Direct Assessment Plan.”

A best practice for determining coupon installation location is that if liquid water entered into the pipeline, the likely entry points would be at the point-of-delivery, and the liquid water would be pushed downstream. If any critical angles of inclination were to exist at these entry points, then this location would be the first collection point of liquid water in the pipeline. If after installation and further examination of the coupons indicate no internal corrosion, then the assumption can be made that no corrosion should occur further downstream.

4. INSTALLATION OF THE COUPON HOLDER

A specially designed packing gland is used to insert or retract a coupon from a pressurized system without a process shutdown. The insertion system is designed to mount onto a 1" piping system, but can easily be adapted to fit the specific requirements. The system consists of an insertion rod with a coupon adapter and a packing gland. A safety chain and safety nut are also provided to prevent blowout.

1. Once the welding process is completed and the pipeline has been tapped, measure the depth from the insertion device to the bottom of the pipeline for

coupon installation. The coupon must be positioned within 1/8” of the bottom of the inside pipe wall. Mark the device to keep the coupon parallel with the flow of gas.

2. Install coupon onto retrieval device with great care to avoid contamination. Make sure the coupon is insulated from any metallic connection within the holder. Mark the direction of the coupon to allow it to stay parallel within the pipeline (flat side of the coupon positioned so that it cannot be impinged by substance in the pipeline; flow of gas does not go against the flat surface).

3. Insert coupon retrieval device onto the top valve.

4. Make sure the coupon retrieval device is secured by tightening the locking nut, and open the bleed off valve.

5. Open 2” ball valve slowly, once fully open, insert the coupon until designated mark of depth is reached.

6. Lock the retrieval rod into place and attach the safety chain to prevent accidental movement of the rod.

5. RETRIEVAL OF COUPON

The retrieval process is detailed below.

1. Loosen locking nut.

2. Loosen safety chain.

3. Slowly pull retrieval rod back through the 2” ball valve.

4. Close 2” ball valve.

5. Bleed off retrieval device.

6. Unscrew the retrieval device.

7. Use extreme care to remove the coupon from the retrieval device without contaminating it.

8. Place coupon into neutralizing solution with vial (as per coupon manufacturer instructions).

9. Place ice packs into container with vial.

10. Deliver coupon within 24 hours to approved laboratory.

6. RECORDS

Refer to the records guidance in GS 1440.020 “Internal Corrosion Monitoring.” The following information should be recorded in local corrosion records and/or the Company’s work management system, such as the identification number of the coupon, date of installation, date of retrieval, any noticeable anomalies, temperature of the pipeline, ambient temperature of air, date and time sent for laboratory testing, and/or results of laboratory testing.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Atmospheric Corrosion	Standard Number: GS 1450.010
Supersedes: 12/31/2012		Page 1 of 4

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.479, 192.481, 192.483, 192.491, 192.709

1. GENERAL

This standard covers the general protection and monitoring requirements for distribution and transmission pipelines and related facilities exposed to the atmosphere.

“Atmospheric corrosion” may occur where metal is exposed to the atmosphere with no protective coating. Metal generally will exhibit pitting where the metal is corroded at distinct spots, but may have a uniform deterioration where layers of the metal are converted to corrosion products in such a way that the thickness or pipe wall is uniformly decreased.

Surface oxidation, commonly known as rust, is not considered "atmospheric corrosion" as it generally does not impact pipe wall thickness to the extent that wall strength would be impaired. However, it is considered good practice to recoat aboveground pipelines before the coating has deteriorated to the extent that extensive cleaning or other surface preparation is required.

Each new or replacement pipeline or portion of pipeline installed so that it is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable to prevent atmospheric corrosion.

2. INSPECTION REQUIREMENTS

Pipeline facilities to be inspected include but are not limited to those listed below:

a. inside and outside meter settings,

b. exposed pipeline crossings,

c. gas mains on structures and other above ground locations, and

d. regulator stations.

2.1 Frequency

Each Company shall maintain a continuing monitoring program to inspect each pipeline or a portion of a pipeline exposed to the atmosphere for evidence of atmospheric corrosion at least once every three (3) calendar years, but with intervals not exceeding 39 months.

2.2 Inspection Details

The pipeline shall be visually inspected for evidence of atmospheric corrosion and deteriorating or damaged coating.

Particular attention shall be given to the pipe at the following locations:

a. soil-to-air interfaces,

b. under thermal insulation,

c. under disbonded coatings,

d. at pipe supports,

e. in splash zones,

f. at deck penetrations,

g. in spans over water,

h. at clamps,

i. at rest plates, and

j. at sleeved openings.

This may require ladders, scaffolds, hoists, or other suitable means of permitting inspector access to the structure being inspected.

Piping that is thermally or acoustically insulated (jacketed) should be inspected wherever practical. To minimize damage to the insulation, a visual inspection of the pipe may be performed by cutting windows into the insulation.

Pipeline facilities to be inspected include but are not limited to those listed below:

e. inside and outside meter settings,

f. exposed pipeline crossings,

g. gas mains on structures and other above ground locations, and

h. regulator stations.

3. MONITORING PROGRAM

The inspection may occur on a scheduled basis or during routine operations or maintenance work by field employees. The inspection may be completed in connection with at least one of the following:

a. individual work orders set up to inspect exposed mains and/or services,

b. programmed patrols,

c. leakage surveys, including surveys of customer-owned service lines,

d. regulator and measurement inspections,

e. work involving meters (e.g., changing, reconnections), and/or

f. meter reading operations (inside and outside meters).

3.1 Reporting Areas of Atmospheric Corrosion

As areas of atmospheric corrosion are found during the course of normal Company work activities, they shall be recorded by using existing Company processes (e.g., WMS, NiFast electronic data collection system, atmospheric corrosion database).

If an area of atmospheric corrosion is found on a Company owned **transmission line**, promptly notify a local front line leader/supervisor (see GS 1020.010 “Safety-Related Conditions”). The local front line leader/supervisor shall promptly notify the personnel responsible for managing the Company’s Integrity Management Program for further guidance.

4. REMEDIATION

If atmospheric corrosion is found, actions shall be taken to protect the exposed piping from atmospheric corrosion. If localized atmospheric corrosion is found, and if the existing protective coating is in poor condition or if there is no coating, the pipeline should be scheduled for repair with an approved compatible coating. If generalized atmospheric corrosion is found, which affects the serviceability of the pipeline, the pipeline must be either:

a. repaired by a Company approved method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe, or

b. replaced.

For transmission lines with atmospheric corrosion, promptly notify the local corrosion leadership. A remaining strength calculation shall be completed (refer to GS 1460.020 “Corrosion Remedial Measures – Transmission Lines”). Refer to GS 1730.010 “Transmission Line Field Repair” for acceptable repair methods.

If the pipeline is repaired, it shall be cleaned and either coated or painted with an approved material. All replacement piping shall be installed with the same corrosion control measures as would be applied to a new pipeline. Refer to GS 1420.050 “Coating Methods for Fabricated Stations & Settings.” In addition, the soil to air interface(s) shall be checked. If there is no coating or the existing coating is deficient, clean and coat according to GS 1420.050 “Coating Methods for Fabricated Stations & Settings.”

For atmospheric corrosion found at pipe supports, on rest plates, etc., the pipeline and supports shall be separated with the use of fiber reinforced plastic (FRP) shields, or an equivalent material or method, and coated properly.

For atmospheric corrosion found at sleeve openings, the pipeline shall be coated properly with sleeve openings sealed to prevent water from entering the sleeve.

Refer to applicable gas standards on pipeline repair, coating repair, and remedial measures for additional guidance.

Remediation shall be scheduled and completed as soon as practical based on the severity of the atmospheric corrosion condition, but in no case shall the completion of the remedial work extend past three (3) years since the condition was reported.

5. RECORDS

The Company shall retain atmospheric corrosion inspection records identifying atmospheric corrosion and remediation within the Company's work management system, or equivalent documentation, for a minimum of ten (10) years, plus the current year.

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Corrosion Remedial Measures – Distribution**	Standard Number: **GS 1460.010**
Supersedes: 01/01/2015		Page 1 of 6

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.483, 192.487, 192.489

1. GENERAL

Distribution pipeline (e.g., mains, service lines, fittings), buried or submerged, found to be damaged by external corrosion shall be replaced, repaired or removed from service in accordance with the following guidelines.

For pipelines exposed to the atmosphere, refer to the applicable GS 1450.010 "Atmospheric Corrosion."

If corrosion is suspected to have caused a material failure, refer to GS 1652.010 "Investigation of Failures" for additional guidance.

2. DISTRIBUTION LINES OTHER THAN CAST IRON OR DUCTILE IRON

2.1 General Corrosion

General corrosion is considered corrosion pitting so closely grouped as to affect the overall strength of the pipe and should be considered as affecting the pipeline's serviceability.

If general corrosion is suspected, contact a front line leader/supervisor or local corrosion personnel for confirmation.

Except for cast iron or ductile iron pipe, each segment of generally corroded distribution main or service line with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be taken out of service or replaced according to the remediation schedule stated below. However, when general corrosion is limited to a small area, not to exceed the design parameters of available repair technologies (e.g., composite wrap), the serviceability of the pipe may be restored through repairs. Contact local corrosion personnel for assistance, if necessary, for determining if the pipeline should be replaced or removed from service or if it can be adequately repaired.

Remediation shall be scheduled and completed as soon as practical based on the following:

a. the severity of the general corrosion, and

b. the physical characteristics related to the facility that may cause a situation to become detrimental to public safety (e.g., operating pressure, proximity to conduits, type of cover, external stresses).

If the project is subjected to significant delays (e.g., material acquisition, permit approval), the area shall be patrolled on a periodic basis until the project is completed.

2.2 Localized Corrosion Pitting

Localized corrosion pitting is a leaking or non-leaking area on the pipe surface that contains corrosion pits over a non-contiguous area. Localized corrosion does not necessarily affect a pipe's serviceability.

Except for cast iron or ductile iron pipe, each segment of a distribution main or service line with localized corrosion pitting to a degree where leakage might result must be replaced, repaired or removed from service. Field employees must make a judgment based on training and experience to determine if an existing corrosion pit might result in leakage.

Remediation shall be completed as directed by the applicable GS 1714.010 "Leakage Classification and Response."

2.3 Maintenance of Pipelines Exposed for Leak Repair or Other Reason

2.3.1 Pipe-to-Soil Potential Measurement

A pipe-to-soil potential measurement shall be obtained prior to the installation of an anode (Section 2.3.3) and/or application of an approved coating (Section 2.3.2).

The pipe-to-soil potential measurement shall be taken within the excavation and recorded on the related leak repair work order. The reference electrode shall make contact with undisturbed soil in the excavation and placed at a location near the pipeline (without making physical contact with the pipe) while obtaining the measurement. Refer to GS 1430.110 "Pipe-to-Soil Potential Measurements."

2.3.2 Installation of Approved Coating

Except for cast iron or ductile iron, all bare metallic pipelines shall be coated with an approved coating whenever the pipeline is uncovered and the pipeline surface condition is changed. Damage to existing coatings shall be repaired by using an approved coating. All metallic fittings or pipe installed shall be coated with an approved coating. Refer to GS 1420.035 "Coating Repair Methods for Mill Applied Coatings" and/or GS 1420.040 "Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances" for guidance on approved coatings.

Whenever a metallic riser is exposed, the soil to air interface shall be coated or the existing coating shall be repaired, if necessary, according to GS 1420.050 "Coating Methods for Fabricated Stations & Settings," Section 4.

2.3.3 Installation of Anode(s)

Whenever an isolated metallic fitting is installed (i.e., within a plastic piping system), an anode (e.g., 1 lb. zinc anode or equivalent) shall be installed.

Whenever a short section of pipeline is replaced or an existing steel pipeline (including metallic risers) is exposed for leak repair, maintenance, replacement, additions or for other reasons, magnesium anodes (drive-in or spike anode for service riser; 9 lb high potential magnesium anode or equivalent on bare pipeline; 17 lb high potential magnesium anode or equivalent on coated and protected pipeline) shall be installed. The only exceptions to this requirement are when:

a. the pipeline is cathodically protected by an impressed current cathodic protection system, or

b. the pipeline is determined to be under adequate cathodic protection as evidenced by a pipe-to-soil reading of -1.000 volts in reference to a copper-copper sulfate electrode or more negative.

NOTE: An impressed current cathodic protection system may have had its rectifier turned off for work, such as welding or cutting/tie-ins. After a period of time, the pipeline may have had time to depolarize (lose its protection). This could result an inadequate pipe-to-soil reading. If this is the case, <u>do not</u> install an anode. Refer to the corrosion recommendations on Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements" (see GS 1420.010 "Corrosion Control Design – General") or contact local corrosion personnel for clarification, if necessary.

When these exceptions are not met, a minimum of one anode shall be installed. Where more than 10 feet of metallic pipe is exposed, additional anodes shall be installed. Table 1 shall be used as a guide. Local corrosion personnel may specify more precise spacing for particular pipe size and earth resistivity.

Table 1

Pipeline Length (Feet)	Bare Pipe	Coated Pipe
Up to 10	1 Anode	1 Anode
10 - 20	2 Anodes	1 Anode
Over 20	2 Anodes plus 1 for each additional 10 feet	2 Anodes plus one for each additional 40 feet

Where a single anode is required, it should be installed near the center of the pipeline section. When two (2) anodes are required, they should be installed near the ends of the exposed pipeline section. When three (3) or more anodes are required, one should be installed near each end of the pipeline section and the remainder equidistant between adjacent anodes.

Refer to GS 1420.510 “Installation of Galvanic Anodes” for additional guidance.

2.3.4 Installation of Test Station

Whenever a corrosion leak is repaired on a coated steel pipeline, a test station shall be installed. Refer to GS 1420.520 “Installation of Test Stations” for additional guidance.

3. CAST IRON AND DUCTILE IRON PIPELINES

Refer GS 1780.010 “Cast Iron – General” for more information and guidance on cast iron pipelines.

3.1 General Graphitization

General graphitization is considered **graphitization** of cast iron that occurs so closely grouped that it affects the overall strength of the pipe and should be considered as affecting the pipeline’s serviceability.

Each segment of cast iron or ductile iron pipe on which general graphitization is found must be replaced or removed from service.

If general graphitization is suspected, contact a front line leader/supervisor or local corrosion personnel for confirmation.

Remediation shall be scheduled and completed as soon as practical based on the following:

a. the severity of the general graphitization, and

b. the physical characteristics related to the facility that may cause a situation to become detrimental to public safety (e.g., operating pressure, proximity to conduits, type of cover, external stresses).

If the project is subjected to significant delays (e.g., material acquisition, permit approval), the area shall be patrolled on a periodic basis until the project is completed.

3.2 Localized Graphitization

Localized graphitization is a leaking or non-leaking area on the pipe surface that contains graphitization over a non-contiguous area. Localized graphitization does not necessarily affect a pipe's serviceability.

Each segment of cast iron or ductile iron pipe on which localized graphitization is found must be replaced, removed from service, repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

The pipe may be repaired by a clamp or sleeve, provided that the repair clamp or sleeve will cover the graphitized area and the ends of the repair clamp or sleeve are over sound, non-graphitized pipe. Refer to the applicable GS 1714.020 "Leakage: Distribution Pipe Repair."

Remediation shall be completed as directed by the applicable GS 1714.010 "Leakage Classification and Response."

4. ISOLATED STEEL SERVICE LINES AND RISERS

Leaking isolated steel service lines shall be replaced with plastic pipe, where appropriate. If this is not feasible, contact local corrosion personnel for corrosion control recommendations.

Leaking isolated steel service risers shall be replaced with an approved anodeless riser, where appropriate. If this is not feasible, contact local corrosion personnel for corrosion control recommendations.

5. CASING

Corrosion found on casing pipe does not require repair, unless the casing is located above ground (e.g., encased bridge crossing). Refer to the applicable GS 1450.010 "Atmospheric Corrosion" for additional remediation guidance.

6. REPLACEMENT GUIDELINES

Considerations for replacement include, but are not limited to the following:

a. open leakage,

b. leakage history,

c. depth of cover,

d. adjacent conduits (e.g., sewer lines, abandoned facilities) that could allow for leakage migration,

e. current or future construction activity,

f. pipe exposure data,

g. internal corrosion history,

h. operating pressure, or

i. other issues that might affect safety or economics.

For cast iron and ductile iron pipelines, refer to the applicable GS 1782.010 “Protecting Cast Iron Pipelines” for additional replacement guidance.

In addition, each segment of a metallic pipe that replaces a pipe removed from a buried or submerged pipeline shall have a properly prepared surface and an external protective coating in accordance with applicable corrosion design gas standards and be cathodically protected in accordance with GS 1420.020 “Criteria for Cathodic Protection.”

7. REPAIR GUIDELINES

Refer to the applicable GS 1714.020 “Leakage: Distribution Pipe Repair” for guidance.

8. RECORDS

Repairs or replacement of pipelines, or pipelines that are removed from service, shall be documented in the Company’s work management system, or equivalent, and on the following form, if applicable:

For KY, MA, MD, OH, & PA: Complete Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” (refer to applicable GS 1708.100 “Leakage Control Records”).

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	Corrosion Remedial Measures – Transmission Lines	Standard Number: **GS 1460.020**
Supersedes: 12/31/2012		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.483, 192.485

1. GENERAL

Transmission lines, buried or submerged, found to be damaged by external corrosion must be replaced, repaired or removed from service in accordance with the following guidelines.

Corrosion found on a transmission line shall be promptly reported to the personnel responsible for managing the Company's Integrity Management Program.

For pipelines exposed to the atmosphere, refer to the applicable GS 1450.010 "Atmospheric Corrosion."

If corrosion is suspected to have caused a material failure, refer to GS 1652.010 "Investigation of Failures" for additional guidance.

2. DETERMINING STRENGTH OF PIPE

Where the wall loss, due to corrosion, is not greater than 80%, the strength of the remaining wall thickness may be determined by using **RSTRENG®** to verify that the facility is commensurate with the present maximum allowable operating pressure (MAOP).. ASME B31G is an acceptable alternative to **RSTRENG®** in certain situations, such as when a detailed profile cannot be obtained.

RSTRENG® or ASME B31G calculations shall be performed by an engineer or a corrosion front line leader/supervisor trained to use these programs. Pit depth measurements along the corrosion pitted area shall be taken by a corrosion person trained to take these measurements.

3. GENERAL CORROSION

Each pipe segment of a transmission line with **general corrosion** and with a remaining wall thickness less than that required for the MAOP of the transmission line must be replaced, removed from service, or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, when general corrosion is limited to a small area, not to exceed the design parameters of available repair technologies (e.g., composite wrap), the serviceability of the pipe may be restored through repair in accordance with GS 1730.010 "Transmission Line Field Repair."

NOTE: See GS 1020.010 “Safety-Related Conditions – Recognition, Notification, and Reporting” for pipelines that operate at a hoop stress of 20 percent or more and where general corrosion is found.

4. LOCALIZED CORROSION PITTING

Each segment of transmission line pipe with **localized corrosion pitting** to a degree where leakage might result must be replaced, repaired, removed from service, or the operating pressure must be reduced commensurate with the strength of the pipe (see Section 2) based on the actual remaining wall thickness in the pits.

NOTE: See GS 1020.010 “Safety-Related Conditions – Recognition, Notification, and Reporting” where localized corrosion pitting on a transmission line exists to a degree where leakage might result.

5. REPLACEMENT GUIDELINES

Considerations for replacement include, but are not limited to the following:

a. strength of pipe calculations from RSTRENG® or ASME B31G,

b. open leakage,

c. leakage history,

d. depth of cover,

e. adjacent conduits (e.g., sewer lines, abandoned facilities) that could allow for leakage migration,

f. current or future construction activity,

g. pipe exposure data,

h. internal corrosion history, or

i. other issues that might affect safety or economics.

In addition, each segment of a metallic pipe that replaces a pipe removed from a buried or submerged pipeline shall have a properly prepared surface and an external protective coating in accordance with applicable corrosion design gas standards (GS 1420.030 “Mill Applied Coatings,” GS 1420.035 “Coating Repair Methods for Mill Applied Coatings,” and GS 1420.040 “Coating Methods for Girth Welds, Fittings, Risers, & Other Below Grade Appurtenances”) and be cathodically protected in accordance with GS 1420.020 “Criteria for Cathodic Protection.”

6. REPAIR GUIDELINES

Refer to GS 1730.010 “Transmission Line Field Repair” for guidance.

7. RECORDS

Repairs or replacement of pipelines, or pipelines that are removed from service, shall be documented in the Company work management system, or equivalent, and the Company's Integrity Management files.

Information regarding the repair or replacement of pipelines or pipelines that are removed from service due to leaks shall also be documented on the following forms:

a. For KY, MA, MD, OH, PA, & VA: Complete Form GS 1714.100-1 “Distribution Plant Inspection and Leakage Repair” (refer to the applicable GS 1708.100 “Leakage Control Records”).

b. For IN: Complete Standard Form 311-61 “Leak Survey Data Entry Form” (refer to Gas Standard 500-0010 “Leak Reports and Surveys”).

Results and input data from RSTRENG or ASME B31G analysis used to support the MAOP of the pipe that remains in service must be retained in the Pipeline Integrity files and/or the Engineering files, as appropriate, for the remaining life of the facility.

Refer to GS 1730.010 “Transmission Line Field Repair” for additional documentation and record retention requirements.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Investigating Leak Cause on Coated Pipeline	Standard Number: **GS 1460.030**
Supersedes: 01/01/2015		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

For Columbia Gas companies, the Company's work management system (WMS) generates a corrosion work order (e.g., CORR) when a pipeline exposure is associated to the repair of a leak that is on a coated pipeline (i.e., pipe or facility).

At NIPSCO for each pipeline exposure, field personnel fill out the "Buried Metallic Piping - Inspection Report" (see NIPSCO Gas Standard 800-0040 "Corrosion - System Maintenance - System Surveillance"). A pipeline exposure associated to the repair of a leak that is on a coated pipeline (i.e., pipe or facility) is forwarded to corrosion personnel for investigation.

The local corrosion personnel is required to complete a prompt investigation to determine the root cause of the leak on coated pipeline and recommend corrective action for cathodically protected pipeline, if necessary.

This standard provides guidance for corrosion personnel to perform an investigation of a leak found on coated pipeline.

2. INITIAL INVESTIGATION

First, gather existing data, such as the following.

a. Check corrosion records to determine if pipeline is part of a cathodic protection (CP) system. Some coated pipelines, installed prior to August 1, 1971, may not be cathodically protected. If it is cathodically protected, determine the type of CP system (i.e., galvanic anode system or impressed current system).

b. Review the pipeline exposure data associated with the leak, particularly documentation of coating condition and type of repair.

c. Review the pipeline exposure data associated with the leak for a pipe to soil potential reading.

d. Review historical CP readings if the pipeline is part of a CP system.

The investigation is considered complete if review of existing data indicates that the leak was:

1. on a non-cathodically protected pipeline or

2. not related to corrosion (e.g., mechanical fitting tightened, gate valve needed packed)..

If the leak was found on CP pipeline, continue with investigation steps in the following sections.

3. FURTHER INVESTIGATION GUIDANCE

The following tasks shall be completed to prove that pipeline has adequate CP and/or to determine the root cause of a leak on CP pipeline.

3.1 Close Interval Survey

Perform a close interval survey at the location of the leak. The survey shall extend at least 100 feet on each side of the leak location. Intervals shall be kept at a maximum of 5 ft. between readings. Refer to GS 1430.120 “Close Interval Survey” for additional guidance.

3.2 Continuity/Isolation Verification

Establish continuity with the rest of the CP system by checking for unknown insulators. Verify isolation from potential electrical shorts to the CP system. Refer to GS 1430.250 “Verifying Electrical Continuity and Isolation.”

3.3 Review Comments or Interview Leak Repair Crew

If work management system comments are insufficient, ask questions regarding original backfill surrounding leaking pipeline. If large rocks were found in close proximity to the pipeline, then CP shielding could have occurred. Also verify what was leaking and where. This could help determine whether the leak was related to corrosion.

4. DATA REVIEW

Review all data collected for the following indications.

a. Check for pipe to soil potential readings close to and/or below -0.850V cse (i.e., criteria for CP). If any pipe to soil potential readings are below criteria, this indicates insufficient CP.

b. Complete soil resistivity tests at leak location. High soil resistivity may have contributed to insufficient CP.

c. Check for any peaks or valleys (i.e., high negative or positive pipe to soil potential readings), which may be an indication of stray currents in the area.

d. Check for indication of an unknown insulator.

e. Check for indication of electrical shorts. After removal of electrical short(s), additional reinvestigation may be required (see Section 3 above).

5. CONCLUSIONS AND FURTHER ACTIONS

The following conclusions of root cause may be made based on the review of data in Section 4 above. Further actions may be required to get the pipeline under adequate CP.

5.1 Unknown Insulator / Lack of Continuity

Additional troubleshooting may be required to determine if a section of pipeline is isolated from CP. Further actions may also include the design and installation of additional test stations, bond(s), and/or additional CP material for effective CP.

5.2 Stray Current

Additional troubleshooting may be required to establish the maximum depressed area and the pick-up area by synchronizing interruption of all influence impressed current systems. Refer to GS 1420.100 “Corrosion Control Design – Stray Current Control.” Design and oversee installation of critical resistance bond to bring potentials of the depressed area to sufficient CP. Refer to GS 1420.105 “Corrosion Control Design – Bonds.”

5.3 Cathodic Shielding

If the data review shows that CP system is sufficient, but coating disbondment, poor coating, or debris against the pipeline was recorded on pipe exposure or found through further investigation or interviewing, conclusion may be made that cathodic shielding occurred. No further action is required.

5.4 Microbiologically Influenced Corrosion

If data review shows that CP system is sufficient and coating is in good condition, further investigation is needed to determine if microbiological induced corrosion (MIC) is the root cause of the leak. Refer to GS 1430.324 “Microbiologically Influenced Corrosion.”

Further action required includes additional design and remediation, such as use of MIC inhibitors and/or the raise of CP pipe to soil potentials above criteria, according to remediation guidance in GS 1430.324 “Microbiologically Influenced Corrosion.”

5.5 Possible High IR Drops

If data review shows that CP system is sufficient, coating is in good condition, and no evidence of MIC has been found, install an IR coupon to measure for possibility of high

IR drops in the area.

Further action required includes the installation of an IR coupon test station (refer to GS 1420.095 “Corrosion Control Design - Test Stations”) and determination of the measurement of the IR drop. This may require further current requirement testing (see GS 1430.230 “Current Requirement Test”) and additional CP materials.

6. RECORDS

Records documenting the investigation and root cause of the leaks on coated pipeline shall be retained in the Company’s work management system or equivalent. Records demonstrating the adequacy of corrosion control measures or that a corrosive condition does not exist shall be retained for at least five (5) years, plus the current year. Surveys supporting records in the Company’s work management system shall be referenced in WMS work order comments and filed in local corrosion records (e.g., circuit pack file), or mainline history file, as applicable.

Distribution Operations

Gas Standard

Effective Date: 06/01/2016	Pressure Testing	Standard Number: GS 1500.010
Supersedes: 01/01/2013		Page 1 of 30

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☐ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192 Subpart J, 192.285 (c)

1. GENERAL

The following provisions apply to pressure tests, regardless of the test medium.

a. Prior to being placed in-service, the Company will pressure test all new, replaced, relocated, disconnected and previously abandoned mains, transmission lines, service lines, tie-in joints and attached gas carrying facilities by a leak test and/or strength test to:

   i. Eliminate all potentially hazardous leaks, and

   ii. Establish the maximum allowable operating pressure (MAOP) in accordance with GS 1660.010 or GS 1660.010(PA) “Maximum Allowable Operating Pressure.”

b. All main line valves, internal to the system being tested, shall be in the open position. Service line valves shall be tested for "leak-through" by testing them in the closed position. Since a blind plate would prevent the detection of “leak through”, a blind plate shall not be used when conducting service line tests.

c. Any section of a main or transmission line that has been tested prior to installation shall be re-tested with the complete project before the project is placed in service. Tie-in joints, fittings and measuring/regulator station piping may be exempted from this requirement. Refer to Section 9.

d. A pre-installation test should be considered for special construction such as main insert; river, highway, railroad, and bridge crossing; and measurement/regulator station piping.

e. If internal cleaning of the pipeline is necessary it shall be done prior to testing.

f. After testing, the pipe should be kept pressurized or pipe ends covered until the pipeline is ready to be placed in service.

g. Prior to beginning a pressure test the test plan shall be reviewed with all personnel involved in the testing, including Section 3 of this standard. If any changes are made to the test plan the changes shall be communicated to all personnel affected by the changes.

For the purpose of this standard unless otherwise noted the use of the word test, testing, tested shall mean pressure test.

2. RESPONSIBILITY

It is the responsibility of the Company's Representative, whether employee or contractor, to ensure that pressure tests are conducted in accordance with this standard. The Company's Representative shall be present when the test is started and when the test is terminated, and shall record the test results except for fabricated sections tested off site. The test shall be repeated if deemed necessary by the Company's Representative.

3. SAFETY DURING PRESSURE TESTING

The following safety precautions shall be considered during the pressure testing procedure.

a. All practical steps shall be taken to keep the public outside the testing area until the test is completed.

b. Monitoring of road crossing and the pipeline right-of-way for pedestrian congregation shall be required for the following conditions.

   i. When a pipeline of 720 psig design or higher is being tested, or

   ii. For any test in which the stress in the pipeline will exceed 50% of the specified minimum yield strength (SMYS) of any component in the system.

c. Consideration shall be given to wearing face and eye protection when working with pressurized or compressed gases, including air and when working in any environment where airborne particles may be present.

d. Testing against a temporary stopping device, such as a "Mueller" plug, “TD Williamson” stopple, or bag, is prohibited. Testing against a closed main line valve that is not blind plated is also prohibited.

e. It is recommended to backfill as much as practical before testing.

f. The hazards of testing exposed piping shall be considered, regardless of the test medium. The hazards associated with testing unburied pipe are greatly diminished when using water as a medium.

g. All test connections must be exposed and of adequate rating for the test pressure.

h. When an inert gas is used as any part of the test medium, it shall be vented to the atmosphere through a pipe extension at least seven (7) feet above the ground.

i. Personnel operating the valve that controls the relief of the test pressure shall wear approved ear protection. All other personnel shall be at a distance where the noise is not at a harmful level.

j. A muffling device should be used to reduce noise in urban areas as the pressure is relieved to atmosphere. The use of a muffling device should be determined based on the test pressure and velocity of air or inert gas to be released.

k. Mechanical couplings may be used to connect the test header to the test section whenever the test pressure will not exceed 125 psig (or rating of the coupling, whichever is less) and the pipeline diameter is smaller than 10 inch.

l. Non-restraint mechanical compression caps and couplings, if used, shall be strapped and/or blocked regardless of the test pressure. All fittings used shall be rated for the test pressure.

m. For a pressure test duration greater than one (1) hour a tag to indicate the pipeline is under pressure shall be attached to all exposed segments of the pipeline under test. The tag should be attached prior to pressurizing the pipeline and removed upon completion of the pressure test.

n. During the testing operation, all personnel shall be kept clear of the pipeline and test equipment under pressure. Those performing the test shall be near the piping only when necessary and there shall be no work on or around the piping system during the test and when the test pressure is being relieved to atmosphere.

o. Before any fittings are loosened or removed on the pipeline under test the test medium shall be fully relieved to atmosphere through a valve. Caution shall be taken to prevent damage to the surrounding area as the pressure is being relieved to atmosphere. **Personnel involved with the test** shall be notified after the pressure in the pipeline has been fully relieved to atmosphere.

4. TEST PLANNING

Prior to each test, the following shall be determined.

a. The extent of system to be tested.

b. The pressure rating of test fittings.

c. The safety procedures to be followed.

d. The testing medium.

e. The volume of inert gas needed. (See Exhibit B “Method to Determine Inert Gas Requirements.”)

f. The pressure and time duration of the test.

g. The injection location of the testing medium.

h. The location on the test section where test instruments shall be located.

i. The disposal of testing medium.

5. PRESSURE INDICATING AND RECORDING GAUGES

5.1 Pressure Gauge Requirements

a. Only a calibrated pressure gauge shall be used to measure the required test pressure. See GS 1754.010 "Operation & Maintenance of Pressure Gauges" for calibration requirements.

b. Either a mechanical gauge (indicating or pen recording) or a digital gauge (indicating or recording) shall be used to measure the required test pressure.

c. The range of the gauge(s) selected will be such that adequate interpretation of the pressure is possible.

d. An indicating gauge may be used for tests where the required test duration is one (1) hour or less.

e. A recording gauge shall be used to record the test pressure for tests that require durations greater than one (1) hour.

f. When contractor-owned indicating or recording gauges are used, a calibration record for the gauge(s) shall be available to the Company.

5.2 Pressure Gauge Accuracy

The accuracy of the gauge shall be considered when determining the minimum test pressure.

Notes:

1. Mechanical gauges typically will have a full scale accuracy of 2%. A calibrated 0 to 200 psig gauge with a full scale accuracy of 2% will be accurate to within ±4 psig.

2. Digital gauges typically will have a full scale accuracy of 0.5% or less. A calibrated 0 to 200 psig gauge with an accuracy of 0.5% will be accurate to within ±1 psig.

The scale displayed by a digital gauge can be set to indicate whole numbers or one or more decimal places. During the stabilization period a digital gauge should be set to display one decimal place to assist with determining when pressure equalization is attained. After pressure equalization is attained, the digital gauge should be set to show whole numbers (no decimal place) for the duration of the test.

6. TEST MEDIUM

The test medium shall be water, air, inert gas or natural gas. If water is selected as the test medium refer to GS 1500.020 "Hydrostatic Pressure Testing."

The amount of stress applied to a steel pipeline is limited when air, inert gas or natural gas is used as the test medium. The maximum stress limits are shown in Table 1 as a percentage of Specified Minimum Yield Strength (SMYS) of the steel pipe being tested. When the maximum hoop stress for air or inert gas will be exceeded, the testing medium shall be water.

The hazards of testing exposed piping shall be considered when selecting test medium. The hazards associated with testing unburied pipe are greatly diminished when using water as a medium.

When a pressure test is to be performed using inert gas consult Exhibit B for determining the quantity of inert gas required. If an air compressor is used check to ensure it is rated for the pressure required.

Table 1

Maximum Hoop Stress Allowed as Percentage of SMYS		
Class Location	Natural Gas	Air or Inert Gas
1	80	80
2	30	75
3	30	50
4	30	40

7. TEST PRESSURE AND DURATION

Except as noted in Section 9 “Testing Requirements for Certain Applications,” Table 2 and its associated Notes describes minimum test pressure and duration requirements for new, replaced, relocated, disconnected and previously abandoned mains, transmission lines and service lines.

The accuracy of a pressure gauge shall be considered when determining the minimum test pressure. For additional information see Section 5.

Test start time commences after pressure of test medium is considered stabilized. For additional information refer to Section 8.

Each required test shall be documented in accordance with Section 11.

Table 2

MINIMUM TEST PRESSURE AND DURATION		
	All Mains, All Transmission Lines and All 3" and Larger Service Lines	**Service Lines Smaller Than 3"**
Plastic Pipe	**Duration**: See Section 7.2 1 hour minimum Not more than 16 hours required	**Duration**: Lengths 300 feet and less; 5 minutes minimum Lengths greater than 300 feet; See Note 6
	Pressure: Whichever is greater of the following, except as stated in Note (10): − 90 psig for MDPE − 150 psig for SDR 11 HDPE or − 1.5 times MAOP	**Pressure**: Whichever is greater of the following, except as stated in Note (10): - 90 psig for MDPE. - 150 psig for SDR 11 HDPE - 1.5 times MAOP
	See Notes: (1), (4), (10)	**See Notes**: (1), (6), (7), (10)
Steel Pipelines: less than 100 psig	**Duration**: See Section 7.2 1 hour minimum Not more than 16 hours required	**Duration**: Lengths 300 feet and less; 5 minutes minimum Lengths greater than 300 feet; See Note 6
	Pressure: Greater of: 1.5 x MAOP or 90 psig	**Pressure**: Greater of: 1.5 x MAOP or 90 psig
	See Notes: (4)	**See Notes**: (6), (7), (9)
Steel Pipelines: Greater than or equal to 100 psig and less than 30% SMYS	**Duration**: See Section 7.2 1 hour minimum Not more than 16 hours required	**Duration**: Lengths 300 feet and less; 5 minutes minimum Lengths greater than 300 feet; See Note 6
	Pressure: 1.5 x MAOP (See Note 8)	**Pressure**: 1.5 x MAOP
	See Notes: (2), (3)	**See Notes**: (3), (6), (7)
Steel Pipelines: 30% SMYS or greater	**Duration**: See Section 7.2 8 hour minimum Not more than 16 hours required	**Duration**: 8 hour minimum Not more than 16 hours required
	Pressure: 1.5 x MAOP	**Pressure**: 1.5 x MAOP
	See Notes: (2), (3), (5)	**See Notes**: (3), (5), (7)

Notes for Table 2:

1. During the test the temperature of the plastic pipe and fittings shall not be more than 140 °F and the test pressure shall not be higher than three (3) times the calculated design pressure of the pipe based on the temperature of the pipe during the test. The plastic pipe used by NiSource meets this requirement because it has a Hydrostatic Design Basis (HDB) of 1,000 psi at 140° F and three (3) times the calculated design pressure (using a HDB of 1,000 psi) is higher than the required test pressure for all pipe sizes used.
2. For a steel main where the final test pressure will stress the line to 20% SMYS or greater with air, inert gas or natural gas as the test medium, a leak test of one (1)

hour must be made at a pressure between 100 psig and the pressure required to produce a hoop stress of 20% of SMYS or the line must be walked to check for leaks while the hoop stress is held at approximately 20% of SMYS.

3. The maximum allowed hoop stress on the pipe during the test is limited as shown in Table 1 when test medium is natural gas, air or inert gas. The maximum allowed hoop stress in the pipe during the test is 110% SMYS when the test medium is water.

4. The minimum pressure test duration is reduced to 20 minutes, providing all of the following conditions are met, except as noted in Section 7.2, "Test Pressure Duration Calculation":

   a. nominal pipe size is eight (8) inches or less;

   b. pipe test length is 40 feet or less; and

   c. there are no joints or fittings (other than to attach the testing apparatus).

5. In Class 1 and 2 locations, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125% of maximum operating pressure (MOP) on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet, unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50% of SMYS, air or inert gas may be used as the test medium. Refer to GS 1500.020 "Hydrostatic Pressure Testing."

6. Longer test durations apply for service lines smaller than three (3) inch with a length greater than 300 feet (See Section 7.2.)

7. The test duration for service lines three (3) inch and larger shall be the same as listed for mains and transmission lines in Table 2.

8. Consideration should be given to test at a pressure 1.5 times the pressure necessary to produce a stress of 20% SMYS to allow for future pressure upgrades.

9. Services to be reinstated shall be tested as new, except for bare steel operating at low pressure which may be tested at 10 psig.

10. High Density Plastic Pipe (HDPE) with a SDR 11 shall normally be tested at a minimum pressure of 150 psig for a 99 psig MAOP with the following exceptions as approved by the Engineer responsible for the design.

    i. HDPE with different Standard Dimension Ratios (SDR) can require a higher or lower minimum test pressure for the desired MAOP. For example, SDR 9.0 HDPE pipe has a MAOP of 125 psig and minimum test pressure of 187.5 psig, SDR 17 HDPE pipe has a MAOP of 60 psig and a minimum test pressure of 90 psig.

ii. When HDPE is used in a system with a MAOP less than 99 psig, a test pressure to match the existing MAOP may be used. For example, HDPE is sometimes use for a directionally drilled portion of a medium density plastic (MDPE) system due to its increased tensile strength and abrasion resistance. In this case the HDPE may be tested at a minimum pressure of 90 psig.

7.1 Test Pressure Limitations for Flanged Fittings and Valves

Test pressure on flanged fittings and valves shall not exceed the maximum test pressure outlined in Table 3.

Table 3

Test Pressure Limitation for Flanged Fittings and Valves		
Valve Class or Class Designation (ANSI)	**Working Pressure[1] (psig)**	**Maximum Test Pressure[2] (psig)**
150	285	450
300	740	1125
400	985	1500
600	1480	2225
900	2220	3350

1. Maximum working pressure ratings for flanged-end, gate, plug, ball and check valves @ 100ºF. Higher temperatures will de-rate this number.

2. Maximum test pressure equals 1.5 times the working pressure rounded up to the next 25 psig increment. If the maximum test pressure may be exceeded, valves and fittings may need to be cut-in after testing, or the next valve or fitting class may be used, or the valve manufacturer can be consulted to determine if the brand of valve in use has a higher tolerance. Pressure ratings for pre-1973 valves and fittings need to be verified with the manufacturer.

7.2 Test Pressure Duration Calculation

The test time starts after the test medium has been injected into the pipeline facility being tested and the pressure of the test medium is allowed to stabilize. The test time ends immediately prior to relieving the pressure in the pipeline to atmosphere. Ensure the required pressure test duration has been achieved prior to relieving the pressure in the pipeline to atmosphere, i.e., ending the test.

Shorter test durations may be allowed for emergency situations, such as, work associated with pipeline damages or to mitigate service outages. Such tests shall be approved by the field leader or engineer/engineering technician and the reason so stated on the work order. In no case shall the test duration be less than is derived using Equation 1 and never less than 20 minutes.

Table 2 above gives the minimum test durations required by code. For mains and transmission lines, the minimum test duration is one (1) hour, or eight (8) hours for a pipeline that will be operated at a hoop stress of 30% or more. Maximum test duration for mains and transmission lines is 16 hours. Longer lengths and larger diameters of pipelines require additional testing time to ensure all potentially hazardous leaks are discovered. Equation 1 shown below is used to calculate minimum test durations. The test durations in Table 4 were derived using Equation 1.

$$\mathbf{T = L \times D^2 / 8000} \qquad \textbf{(Equation 1)}$$

Where:

T = test duration, in hours

L = length of test segment, in feet

D = nominal pipe size, in inches

Table 4

Minimum Pressure Test Durations in Hours:Minutes for Given Pipe Size and Length for Mains and Transmission Lines											
Nominal Pipe Diameter	**Length of Pipe Test Section in Feet**										
	200 or Less	**300**	**500**	**750**	**1000**	**1500**	**2000**	**2500**	**3000**	**3500**	**4000**
1.25”	0:02	0:03	0:05	0:08	0:11	0:17	0:23	0:29	0:35	0:41	0:46
2”	0:06	0:09	0:15	0:22	0:30	0:45	1:00	1:15	1:30	1:45	2:00
3”	0:13	0:20	0:33	0:50	1:07	1:41	2:15	2:48	3:22	3:56	4:30
4”	0:24	0:36	1:00	1:30	2:00	3:00	4:00	5:00	6:00	7:00	8:00
6”	0:54	1:21	2:15	3:22	4:30	6:45	9:00	11:15	13:30	15:45	16:00
8”	1:36	2:24	4:00	6:00	8:00	12:00	16:00	16:00	16:00	16:00	16:00
10”	2:30	3:45	6:15	9:22	12:30	16:00	16:00	16:00	16:00	16:00	16:00
12”	3:36	5:24	9:00	13:30	16:00	16:00	16:00	16:00	16:00	16:00	16:00

Note: Shaded cells are values below one (1) hour that were calculated using Equation 1. To determine the required test duration for multiple segments tested together; sum the required test duration for each segment to determine the total test duration with consideration to minimum and maximum test durations.

7.3 Example Test Duration Calculations:

Example 1. What is the test duration for a 50 foot extension of two (2) inch plastic for new business?

From Table 4 test duration for 50 feet of two (2) inch plastic pipe six (6) minutes. From Table 2 the minimum duration for plastic pipe is one (1) hour. Therefore, test duration minimum for this pipeline extension is one (1) hour.

Example 2. What is the test duration for 300 feet of four (4) inch and 500 feet of two (2) inch plastic pipe?

From Table 4 test duration for 300 feet of four (4) inch is 36 minutes and for 500 feet of two (2) inch is 15 minutes for a total of 51 minutes. From Table 2 the minimum test duration for plastic pipe is one (1) hour. Therefore, test duration minimum for this piping system is one (1) hour.

Example 3. What is the test duration for 500 feet of six (6) inch and 300 feet of four (4) inch steel pipe to be operated at 60 psig?

From Table 4 test duration for 500 feet of six (6) inch is two (2) hours and 15 minutes and for 300 feet of four (4) inch is 36 minutes for a total of two (2) hours and 51 minutes. From Table 2 the minimum test duration for steel pipe to be operated at less than 100 psig is one (1) hour. The added test durations for the two pipe segments from Table 4 of two (2) hours and 51 minutes exceeds the minimum required. Therefore, the test duration is two (2) hours and 51 minutes minimum.

Example 4. What is the test duration for a five (5) feet of two (2) inch plastic pipe to be used to repair a damaged pipeline?

From Note 4 under Table 2 the minimum duration is 20 minutes because the pipe being tested meets the three conditions stated, i.e., eight (8) inch or less in diameter, 40 feet or less length, and no joints or fittings other than to attach the testing apparatus.

8. PRESSURE STABILIZATION AND TEMPERATURE EFFECT

Time shall be allowed for the temperature of the pipeline facility and test medium to reach equilibrium which results in pressure stabilization.

Notes: 1. Air can have a temperature of more than 100 °F as it leaves a compressor.

2. If compressed nitrogen is being used, the cryogenic affect will cool the nitrogen as it enters the pipeline facilities being tested. Buried facilities will have stabilized to ground temperature and the temperature effect from the nitrogen injection should be minimal.

To ensure the required test pressure is achieved, the test medium should be injected until the pressure is slightly higher (e.g., 5 or 10 PSIG) than the required test pressure (e.g., 90 PSIG is the required test pressure for a 60 PSIG MAOP distribution main).

The start of the pressure test shall only begin after the pressure has stabilized.

The test is acceptable when the pressure remains above the required test pressure with no pressure loss during the duration of the test.

Note: A pressure decrease due to ambient conditions during the test is acceptable if the pressure returns to the stabilized pressure. For example, it is typical on an overnight test for the pressure to drop slightly and then increase to the stabilized pressure the next day. This is considered an acceptable test. However, if the pressure does not return to the stabilized pressure the test will need to continue until it reaches the stabilized pressure or repeat the test.

9. TESTING REQUIREMENTS FOR CERTAIN APPLICATIONS

The test requirements in this Section for certain applications are exempted from the test requirements in Section 7 unless otherwise stated. Each required test shall be documented in accordance with Section 11.

9.1 Tie-In Joints

Each tie-in joint shall be pressure tested using leak detector solution at operating pressure if the tie-in joint is not included in the pressure test of the pipeline.

9.2 Tapping and Stopping Fittings

Tapping and stopping fittings shall be pressure tested prior to tapping the pipeline.

Note: Tapping and stopping fittings include shortstopps, 3-way tees, full encirclement 3-way tees, spherical 3-way tees, spherical stoppers, full encirclement stopples, line stoppers, line stoppers with bottom out.

Performing a leak test on an untapped tapping or stopping fitting can dent or collapse the pipeline it is installed on. The collapse can occur when there is a significant differential between the system pressure and the intended test pressure for the fitting. A full encirclement type fitting is more apt to cause a problem than a tee type fitting.

For the system design pressures listed in Table 5 a tapping or stopping fitting within the maximum pipe outside diameter (OD) range shall be tested per paragraphs a. and b. below. When a tapping or stopping fitting is to be installed that is outside of the range shown in Table 5 see Exhibit C for the proper test procedure.

a. For a fitting without an outlet connection, such as a T.D. Williamson (TDW) stopple or Mueller line stopper, that is within the range shown in Table 5, leak test the fitting at minimum of 1.5 times the design pressure of the carrier pipe for a minimum duration of 15 minutes. Apply leak detector solution to all exposed joints during the test. Record the results in accordance with Section 11 of this standard.

   Example Test Requirement for Fittings without an Outlet Connection:

   Example 1. What are the test requirements for a 12 inch TDW stopple fitting installed on a 12 inch steel main with a system design pressure of 60 psig?

   From Table 5, for a 60 psig system design pressure the maximum pipe OD allowed is 22 inch. The 12 inch pipeline is within this range which allows the TDW stopple fitting to be tested at a minimum of 90 psig for a minimum of 15 minutes per bullet “a” of this Section. Apply leak detector solution to all joints during the test and record the test results in accordance with Section 11 of this standard.

Example 2. What are the test requirements for a 16 inch TDW stopple fitting installed on a 16 inch steel main with a system design pressure of 200 psig?

From Table 5, for a 200 psig system design pressure the maximum pipe OD allowed is eight (8) inch. The 16 inch pipeline is outside of the allowed range which means that the TDW stopple fitting must be tested in accordance with Exhibit C bullet “a”, i.e., the fitting would be tested at minimum of 100 psig for 15 minutes. Apply leak detector solution to all joints during the test and record the test results in accordance with Section 11 of this standard.

b. For a fitting with an outlet connection, such as a T.D. Williamson 3-way spherical tee or Mueller bottom out, that is within the range shown in Table 5, test the fitting with the new pipeline welded to the fitting outlet in accordance with Section 7 of this standard to establish the MAOP of the new pipeline. Apply leak detector solution to all exposed joints during the test. Record the results in accordance with Section 11 of this standard.

Example Test Requirement for Fittings with an Outlet Connection:

Example 1. What are the test requirements for a 12 inch TDW Spherical 3-way Tee fitting installed on a 12 inch steel main with a system design pressure of 60 psig?

From Table 5, for a 60 psig system design pressure the maximum pipe OD allowed is 22 inch. The 12 inch pipeline is within this range which allows the TDW spherical fitting to be tested as specified according to bullet “a.” of this Section, i.e., leak test the fitting at minimum of 1.5 times the design pressure of the carrier pipe for a minimum duration of 15 minutes. Apply leak detector solution to all exposed joints during the test and record the results in accordance with Section 11 of this standard.

Example 2. What are the test requirements for a 16 inch TDW Spherical 3-way Tee fitting installed on a 16 inch steel main with a system design pressure of 200 psig?

From Table 5, for a 200 psig system design pressure the maximum pipe OD allowed is eight (8) inch. The 16 inch pipeline is outside of the allowed range which means that the TDW spherical fitting must be tested in accordance with bullet “a” in Exhibit C, i.e., the fitting would be tested at minimum of 100 psig for 15 minutes. Apply leak detector solution to all joints during the test and record the test results in accordance with Section 11 of this standard.

Table 5

System Design Pressure (PSIG)	Maximum Pipe OD (Inch)
60	22
99	14
125	12
200	8

9.3 Pre-Fabricated Units, Short Sections of Pipe and Station Piping

For pre-fabricated units, such as block valve settings, regulation and/or measurement settings, cleaner settings, etc., a post installation test may be impractical. These shall have a pre-installation pressure test conducted by maintaining a pressure at or above the test pressure for at least one (1) hour, except that a duration of 15 minutes may be used for pre-fabricated units that will operated at less than 100 PSIG. When the pre-fabricated unit is to have a MAOP that produces a hoop stress that is greater than 30% of SMYS, the test duration shall be at least four (4) hours.

In a Class 1 or Class 2 location, each compressor station, regulator station and measuring station shall be tested to at least Class 3 location test requirements. The test pressure shall be 1.5 times the design pressure and the maximum hoop stress allowed as a percentage of SMYS shall be according to Table 1.

Temporary bypass lines shall be tested according to Section 7, of this standard. Record the results in accordance with Section 11.6.

After installation each tie-in joint shall be leak tested in accordance with Section 9.1.

9.4 Non-Pipe Component

If a component other than pipe is the only item being replaced or added to a pipeline, a pressure test of the component after installation is not required provided that the manufacturer of the component certifies that:

a. The component was tested to at least the pressure required for the pipeline to which it is being added,

b. The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to as least the pressure required for the pipeline to which it is being added, or

c. The component carries a pressure rating established through applicable, e.g., ASME/ANSI, MSS specifications, or by unit strength calculations as described in CFR 49 Part 192.143.

If a non-pipe component does not meet the above criteria the non-pipe component shall be pressure tested in accordance with Section 9.3 of this standard.

After installation each tie-in joint shall be leak tested in accordance with Section 9.1.

9.5 Pre-Tested Pipe

Where pre-tested pipe is used for replacement of short sections of main or transmission line in lieu of on-site pressure testing, the pre-tested pipe shall be tested in accordance with Section 7 of this standard.

After installation each tie-in joint shall be leak tested in accordance with Section 9.1.

See Section 11.6 for test documentation requirements.

9.6 Service Line Connection to the Main or Transmission Line

The connection to the main or transmission line, for new or replacement Company service lines that do not utilize an existing tap hole, shall be included in the test of the service line.

When utilizing an existing tap hole on a replacement service line(s), the service connection to the main, or transmission line shall be tested in accordance with Section 9.1 after being placed in service. The replacement portion of the service line shall be pressure tested prior to the connection to the main or transmission line in accordance with Section 7.

See Section 11.1 for test documentation requirements.

9.7 Test Requirements for Reinstating Service Lines

Services that have been disconnected must be leak tested before reinstating (i.e. being returned to service). A service line is disconnected when any whole or part of a service line is physically disconnected from the gas source. A disconnection may occur due to excavation damage, or for relocation or maintenance purposes.

Shutting off curb valves, squeezing plastic pipe or activation of an excess flow valve alone (i.e., when the piping has not been disconnected) does not constitute disconnection.

A service line that has been disconnected shall be tested with air or inert gas in accordance with Table 2 before the service line is reinstated. The test shall include the portion of the service line from the point of disconnection to the valve on the service riser (e.g. meter valve or stop cock). The final connection of the reinstated service line shall be leak tested at the operating pressure using leak detector solution in accordance with Section 9.1.

If provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service does not need to be tested.

See Section 11.1 for test documentation requirements.

10. LEAKAGE AND MATERIAL FAILURE

10.1 Leakage

After the test medium has been applied and before testing begins, all accessible equipment, components and joints shall be tested with leak detector solution.

If any leaks found cannot be repaired before the testing begins, the test cannot proceed until all leaks are eliminated. A new test for the full duration shall be conducted.

If leakage is detected that is not easily located, an approved leakage detection agent may be injected to help pinpoint the leak. The two approved detection agents are Oil of Wintergreen and Eucalyptus Oil.

Note: Oil of Wintergreen and Eucalyptus Oil are not reliable detection agents, because they depend on an individual's sense of smell. Concentrations required are based on several variables, such as volume of main and wind conditions. Normally only small sections of main are considered for this type of detection. When injecting a detection agent during air or inert gas testing, the oil is to be injected into the main prior to pressurizing. Injection of gas odorant or Freon as a leakage-detecting agent is prohibited.

10.2 Material Failure

If a material (e.g., component, pipe) failure occurs the test must be stopped.

A failed component must be replaced with an equivalent.

Failed pipe must be repaired or replaced using the applicable Company gas standard. For pipe repair refer to GS 1730.010 “Repair of Transmission Lines” or GS 1714.020, “Leakage – Distribution Pipe Repair.”

Material failures shall be reported according to GS 1652.010 “Investigation of Failures.”

10.3 Joint Failure

If a joint failure occurs the test must be stopped.

When a failure occurs at a plastic fusion joint the joint shall be cut out and replaced. In addition, the person that performed the joint may need to be re-qualified in accordance with ON 16-03 “Plastic Joint Failure During a Pressure Test – Notification and Evaluation.”

When a failure occurs at a weld it shall be repaired or replaced in accordance with the Welding Manual.

When a failure occurs at a mechanical fitting (e.g., component) refer to Section 10.2 of this standard.

Joint failures shall be reported according to GS 1652.010 “Investigation of Failures.”

11. RECORDS

A test record is required for each of the following pressure tests.

- Main, transmission line and service line (e.g. Section 7, Table 2)
- Tie-in joint (Section 9.1)
- Tapping and stopping fittings (Section 9.2)
- Pre-fabricated units, short sections of pipe and station piping (Section 9.3)
- Pre-test pipe (Section 9.5)
- Service line connection to main and transmission line (Section 9.6)
- Reinstatement of service lines (Section 9.7)

Pressure tests shall be documented as specified in the following sections by the Company’s Representative.

11.1 Record Requirements for Service Lines Smaller than 3 Inch

Except for steel service lines that are stressed a 20% or more of SMYS, the service line test pressure record shall be entered into the applicable electronic database, such as WMS or Maximo. Test pressure and duration shall be recorded.

Steel service lines that are stressed to 20% or more of SMYS must meet the record requirements of Section 11.2.

11.2 Record Requirements for Mains, Transmission Lines, Stations, and Service Lines 3 Inch and Larger

11.2.1 Required Pressure Test Information

The following pressure test information shall be documented.

a. Company name.
b. Responsible employee.
c. Name of test company or contractor, if applicable.
d. Test pressure.
e. Medium used.
f. Test duration.
g. Leaks and failures noted and their disposition.
h. Work order number.

11.2.2 Pressure Test Record Forms

One of the following pressure test record forms shall be used to document each pressure test performed. Form GS 1500.010-3 can be used to record more than one type of test, e.g., a pipeline test and a leak test on a tie-in joint.

a. GS 1500.010-1 “Pipeline Pressure Test Data” (4 inch round label)
b. GS 1500.010-2 “Station Pressure Test Data” (4 inch round label)
c. GS 1500.010-3 “Pipeline, Station, Leak Test Data” (full size sheet)

Examples of completed forms are shown in Exhibit A.

11.2.3 Pressure Test Record Requirements

A complete test record shall be included in the work order packet/WMSDocs for each test performed and shall include the following.

a. For a test duration of one (1) hour or less.

   i. Completed test form GS 1500.010-1, -2 or -3.

b. For a test duration of more than one (1) hour.

   i. Completed test form GS 1500.010-1, -2 or -3, and

      a. Recording chart, or

b. Printed digital gauge receipt.

The recording chart and/or printed digital gauge receipt shall be attached to the test form used.

Form GS 1500.010-1 and GS 1500.010-2 (4 inch round labels) are designed to be affixed to the back of a recording chart.

When it is not possible to affix the test form to the recording chart or printed digital gauge receipt the following information shall be written on the back of the recording chart or receipt: test date, Company, work order and name of Company's Representative.

All test forms, recording charts and printed digital gauge receipts shall be included in the Work Order packet/WMSDocs.

11.3 Additional Record Requirements for Multiple Pressure Tests

If multiple pressure tests are conducted for subsections of a project that are placed in service at different times, each pressure test document shall identify the section of the project that was pressure tested with the following information.

a. Physical location of test (e.g. street address/street intersection/other or end of main).

b. Test performed on __ ' Footage of __ "Diameter pipe, (e.g. list all subsection included in test by footage and diameter).

c. Date pressure test performed.

The pipe segments(s) tested corresponding to each separate record form shall be indicated on a sketch of the project.

11.4 Record Requirements for Tapping and Stopping Fittings and Tie-in Joints

All pressure test data for tapping and stopping fittings, and tie-in joints tested at operating pressure using leak detector solution, shall be recorded on the proper pressure test form. A description and location of each fitting or tie-in joint shall be included on the form.

11.5 Record Requirements for Pre-fabricated Units, Short Sections of Pipe and Station Piping

All pressure test data for pre-fabricated units, short sections of pipe and station piping shall be recorded on the proper test form. A description and location of each item being tested shall be included on the form.

11.6 Record Requirements for Pre-tested Pipe and Temporary Bypass Piping

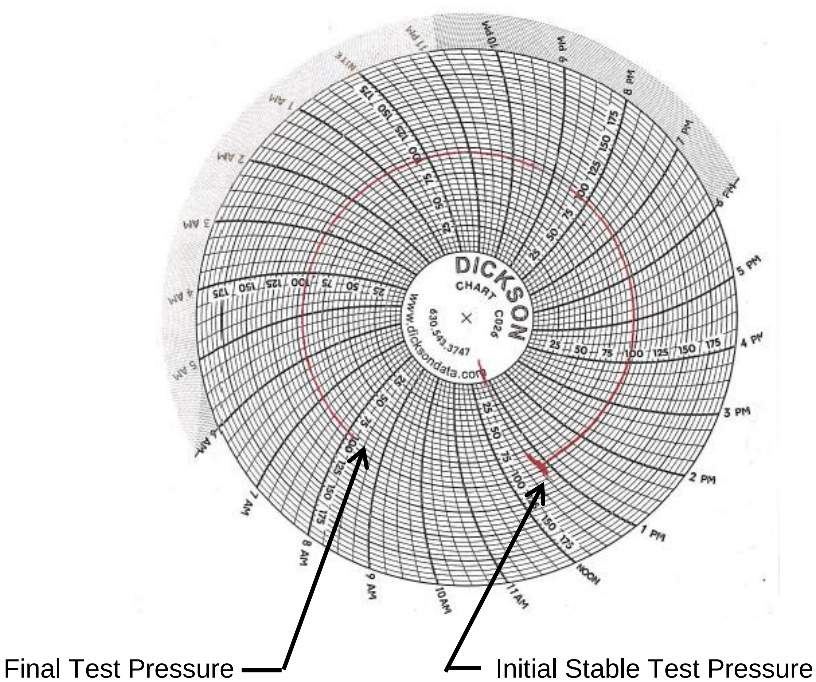
Documentation of the pressure test shall be retained and referenced on the appropriate job orders and/or electronic database.

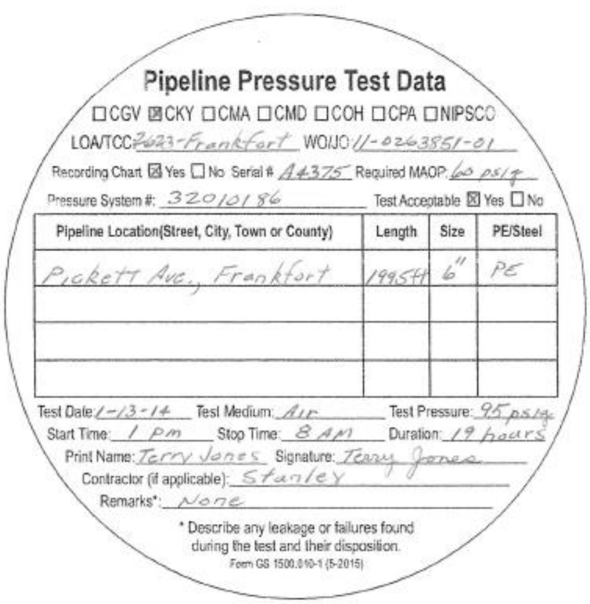
11.7 Records Retention

Pressure test records shall be retained for the useful life plus ten (10) years of the pipeline to confirm establishment of maximum allowable operating pressure (MAOP).

EXHIBIT A
(1 of 5)

Recording Chart & Test Record Label for Pipeline Test
Test Duration 19 Hours
1 P.M. to 8 A.M.





Pipeline Pressure Test Data

☐CGV ☒CKY ☐CMA ☐CMD ☐COH ☐CPA ☐NIPSCO

LOA/TCC: 2623-Frankfort WO/JO: 11-0263851-01

Recording Chart ☒ Yes ☐ No Serial #: A4375 Required MAOP: 60 psig

Pressure System #: 32010186 Test Acceptable ☒ Yes ☐ No

Pipeline Location(Street, City, Town or County)	Length	Size	PE/Steel
Pickett Ave., Frankfort	1995ft	6"	PE

Test Date: 1-13-14 Test Medium: Air Test Pressure: 95 psig

Start Time: 1 pm Stop Time: 8 AM Duration: 19 hours

Print Name: Terry Jones Signature: Terry Jones

Contractor (if applicable): Stanley

Remarks*: None

* Describe any leakage or failures found during the test and their disposition.

Form GS 1500.010-1 (5-2015)

NiSource
Distribution Operations

Gas Standard

Effective Date: 06/01/2016	**Pressure Testing**	Standard Number: **GS 1500.010**
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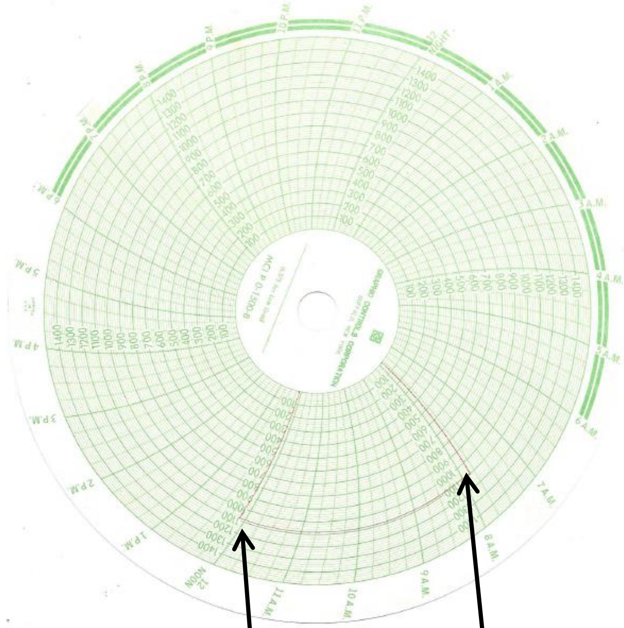
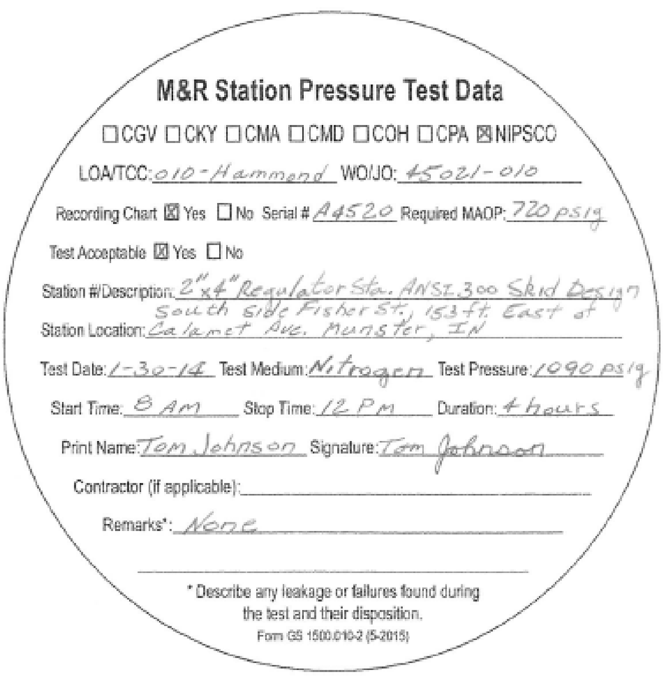
EXHIBIT A
(2 of 5)

Recording Chart & Test Record Label for Regulator Station Test
Test Duration 4 Hours
Test Pressure 1090 psig



Initial Stable Test Pressure — **Final Test Pressure**



M&R Station Pressure Test Data

☐CGV ☐CKY ☐CMA ☐CMD ☐COH ☐CPA ☒NIPSCO

LOA/TCC: 010-Hammond WO/JO: 45021-010

Recording Chart ☒ Yes ☐ No Serial # A4520 Required MAOP: 720 psig

Test Acceptable ☒ Yes ☐ No

Station #/Description: 2"x4" Regulator Sta. ANSI 300 Skid Design

Station Location: South side Fisher St., 153 ft. East of Calumet Ave. Munster, IN

Test Date: 1-30-14 Test Medium: Nitrogen Test Pressure: 1090 psig

Start Time: 8 AM Stop Time: 12 PM Duration: 4 hours

Print Name: Tom Johnson Signature: Tom Johnson

Contractor (if applicable): ______

Remarks*: None

* Describe any leakage or failures found during the test and their disposition.

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**EXHIBIT A
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**Full Size Test Record Form with Tie-in Joint Example
Test Duration 15 Minutes
Test Pressure 50 psig**

Pressure Test Form (Retain Permanently)

Company: ☐CGV ☐CKY ☐CMA ☐CMD ■COH ☐CPA ☐NIPSCO

LOA/TCC: 0822-Columbus Pressure System No. 34100165 WO/JO: 13-0086655-00

Recording Chart: ☐Yes* ■No Recorder Serial No.______ Required MAOP: ______

Pipeline or Station Pressure Test **Test Acceptable: ☐Yes ☐No**

Station Number: ______ Minimum Test Pressure Required: ______

Description of Station: ______

Location of Station: ______

Pipeline Description

Location of Pipeline(s)	City, Town, County, etc.	Length	Size	PE or Steel

Start Date: ______ Start Time: ______ ☐AM ☐PM Actual Test Pressure: ______ Test Medium: ☐Air ☐Nitrogen

Stop Date: ______ Stop Time: ______ ☐AM ☐PM Actual Test Duration: ______ ☐Water ☐Natural Gas

Describe any leaks or failures that occurred and explain their disposition: ______

Additional Comments: ______

Print Name: ______ Signature: ______ Contractor (if applicable): ______

Leak or Pressure Test (tie-in joint, pressure control fitting, etc.) **Test Acceptable: ■Yes ☐No**

Description (tie-in joint, end cap, control fitting, etc.): 6" electrofusion coupling tie-in for 6" main extension

Location: West side of James St. 145 feet north centerline of Mound St.

Start Date: 01-03-14 Test Medium: ☐Air ☐Nitrogen ☐Water ■Natural Gas System or Test Pressure: 50 psig

Start Time: 3:00 ☐AM ☒PM Stop Time: 3:15 ☐AM ☒PM Actual Test Duration: 15 minutes

Describe Leak(s) and Disposition of Leak(s): None

Additional Comments: ______

Print Name: Terry Richards Signature: Terry Richards Contractor (if applicable): Miller

* Write WO/JO number, test medium, test pressure and date on back of recording chart, if used, and attach to this form before submittal.

Note: Record data for additional tie-in tests on reverse side.

GS 1500.010-3 (09/2015)

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EXHIBIT A
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Example of a print out from an electronic pressure recording gauge. Reports shows pressure held steady at 93 psig for required 6 hour minimum.

Test Duration 6 Hour
Test Pressure 93 psig

Printed Receipt

TEST ID#:	130225771011
USER PIN:	9328
TEST START DATE:	08/29/14
TEST START TIME:	17:43
TEST END DATE:	08/30/14
TEST END TIME:	00:43 KIC3
TEST LENGTH:	07:00:00
TEST TYPE:	HIGH PRESSURE
INITIAL PRESS:	94 Psi
FINAL PRESS:	93 Psi
DEVIATION:	- 1 Psi
SERIAL #:	051808
CALIB DATE:	12/17/13
CALIB DUE DATE:	12/17/14

Signed:

TEST TIME	INITIAL	DATA LOG CURRENT	DEV
17:43	94	94	0
17:58	94	94	0
18:13	94	93 -	1
18:28	94	93 -	1
18:43	94	93 -	1
18:58	94	93 -	1
19:13	94	93 -	1
19:28	94	93 -	1
19:43	94	93 -	1
19:58	94	93 -	1
20:13	94	93 -	1
20:28	94	93 -	1
20:43	94	93 -	1
20:58	94	93 -	1
21:13	94	93 -	1
21:28	94	93 -	1
21:43	94	93 -	1
21:58	94	93 -	1
22:13	94	93 -	1
22:28	94	93 -	1
22:43	94	93 -	1
22:58	94	93 -	1
23:13	94	93 -	1
23:28	94	93 -	1
23:43	94	93 -	1
23:58	94	93 -	1
00:13	94	93 -	1
00:28	94	93 -	1
00:43	94	93 -	1

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**EXHIBIT A
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Full Size Test Record Form with Pipeline and Tie-in Joint Example

Pressure Test Form (Retain Permanently)

Company: ☐CGV ☐CKY ☐CMA ☐CMD ☐COH ■CPA ☐NIPSCO

LOA/TCC: 2421-York Pressure System No. 37001025 WO/JO: 11-0231325-02

Recording Chart: ☐Yes* ■No Recorder Serial No.______ Required MAOP: 60 psig

Pipeline or Station Pressure Test **Test Acceptable:** ■Yes ☐No

Station Number: ______ Minimum Test Pressure Required: 90 psig

Description of Station: ______

Location of Station: ______

Pipeline Description

Location of Pipeline(s)	City, Town, County, etc.	Length	Size	PE or Steel
Wooster Dr.	Dover	354 ft.	2"	PE
Willapa Dr.	Dover	404 ft.	2"	PE

Start Date: 02-15-12 Start Time: 3:50 ☐AM ■PM Actual Test Pressure: 95 psig Test Medium: ■Air ☐Nitrogen

Stop Date: 02-15-12 Stop Time: 4:50 ☐AM ■PM Actual Test Duration: 1 hour ☐Water ☐Natural Gas

Describe any leaks or failures that occurred and explain their disposition: None

Additional Comments: ______

Print Name: John Jones Signature: John Jones Contractor (if applicable): ______

Leak or Pressure Test (tie-in joint, pressure control fitting, etc.) **Test Acceptable:** ■Yes ☐No

Description (tie-in joint, end cap, control fitting, etc.): 2" electrofusion coupling tie-in for 2" main extension

Location: Northeast side of Willapa Dr. 45 southeast centerline of Danielle Dr.

Start Date: 02-17-12 Test Medium: ☐Air ☐Nitrogen ☐Water ■Natural Gas System or Test Pressure: 45 psig

Start Time: 9:00 ■AM ☐PM Stop Time: 9:15 ■AM ☐PM Actual Test Duration: 15 minutes

Describe Leak(s) and Disposition of Leak(s): None

Additional Comments: ______

Print Name: John Jones Signature: John Jones Contractor (if applicable): ______

* Write WO/JO number, test medium, test pressure and date on back of recording chart, if used, and attach to this form before submittal.

Note: Record data for additional tie-in tests on reverse side.

GS 1500.010-3 (09/2015)

EXHIBIT B
(1 of 3)

<u>Method to Determine Inert Gas Requirements</u>

The following method, along with attached graph provides a means of estimating the number of 226 Std. cu. ft. bottles at 2,200 PSIG of nitrogen required for a given test pressure and piping volume. This method is based on the formula:

N = BV

where:

N = number of bottles required

B = factor from graph (Exhibit B) (number of bottles per cu. ft. of piping system). Enter graph at the desired test pressure "P" in PSIG and read B.

V = volume of piping system in cu. ft.

Four (4) requirements must be met when using the above formula:

a. If air pressure is available, the piping system should first be pressurized to at least 90 PSIG with air. It is advisable to check for any leakage. The nitrogen bottles are used to pressurize the system from the level reached with air to the desired test pressure. If air pressure is not available or if the volume of the system is small resulting in it not being practicable to first pressurize the system with air, then nitrogen bottles may be used to pressurize the system.

   Note: The graph in Exhibit B shows two curves, one for starting at an initial pressure of 0 psig and one for 90 psig.

b. The bottles are to be connected successively, one at a time, discharged and then shut off, before connecting and discharging the next bottle.

c. Use the standard 8 1/4 inch I.D. x 51 in. long bottle. This contains 226 Std. cu. ft. of nitrogen at 2200 PSIG when full.

d. The formula is based on a constant temperature process. Due to throttling of the nitrogen, some temperature drop will occur.

Example A: 2500 ft. of 2 in. nominal x .154 in. wall steel pipe (2.375 in. O.D. x 2.067 in. I.D.) to be tested to 750 PSIG

$$V = \frac{\pi d^2 L}{576}$$

where:

$\pi =$ 3.14

EXHIBIT B
(2 of 3)

d = Internal Diameter (inches)

L = Length of Pipe (feet)

$$V = \frac{\pi(2.067)^2(2500)}{576} = 58.2\,\text{cu. ft.}$$

Enter graph at 750 PSIG and read on the (90 PSIG initial) curve:

B = 0.248 Bottle/cu. ft.

N = 0.248 x 58.2 = 14.4

Requires 15 bottles

Note: If air compressor was not available, with 0 initial pressure:

B = 0.277

N = 0.277 x 58.2 = 16.1

Requires 17 bottles

Example B: New regulator station piping to be tested to 750 PSIG. Calculations show the piping volume is 150 cu. ft., including the measurement runs, regulator settings, headers, and interconnecting piping.

V = 150 cu. ft.

Enter graph at 750 PSIG and read on the (90 PSIG initial) curve:

B = 0.248 bottle/cu. ft.

N = 0.248 x 150 = 37.2

Requires 38 bottles

Note: If air compressor was not available, with 0 initial pressure:

B = 0.277

N = 0.277 x 150 = 41.6

Requires 42 bottles

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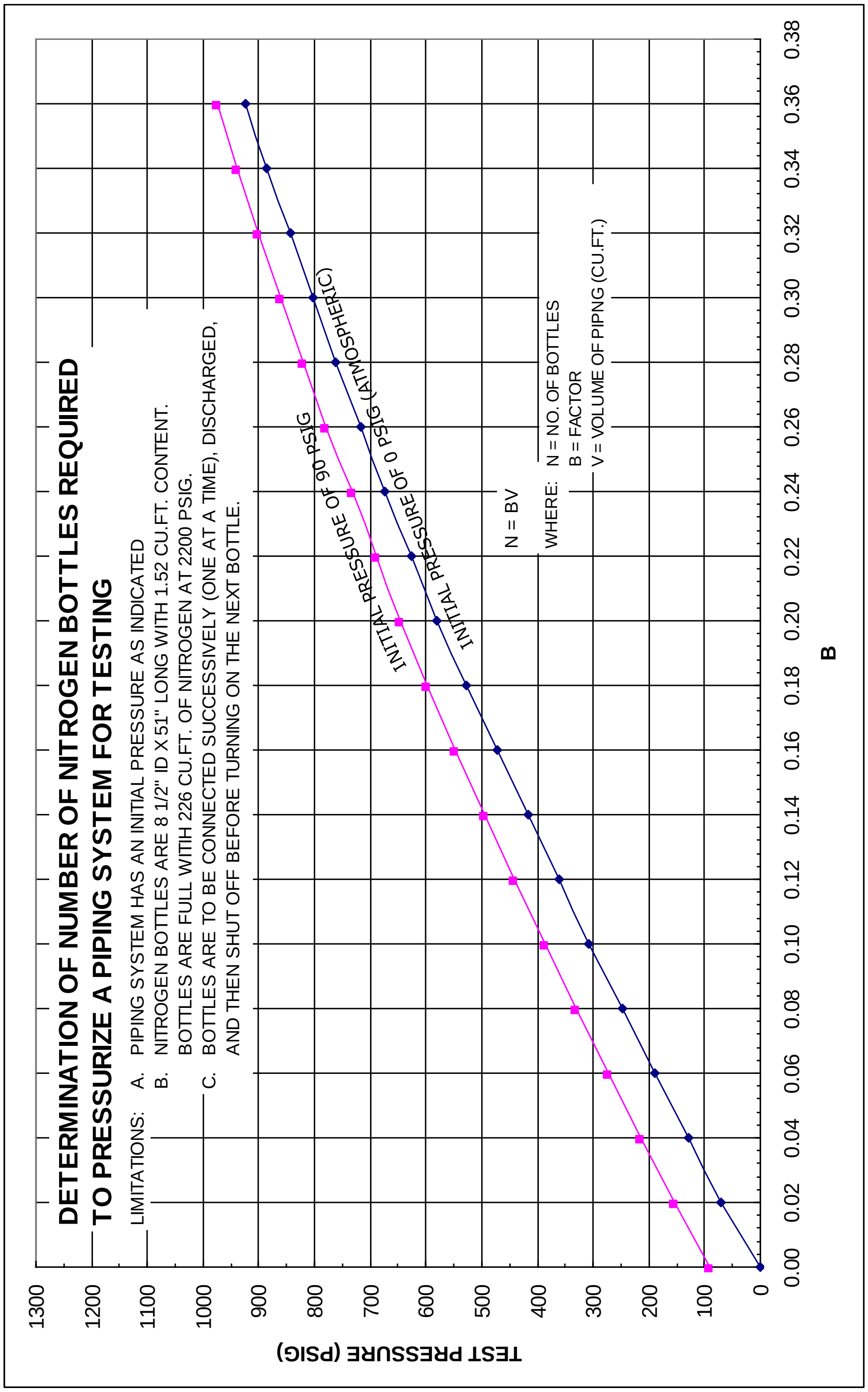

EXHIBIT C
(1 of 2)

Leak Test Procedure for Pressure Control Fittings

Pressure control fittings installed on pipelines that are outside the limits shown in Table 5 shall be tested as follows.

a. For fittings without an outlet connection, such as a T.D. Williamson stopple or Mueller line stopper, leak test the fitting at a minimum of 100 psig. The leak test must be maintained for a minimum duration of 15 minutes. Apply leak detector solution to all exposed joints during the test. Record the results of all tests per Section 11.4 of this standard.

b. For a fitting with an outlet connection, such as a T.D. Williamson 3-way spherical tee or Mueller bottom out test the fitting prior to attaching the new pipeline to it. To accomplish this a pup of pipe and a weld cap can be welded to the outlet of the fitting. The pup of pipe used shall have been previously strength tested according to Section 9.3 of this standard. The pressure used to leak test the pressure control fitting with the pup of pipe attached shall not be greater than the maximum current operating pressure to test pressure differential allowed in Table C1. The leak test must be maintained for a minimum duration of 15 minutes. Apply leak detector solution to all exposed joints during the test. If the wall thickness of the pipe is not shown in Table C1 use the next thinner pipe wall thickness listed. After the leak test is completed, remove the weld cap from the pup of pipe on the fitting and complete the tie-in weld to the newly installed pipeline that has been previously strength tested per Section 7 of this standard. The tie-in joint shall be leak tested per Section 9.1. Record the results of all tests per Section 11.4 of this standard.

EXHIBIT C
(2 of 2)

Table C1

Pipe OD (Inches)	Pipe Wall Thickness (Inches)	Maximum Leak Test to Operating Pressure Differential (psig)	Pipe OD (Inches)	Pipe Wall Thickness (Inches)	Maximum Leak Test to Operating Pressure Differential (psig)
2.375	0.109	4986	14	0.219	185
2.375	0.125	7627	14	0.312	544
2.375	0.154	4245	14	0.375	953
2.375	0.218	5835	16	0.219	124
3.5	0.120	2029	16	0.250	185
3.5	0.156	4554	16	0.281	264
3.5	0.216	4053	16	0.312	362
3.5	0.300	5486	16	0.375	634
4.5	0.156	2099	20	0.250	94
4.5	0.188	3729	20	0.312	184
4.5	0.237	7643	20	0.375	321
4.5	0.337	4850	20	0.500	772
6.625	0.188	1136	22	0.312	138
6.625	0.219	1814	22	0.375	241
6.625	0.280	3864	22	0.500	577
6.625	0.432	4267	24	0.250	54
8.625	0.188	508	24	0.312	106
8.625	0.219	809	24	0.375	185
8.625	0.250	1213	24	0.500	443
8.625	0.277	1660	30	0.312	54
8.625	0.322	2636	30	0.375	94
8.625	0.500	10307	30	0.438	150
10.75	0.188	260	30	0.500	225
10.75	0.219	414	36	0.375	54
10.75	0.250	619	36	0.438	87
10.75	0.365	1969	36	0.500	129
12.75	0.219	246			
12.75	0.250	368			
12.75	0.375	1268			

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Distribution Operations

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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192 Subpart J

1. GENERAL

This procedure provides the requirements and guidance to plan and perform a hydrostatic pressure test on newly constructed and existing in-service pipelines. For pneumatic pressure testing procedures refer to GS 1500.010 "Pressure Testing" and specifically to Section 6 "Test Medium" to determine is a hydrostatic pressure test is required due to the stress level the pipe will be subjected to during the test.

The following provisions apply to hydrostatic pressure tests.

a. Prior to being placed in service, the Company will pressure test all new, replaced, relocated, disconnected and previously abandoned mains, transmission lines, service lines, tie-in joints and attached gas carrying facilities by a leak test and/or strength test to:

   i. Eliminate all potentially hazardous leaks, and

   ii. Establish the maximum allowable operating pressure (MAOP) in accordance with GS 1660.010 or GS 1660.010(PA) "Maximum Allowable Operating Pressure."

b. The Gas Transmission and M&R Design group, and Major Projects or responsible Engineering group will determine when hydrostatic pressure testing will be used.

c. All hydrostatic pressure test activities shall comply with Company Environmental requirements and permits.

d. Hydrostatic pressure test levels specified shall at a minimum comply with the requirements outlined in Section 5. Maximum and minimum test pressures and extent of the test section shall be provided in the project drawings, or by the Company's Representative.

e. All ball valves internal to the system being tested shall be tested in the half-open position to eliminate the possibility of damage due to a differential across the valve seats.

f. For transmission lines, a pre-installation leak test is recommended for special construction such as inserts; river, highway, railroad, and bridge crossings; and measurement/regulator station piping. The minimum test pressure for the leak test, shall be 100 psig, but no more than a pressure that would produce a stress level of 20% SMYS of the pipeline being tested.

g. In accordance with Section 4 a written test plan is required. Prior to beginning a hydrostatic pressure test the test plan shall be reviewed with all personnel involved in the testing including Section 3 of this standard. If any changes are made to the test plan the changes shall be communicated to all personnel affected by the changes.

h. In-service Transmission Lines: As designated by IMP 02-001 (Columbia), “Assessment Method Selection” and IMP 04-500 (NIPSCO), “Pressure Testing” the Company shall hydrostatic pressure test existing pipelines as follows.

   i. Perform an integrity assessment on a section of the pipeline.

   ii. Confirm maximum allowable operating pressure (MAOP).

   iii. Uprate the maximum allowable operating pressure (MAOP) for a pipeline.

For the purpose of this standard unless otherwise noted the use of the word test, testing, tested shall mean hydrostatic pressure test.

2. RESPONSIBILITY

It is the responsibility of the Company’s Representative, whether employee or contractor, to ensure that a hydrostatic pressure test is conducted in accordance with this standard and that activities are in compliance with the written test plan. The Company’s Representative shall be present when the test is started and when the test ends, and shall record the test results except for fabricated sections tested off site. The test shall be repeated if deemed necessary by the Company’s Representative.

3. SAFETY DURING TESTING

The following safety precautions shall be followed during the testing procedure.

a. All practical steps shall be taken to keep the public outside the testing area (test header piping and all pressurized exposed piping) until the test is completed. Use caution signs, barriers, patrols, and guards as necessary to restrict access to the testing areas.

b. Provide fire extinguishers, breathing apparatuses, safety harnesses, ear protection, gas detectors, and other equipment as appropriate.

c. Monitoring of road crossing and the pipeline right-of-way for pedestrian congregation shall be required for the following conditions.

   i. When a pipeline of 720 psig design or higher is being tested, or

   ii. For any test in which the stress in the pipeline will exceed 50% of the specified minimum yield strength (SMYS) of any component in the system.

d. A communication plan shall be established for informing the public, governmental agencies, and any other stakeholders of testing plans and safety considerations when it is reasonable to expect the testing activities would affect these stakeholders. A communication plan is especially important in the following situations.

   i. For testing that is being performed in densely populated areas.

   ii. For people who live or work within 100 feet of a transmission pipeline shall be informed prior to a hydrostatic pressure test.

   iii. Any planned venting of natural gas from the pipeline prior to testing should be communicated to the public and authorities to prevent unnecessary alarm.

e. A reliable transportation and communication system shall be in place during the test whereby all personnel directly involved in the test shall be able to report test status or problems that develop.

f. The Company's Representative has the authority to suspend the test if an unsafe condition exists or develops.

g. When testing in high exposure areas consider scheduling at a time to minimize public and noise exposure, and limiting the length of the test section to minimize potential hazards.

h. Testing against a temporary stopping device, such as a "Mueller" plug, "TD Williamson" stopple, or bag, is prohibited. Testing against a closed main line valve is also prohibited.

i. Mechanical compression caps and couplings shall not be used.

j. All test connections, hoses, and fittings shall be exposed and of adequate rating for the test pressure. Hoses shall be restrained during testing.

k. Temporary welds shall be nondestructively tested when performing hydrostatic pressure tests on transmission lines.

l. Prior to beginning the test check the components that are not a part of the pipeline section being tested, but are part of the testing system equipment that will be exposed to the test pressure to confirm they are rated for the test pressure and are in good working order.

m. The hazards of testing exposed piping should be considered, regardless of the test medium. The hazards associated with testing unburied pipe are diminished when using water as a medium.

n. It is recommended to backfill as much as practical before testing.

o. During hydrostatic testing the test header shall be sufficiently blocked to prevent movement or pull out.

p. For a hydrostatic pressure test duration greater than one (1) hour, a tag to indicate the pipeline is under pressure shall be attached to all exposed segments of the pipeline under test. The tag should be attached prior to pressurizing the pipeline and removed upon completion of the test.

q. During the test, all personnel shall be kept clear of the pipeline and test equipment under hydrostatic pressure. Those performing the test shall be near the piping only when necessary and there shall be no work on or around the piping system during the test when the hydrostatic pressure is being relieved.

r. Before any fittings are loosened or removed on the pipeline under test, the test medium shall be fully relieved to atmosphere through a valve. Caution shall be taken to prevent damage to the surrounding area as the pressure is being relieved to atmosphere. **Personnel involved with the test** shall be notified after the hydrostatic pressure in the pipeline has been fully relieved.

s. Personnel operating the valve that controls the relief of the hydrostatic pressure shall wear the appropriate personal protective equipment (PPE).

4. TEST PLANNING AND WRITTEN TEST PLAN

4.1 General

Prior to each test a project specific written test plan shall be developed. The test plan shall include the following.

a. Reason and purpose for the test.

b. Determining factor (e.g., required by code, volume of test medium needed, etc.) used to conduct a hydrostatic test.

c. The safety procedures to be followed, see Section 3.

d. Environmental protocols to be followed.

e. Public safety zone clearance for all test header piping and all pressurized exposed piping.

f. Safety zone clearance for all pumps, deadweight testers, and test buildings.

g. List of line pipe and fittings included in test and their pressure ratings.

h. List of test piping and fittings included in the test and their pressure ratings.

i. List of all equipment needed, including calibration requirements.

j. Rated or calculated % SMYS at the maximum test pressure for the pipe and fittings, see Section 4.2.

k. The extent of system to be tested, length and boundaries of each test section and method of isolation.

l. Elevation changes along the system.

m. The volume of water needed, see Appendix B.

n. The source of water and water testing requirements, see Sections 4.4 and 8.3.

o. Water injection location(s).

p. Unintentional release of test water.

q. The pressure and duration of the test, see Section 5.

r. The location of the test section where test instruments shall be placed.

s. Project specific cleaning requirements, see Section 8.4.

t. Pipeline fill requirements, see Section 9.1.

u. Dewatering and drying of the pipeline, see Section 9.9 and 9.10.

v. Water disposal, see Section 9.11.

w. Drawings or schematics showing the placement and configuration of all testing and test recording operations.

x. List of all stakeholders to be notified prior to and after the test is complete.

y. When hydrostatically testing in-service pipelines, include risk assessment and failure contingency plans, see Section 4.6 and spike test, Section 10.

Operational considerations, the project scope and/or elevation changes of the pipeline may require the pipeline to be tested in multiple sections. The extent of test sections shall be outlined on project specific drawings. Each section should have designated fill locations, vent points and test points.

The test plan should be prepared by the Company and/or the project Contractor depending on project scope. Hydrostatic pressure testing may not proceed until the proposed test plan is approved by the Engineering, Major Projects or Gas Transmission and M&R Design group responsible person.

4.2 Elevation Variations – Determining Test Segments

Differences in elevation should be considered when planning the test to be certain that higher elevations are adequately tested and that piping in low elevation is not exposed to pressures that would cause them to yield. Calculations to determine pressure changes due to elevation can be made using a test gradient (T_G). The T_G is based on an increase of 0.433 psig in hydrostatic pressure for every foot of elevation decrease. The T_G is calculated by the following formula:

$$T_G = \left(elevation\ change\ \times 0.433 \frac{psig}{ft} \right)$$

The maximum pressure (P_{max}) can be calculated by adding the T_G to the minimum pressure (P_{min}).

$$P_{max} = P_{min} + T_G$$

All pressure readings shall be related to the highest point in the test section to establish the minimum test pressure. Maximum test pressure at the lowest point shall also be established to determine that maximum allowed stress levels have not been exceeded. An example elevation calculation is contained in Exhibit B.

Engineering should consider the pipeline design/components, operations/repair history, and vintage prior to selecting a maximum pressure stress level. Depending on the differences of elevation along the pipeline, the maximum stress level selected for the pressure test could have a large effect on the length of the test sections.

4.3 Environmental

Environmental personnel should be contacted for environmental guidance before hydrostatically testing any pipeline. All hydrostatic test operations shall be in compliance with Company Environmental specifications. Environmental personnel shall specify all necessary permits that shall be obtained from governmental agencies for obtaining and discharging test water, and suitability of water.

A wastewater permit is normally required to discharge test water into surface waters, storm sewers, or sanitary sewers. The contents of the permit may vary from state to state, and will require different water sample analyses to be conducted and different forms of filtration of the discharge water. Such permits may require three (3) to six (6) months for approval. Therefore, Environmental personnel shall be contacted as far in advance as possible when water will be used as the test medium.

4.4 Water Source

During the project planning phase, the source of water for the pressure test shall be determined. Treated water (water that has undergone treatment for use in industrial and/or drinking applications) is preferred for testing. If treated water is unavailable, the water may be taken from streams or other bodies of water. It shall be taken in such a manner to minimize harm to the ecology, or aesthetic values of the area. Agricultural runoff is not recommended for test water as it can contain high levels of nitrates and phosphates, which can promote biological activity.

4.5 Test Manifold Design

Ensure public safety with the design of the manifold. Use only components that are rated at or above the maximum specified test pressure.

4.6 In-Service Pipelines – Additional Planning Considerations

When the hydrostatic pressure test is to be performed on pipelines that have been in-service, additional planning is required to address operational requirements, pipeline operating history, and vintage design/construction. When testing in-service pipelines the test plan shall include risk assessment and failure contingency plans. Also refer to Section 5 in GS 5500.300 “Uprating – Preliminary Investigation.”

A detailed review of the pipeline to be tested shall be performed. The review of in-service pipelines shall consider the following.

a. System operational requirements and outage scheduling.
   i. Length of time pipeline will be out of service.
   ii. Alternative gas supply requirements (liquid or compressed natural gas bottles, by-passes, etc.).
   iii. Scheduled customer interruptions.
b. The design and strength of piping, fittings, taps, and valves.
   i. The outside diameter, wall thickness, grade, seam type, and pressure rating of piping and components should be reviewed to ensure they meet the minimum test pressure requirements. To meet test objective, components that do not have adequate strength to withstand the hydrostatic pressure test shall be cut out and replaced prior to testing.
   ii. The pressure of the hydrostatic test performed at the pipe mill, if known should be considered when selecting the test pressure. If the mill test pressure is unknown the probable mill test pressure may be considered. Known mill test pressure indicates the maximum stress level that the pipe has been subjected to and should not be exceeded when practical.
   iii. All taps and associated valves, including those abandoned, shall be reviewed to verify they are rated to withstand the desired test pressure.
   iv. The ability of piping, valves, fittings, bends, and any connections to pass cleaning, fill, and dewater pigs shall be evaluated. Diameter changes in the pipeline may also limit the pigging process. Any component that is determined to potentially impede a cleaning pig in the pipeline shall be removed. Consideration should be given to modifying the pipeline for inspection by a smart pig.
c. Vintage construction and fabrication methods
   i. The pipeline construction and fabrication should be reviewed to assess if any vintage methods that could affect the hydrostatic pressure test exist. If found, engineering should review the data and determine if removal is necessary. Items to review for include the following.
      1. Mitered welds.
      2. Wrinkle bends.

3. Mechanical fittings and couplings.
4. Bell and Spigot pipe joints.
5. Field fabricated fittings.
6. Oxy-Acetylene girth welds.
7. Puddle-welds.
8. Patches.

d. Current and historical pipeline operating and maintenance data including the following.

i. Review maintenance records to identify if there is any corrosion, leak, manufacturing/construction defect, stress corrosion cracking, or other damage history that shall be addressed prior to testing.

ii. All available data related to prior hydrostatic pressure test failures, leakage surveys, patrols, valve maintenance, in-line inspection, and cathodic protection should be reviewed to identify areas that may have the potential for test failures. Areas of concern should be assessed prior to testing. A leak survey shall be performed if one has not been done in the past 12 months.

iii. Repairs, stopple fittings, and other modifications that have been made on the pipeline should be reviewed for expected integrity at the anticipated test pressure. Any component identified as having a possibility to leak or fail during testing shall be cut out and replaced prior to the pressure test.

e. When the hydrostatic pressure test is intended to be an integrity assessment as part of the Company’s Integrity Management Plan, the desired reassessment interval should be considered when determining the test pressure.

For sections of the pipeline identified as requiring assessment and/or replacement, additional engineering, procurement, environmental, and operational planning will be required.

5. HYDROSTATIC TEST PRESSURE AND DURATION

Hydrostatic test pressure and minimum duration shall meet at a minimum the requirements in Table 1.

Table 1

Test Pressure and Duration for Hydrostatic Testing		
Design Stress Level	**Test Pressure (PSIG)**	**Minimum Duration (Hours)**
Steel Pipelines: Greater than or equal to 100 psig and less than 30% SMYS	1.5 times MAOP	1
Steel Pipelines: 30% SMYS or greater	1.5 times MAOP	8

1. For new construction the maximum allowed hoop stress in the pipe during the test is 110% SMYS when the test medium is water. Add comment for in-service pipe.
2. For in-service pipe the mill test pressure shall not be exceeded. Need guidance on procedure when mill test pressure is not known.

5.1 Test Pressure Limitations for Flanged Fittings and Valves

Hydrostatic pressure tests on flanged fittings and valves shall not exceed the maximum test pressure outlined in Table 2.

Table 2

Test Pressure Limitation for Flanged Fittings and Valves		
Valve Class or Class Designation (ANSI)	**Working Pressure[1] (psig)**	**Maximum Test Pressure[2] (psig)**
150	285	450
300	740	1125
400	990	1500
600	1480	2225
900	2220	3350

1. Maximum working pressure ratings for flanged-end, gate, plug, ball and check valves @ 100ºF. Higher temperatures will de-rate this number.

2. Pressures shown are maximum pressures rounded up to the next 25 psig increment. If the maximum test pressure may be exceeded, valves and fittings may need to be cut-in after testing, or the next valve or fitting class may be used, or the valve manufacturer can be consulted to determine if the brand of valve in

use has a higher tolerance. Pressure ratings for pre-1973 valves and fittings need to be verified with the manufacturer.

6. PRESSURE AND TEMPERATURE STABILIZATION

Time shall be allowed for the temperature of the pipeline facility and test medium to reach equilibrium which results in pressure stabilization.

The start of the hydrostatic pressure test shall only begin after the pressure and temperature of the test medium has stabilized.

The hydrostatic pressure test is acceptable when the pressure remains above the required test pressure with no pressure loss during the test.

7. TESTING REQUIREMENTS FOR CERTAIN APPLICATIONS

7.1 Tie-In Joints

Each tie-in joint is exempted from the test requirements. However, welded tie-in joints shall be visually inspected and, nondestructively tested in accordance with GS 1210.010 “Nondestructive Testing”. Additionally, non-welded tie-in joints shall be tested using leak detection solution at operating pressure if they are not included in the pressure test.

7.2 Tapping and Stopping Fittings

Tapping and stopping fittings shall be tested prior to tapping the pipeline. The preferred method is to test pneumatically per Section 9.2 in gas standard GS 1500.010 “Pressure Testing”. When pressurizing a tapping or stopping fitting, the maximum pressure differential between the internal pipeline pressure and the intended test pressure shall not be exceeded in accordance with Exhibit C, Table 5 in GS 1500.010 “Pressure Testing.”

7.3 Pre-Fabricated Units, Short Sections of Pipe and Station Piping

For pre-fabricated units, such as block valve settings, regulation and/or measurement settings, cleaner settings, etc., a post installation test may be impractical. These shall have a pre-installation pressure test conducted by maintaining a pressure at or above the test pressure for at least one (1) hour except that a duration of 15 minutes may be used for pre-fabricated units that will operated at less than 100 PSIG. When the pre-fabricated unit is to have a MAOP that produces a hoop stress that is 30% or more of SMYS, the test duration shall be at least four (4) hours.

In a Class 1 or Class 2 location, each compressor station, regulator station and measuring station shall be tested to at least Class 3 location test requirements. The test pressure shall be a minimum of 1.5 times the design pressure.

Temporary bypass lines shall be tested in accordance with this standard or if tested pneumatically per GS 1500.010 “Pressure Testing.”

7.4 Non-Pipe Component

If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required provided that the manufacturer of the component certifies the following.

a. the component was tested to at least the pressure required for the pipeline to which it is being added,

b. the component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added, or

c. the component carries a pressure rating of at least the MAOP of the line on which it is installed established through applicable, e.g., ASME/ANSI, MSS specifications, or by unit strength calculations as described in CFR 49 Part 192.143.

7.5 Pre-Testing

Where pre-tested pipe is used for the replacement of short sections of main or transmission line in lieu of on-site hydrostatic pressure testing, the pre-tested pipe shall be tested in accordance with this standard. Documentation of the pre-test shall be retained and referenced on the appropriate job orders and/or electronic database.

8. PREPARATION FOR HYDROSTATIC TESTING

8.1 Environmental

All environmental permits related to construction activities, water procurement, and water discharge shall be obtained prior to commencing test preparation activities.

8.2 System Operations Preparation – In-Service Pipelines

Prior to removing a pipeline from service to perform a hydrostatic pressure test, the project schedule and scope shall be coordinated with Gas Control personnel.

All temporary gas considerations shall be in place prior to taking a pipeline out of service for testing. The temporary gas considerations may include but are not limited to the following.

a. Modifying system flows/operations to address back feed requirements.

b. Portable compressed or liquid natural gas bottles/supplies for single source areas.

c. Construction of by-pass feeds.

8.3 Water Testing Requirements

Water analysis shall be obtained from each non-potable water source. The water source for each test section should be indicated on the project specific test plan. The water analysis shall be performed by a Company approved laboratory. The water analysis at minimum shall test for the following.

a. Acid-producing bacteria (APB).

b. Sulphate-reducing bacteria (SRB).

c. pH.

d. Salinity.

e. Suspended solids.

Company environmental personal shall be consulted to determine if any additional testing is required and for assistance in interpretation of results.

The water should not show the presence of APB or SRB. It is recommended that the pH be kept between 4 and 11. If the pH value of the water is outside of this range, the water shall be chemically treated. The water shall not contain silt, suspended material, or harmful corrosive components. Suspended solids can leave deposits. If the available water contains solid material, the solids should be separated out and/or filtered prior to filling the pipeline.

If a potable water source is used analysis is not required.

8.4 Pipeline Preparation

8.4.1 Connections and Taps

Review all high pressure taps, regulator stations, local production stations and all supply and delivery points feeding into and out of the line being cleaned. All taps should be blind flanged or capped and tagged out of service prior to cleaning and hydrostatic testing. Non-mainline ball valves shall be in the half open position and all other valves shall be in the full open position, and blind plated or capped.

8.4.2 Cleaning – New Construction

Brush and/or squeegee cleaning pigs using compressed air shall be run through the line prior to the water fill operation. On new pipelines, magnet pigs should be considered to pick up debris and mill scale. A temporary receiver shall be installed at the end of each test section to receive debris and the cleaning pigs unless the pig is being pulled through the pipeline. Cleaning pigs shall be repeated as required until the test section is cleaned to the satisfaction of the Company's Representative.

8.4.3 Cleaning – Existing Pipelines

Brush and/or squeegee pigs using compressed air shall be run through the line prior to the water fill operation. For pipelines that have been in operation, a large number of cleaning pig runs may be required for proper cleaning. Dust or fluid from the vented end shall be controlled. A vented double walled storage tank may be required if there is a potential for hazardous waste.

Launchers and receivers should be equipped with full port isolation valves so the pig runs can be performed with a line pack providing back pressure to help control the pig speed for much more effective performance and safety.

8.4.4 Environmental Considerations

The Company should involve environmental personnel in the cleaning process when it is suspected that the pipeline contains contaminants. The environmental personnel should test contaminants and liquids collected from the cleaning runs to determine their effect on the fill water and the environment if a release were to occur. All Company safety requirements for handling internal pipeline fluids and contaminates should be adhered to. The environmental personnel should consider if cleaning the pipe with detergents or chemicals is required and appropriate methods for handling and disposing of contaminated water.

8.4.5 Pigging – New Construction

For new pipelines, a caliper geometry pig should be run through the line to determine if there are any deformations or damage to the pipe that need to be repaired prior to testing.

Results of the pigging operation shall be analyzed and shared with the local Pipeline Integrity Management Team.

8.4.6 Pigging – In-Service Pipelines

For vintage pipelines, a geometry pig should be run to ensure that all piping components that may hinder the passage of fill and dewatering pigs have been removed prior to the test. Based on the type of pig being used, including cleaning pigs, consideration should be given to installing a transmitter inside to allow the pig to be located in case it becomes stuck in the line.

Results of the pigging operation shall be analyzed and shared with the local Pipeline Integrity Management Team.

8.4.7 Test Manifold Preparation

A test manifold shall be installed at each end of the test section. The test manifold is the inlet for the test medium and the location of the measurement devices. Couplings and mechanical joints are not to be used in the test manifold.

9. PERFORMING THE HYDROSTATIC PRESSURE TEST

The following are guidelines for performing the hydrostatic testing.

9.1 Pipe Filling

Prior to filling, verify that all valves are in the fully open position.

The pipeline should be filled slowly and consistently with a vent that can be throttled on one end in order to remove air pockets. A minimum of one bi-directional fill pig shall be run immediately ahead of the water column during the filling process to mitigate air entrapment. The rate of travel of the fill pig should be controlled with back pressure to ensure a constant speed and that the water column behind the pig is not broken during filling.

Use pumps with sufficient capacity to fill the line in a reasonable timeframe. A calibrated flow meter sized to measure the maximum fill rate of the test water shall be used during filling. The flow meter shall be of a type and capacity to accurately measure water volumes to within plus or minus 0.5% of actual volume. The water supply shall provide sufficient volume and rate to ensure uninterrupted filling of the test section. The amount of air introduced into the pipeline during filling operations shall be minimized.

If non-potable water is used, ensure that sediment and debris are not introduced into the pipeline by using suitable filters and screens.

As soon as it is believed that the pipeline is completely full of water, all vents shall be cracked open to ensure that a full steady stream of water is flowing out the vent while the fill pump is still operating. If any air bubbles are present, the vents should remain cracked open until water flow indicates the air has been evacuated from the vent.

9.2 Temperature Stabilization

After the pipe has been filled, the test shall not begin until the temperatures measured at each end of the test section stabilize. The time to stabilize varies depending on ground conditions and pipe size and may take up to 24 hours. During the temperature stabilization process, temperature recorders shall be used to record the temperature-time plot.

For location requirements of the temperature recorders see Section 12.2.

The test shall not progress until the temperature of the water has stabilized.

9.3 Pressurization of the Pipeline

Prior to starting the test, all ball valves should be placed in the one-half open position. All other valves shall be placed in the full, open position. Blind flanges or caps shall have been installed on all open connections.

A variable speed, positive displacement pump capable of maintaining a constant pressurization rate shall be used.

Once pressurization has commenced, the pressure shall be increased slowly until it reaches 75% of the minimum test pressure and held for a typical period of one (1) hour. The entire test section shall be checked for leaks during the hold period. If any leaks are found that cannot be rectified safely, the pressure shall be reduced and the leaks repaired before beginning the hydrostatic pressure test.

The pressure in the pipeline should next be increased to the required test pressure (adjusted for elevation). The test time is started once pressure stabilizes. The test start time shall be recorded.

The pipeline may be re-pressured to maintain the required test pressure. If at any point the pressure drops below test pressure, the test period shall be restarted. Any time during testing, the pressure can be bled off to ensure that the maximum pressure designated for the test is not exceeded.

During testing, the pressure and temperature data shall be recorded. When using a nonelectric deadweight, measurements shall be recorded at 10 minute intervals for the first hour and at 15 minute intervals for the remainder of the test. When using an electronic deadweight, the temperature shall be recorded every 10 minutes and the pressure shall be recorded at a minimum every 15 seconds and printed out every 15 minutes.

Any time the pipeline is re-pressurized or pressure is bled the volume of water added or removed and associated pressure change shall be recorded on the test data log, see page 2 of Exhibit B.

9.4 Patrolling During the Test

The pipeline shall be patrolled during the test period. This patrol shall check the test segment for any indications of a leak.

If a leak is found monitor the pressure drop to determine the leak rate and to attempt to find the leak using the best applicable detection methods for the specific scenario.

If the leak cannot be rectified safely, or cannot be located, the test shall be abandoned until the condition is rectified.

9.5 Freezing

When testing at low ambient temperatures, all piping and appurtenances shall be protected against freezing during testing. Insulation can be provided by the use of blankets or straw matting, or piping may be heated. Environmentally safe anti-freeze may be mixed with water to prevent freezing where economical. Typical freeze depressants include methanol, calcium chloride, ethanol, isopropanol, ethylene glycol, and propylene glycol. Methanol is easy to remove from the water after testing and does not pose a corrosion threat. Consult the environmental department prior to selecting a freeze depressant and have a handling plan for separation, disposal and discharge.

The temperature of the fill water shall be monitored to maintain a temperature of 37°F or higher. If necessary, the initial portion of the fill water should be heated to 95°F or greater prior to being pumped into the pipeline.

When low ambient temperatures are expected, precautions should be outlined on the project test plan.

9.6 Pressure vs. Volume Plot

Hydrostatic pressure testing a pipeline to greater than 90% of the SMYS of the pipe requires the use of a pressure-volume (PV) plot. This plot is used to identify pipe segments that are experiencing permanent deformation and to determine if a leak has developed during testing.

The PV plot records the increase in the pressure versus volume of water pumped into the pipeline test section. A constant rate of increase in pressure versus volume indicates that the yield strength of the pipe has not been surpassed. Permanent deformation of some pipe in the pipeline or a possible leak is indicated by a decrease in the rate that the pressure increases versus volume. When a point is reached where twice as much water is required to increase the pressure 10 psi as was previously needed (referred to as “double the strokes”), the yield strength of some pipe may have been surpassed or a leak may have occurred. If this condition occurs the test should be put on hold until the reason for the problem is investigated, see Section 11.

The pressure vs. volume plot should commence following the one (1) hour hold at 75% of the required test pressure and shall consist of a graph showing water volume added (pump strokes, gallons, etc.) versus pressure at 10 psi intervals or at intervals sufficient to show any deviation from a straight line. The scale selected for plotting the pressure-volume curve shall be chosen so that the plotted line lies between 45° and 75° from the horizontal. A constant pumping rate shall be maintained during pressurization, and sufficient water shall be provided to complete the plot without stopping until minimum test pressure is reached.

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9.7 Recording Gauge Connection

Steps shall be taken to prevent water from coming into contact with the recording gauge. This can be accomplished by providing an interface of oil between the recording gauge and the pipeline being tested.

The recording gauge and deadweight shall be positioned as specified on the project specific test plan and/or drawings. The location of the pressure gauge shall be correlated to the test elevation to ensure the test is completed at the correct pressure level. Exhibit C includes the pressure calculation for elevation variations.

Depending on the length of the test section, consider positioning additional pressure gauges at each end of the test section for informational purposes.

9.8 Test Acceptance

Pertinent test information shall be entered onto all test charts whether the test was successful or not. The person in charge of the test shall sign the pressure and temperature charts after successful completion of the test. All test charts, dead weight logs and information on leaks or failures shall be delivered to the Company's Representative at the completion of the test. The Company's Representative shall receive the test records from the person in charge and confirm that the test was successfully completed.

9.9 Dewatering

Once testing is completed, the valves shall be placed in the full open position and a squeegee, polyethylene, or other appropriate pig shall be run to dewater the pipeline. Air pressure shall be used to control the speed of the pig during dewatering. The pipeline shall be dewatered in accordance with the project specific test plan and discharge permits. The discharge shall be controlled to prevent erosion damage at the discharge point. The flow rate shall be monitored and controlled to meet permit requirements to filter and/or discharge to a sanitary sewer.

Ensure complete dewatering of the test segment by pigging continuously until no more water sweeps out of the test section.

After the test section has been dewatered, all valve body drain plugs shall be removed, carefully cleaned, taped (Teflon) and replaced.

After the dewatering operation is complete the pipe should be kept pressurized or with pipe ends covered if there will be a delay before drying begins.

9.10 Drying of Mains

The pipeline shall be dried to a dew point of –20 °F or less, as found using a calibrated hygrometer. The Company shall blow residual water from all taps, drips, and valve bodies.

The Corrosion Control group should be consulted for remediation in the event that internal moisture levels in the pipe cannot be reduced to the minimum.

The Company's Representative shall confirm that the main or transmission line has been dried in accordance with this procedure.

After the drying operation is complete the pipe should be kept pressurized or with pipe ends covered until ready to be placed in service.

9.11 Water Disposal

If allowed to dispose of water on site, pump water away from the right-of-way to a sewer or ditch. If water pools at the site of the pipeline, it can cause uplift. The test water shall be disposed of in accordance with all applicable environmental requirements and in a manner that will not cause erosion, siltation, or damage to the ecosystem of the area. At a minimum, a splash pad and straw bale filters shall be used to prevent erosion. If required by the permit, samples of the water used for testing shall be sent for analysis. Verify with the environmental group prior to discharge.

Alternate methods for test water disposal may include contracting with wastewater disposal companies or municipal water treatment facilities. Wastewater disposal companies and municipal water treatment facilities operate under permitting guidelines that often eliminate the need for the utility to obtain separate discharge permits. As part of their service agreement, wastewater disposal companies or municipal water treatment facilities may place additional requirements on the source of the testing water.

10. SPIKE TESTING – IN-SERVICE PIPELINES

A spike test is a hydrostatic test in which the pressure is initially increased to a high pressure stress level, typically at least 10 percent higher than the minimum pressure desired for the post-spike duration of the test, for a short hold period and then reduced to the desired test pressure, at least a 5% decrease from spike pressure. Benefits of a spike test include inducing failure in critical defects while reducing sub-critical ductile flaw growth during the hold period.

A spike test should be considered under the following circumstances.

a. When the pipeline contains stress corrosion cracking or another form of environmental cracking.

b. When the pipeline has a history of defects such as selective seam corrosion that are prone to subcritical flaw growth during pressure tests.

When performing a spike test, the highest possible test pressure that will not cause deformation, expansion, or bulging is desired (up to 110% SMYS maximum). A spike test shall proceed as follows.

1. Increase the pressure to the desired test pressure (adjusting for elevation) following the procedure listed in Section 9.3.
2. A pressure vs. volume plot, as outlined in Section 9.6, shall be prepared.
3. Pressure increase shall be halted if the pipe begins to yield.
4. For an eight (8) hour hydrostatic test the spike test pressure shall be held for a minimum of 30 minutes. For a one (1) hour hydrostatic test the spike test pressure shall be held for a minimum of five (5) minutes.
5. After the required minimum spike test pressure duration has elapsed, reduce the test pressure by 10 percent to the designated test pressure and hold at this pressure for the duration of the pressure test.

If a spike test has been performed on a pipeline, a flame ionization or other Company leak survey should be performed along the test segment once it is returned to service.

11. MATERIAL FAILURE DURING TESTING

Material failure will be evidenced by a loss of test pressure. In wet areas, a dye additive may be added to distinguish water from material failure from standard ground water.

If material failure occurs, the test shall be stopped. In the event of a failure, the person in charge shall make every effort to minimize the amount of water discharged at the failure site, and shall control and contain this water to minimize damage.

Failed pipe shall be repaired or replaced using the applicable Company procedure. If the failure occurs in the seam of the pipe, the entire joint shall be removed from the pipeline, including the girth weld on both sides. For other leaks, a minimum of three (3) pipe diameters on each side of the defect shall be removed. The piece removed shall be marked for orientation with respect to the position in the pipeline and with the alignment sheet station number of the defect location. The failure surface shall not be cut or damaged during removal, transit or unloading. If the failed portion is too long for transport or handling, it may be cut at right angles to the failure edge. All portions are to be turned over to the Company's Representative.

Material failures shall be reported according to GS 1652.010 "Investigation of Failures." A metallurgical analysis should be performed to identify the root cause of the failure. Determine if the cause of the failure could be widespread if it is an isolated incident. Perform proper corrective action to ensure the integrity and safety of the pipeline.

After completion of the repair/replacement, re-perform the hydrostatic test. Time that passes before the failure and during replacement does not count toward the minimum required testing duration. Test duration shall be continuous.

12. PRESSURE AND TEMPERATURE RECORDERS

12.1 Pressure Recorders

A calibrated electronic or hydraulic deadweight (preferred) or pressure recording gauge suitable for a hydrostatic pressure test shall be used to record pressure during the test. The range of the pressure recording gauge(s) and charts selected will be such that adequate interpretation of the pressure and test time is possible. Recording charts shall be approved by the Company's Representative.

Deadweights shall be capable of measuring required pressures in maximum increments of one (1) psi.

Specifically, recording gauges used for hydrostatic pressure testing shall have been calibrated in the past three (3) months by an independent test lab.

The calibration record of the pressure recorder shall be reviewed for compliance and copy included with test records.

12.2 Temperature Recorders

Temperatures shall be measured using suitable devices, such as, electronic temperature recorders, or thermometers that are capable of measuring temperatures from 0 °F to 150 °F to the nearest 1 °F. A record of the pipeline temperature during testing shall be created. See Section 9.3.

Temperature recorders shall be located approximately 1000 feet from each end and in the middle of the pipeline test section (when practical). These recorders shall be located so that they will not be affected by ambient temperatures or changes in injection fluid temperature because of close proximity to the injection pump. The temperature bulbs when possible should be secured directly to the exposed pipe with suitable heat transfer compound, insulated and then backfilled to ground level at least 12 hours prior to the start of the hydrostatic pressure test.

13. RECORDS

A record for each section of pipeline being hydrostatic pressure tested shall be completed by the testing Contractor or Company's Representative. Hydrostatic pressure test results shall be recorded as specified in the following sections.

Records for pressure tests that are performed pneumatically on tie-in joints, tapping or stopping fittings, pre-fabricated units other appurtenances not included in a hydrostatic pressure test shall be in accordance with Section 12 in GS 1500.010 "Pressure Testing."

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Exhibits A and B of this standard contain images of the forms to be completed for a hydrostatic pressure test.

13.1 Record Requirements a Hydrostatic Pressure Test

13.1.1 Required Pressure Test Information

A valid pressure test record shall include at a minimum the following information.

a. Company name.

b. Work order number.

c. Medium used.

d. Test pressure.

e. Test duration.

f. Temperature recording charts.

g. Significant elevation variations.

h. Leaks and failures noted and their disposition.

i. Effects of temperature changes on the pressure of the test medium.

j. Confirmation of a successful test.

k. Responsible employee.

l. Name of the company or contractor performing the test, if applicable.

m. Test pressure recorded in WMS/Maximo shall be the minimum test pressure calculated at the highest elevation, based on the minimum test pressure recorded at the test station.

n. Pressure recording charts, or other record of pressure readings.

13.1.2 Pressure Test Record Forms

The following test record forms are used to record a hydrostatic pressure test. The forms include fields for all the information required by Section 13.1.1. Examples of the forms are shown in Exhibits A and B.

a. Form GS 1500.020-1 “Hydrostatic Pressure Test Form.”

b. Form GS 1500.020-2 “Hydrostatic Pressure Test Data Log.”

13.1.3 Pressure Test Record Requirements

A complete test record for each hydrostatic pressure test performed shall include the following.

a. Form GS 1500.020-1 “Hydrostatic Pressure Test Form.”

b. Form GS 1500.020-2 “Hydrostatic Pressure Test Data Log.”

c. Recording charts and/or printouts from pressure recording instruments and electronic deadweights.

d. Recording charts from temperature gauges.

e. All pipe, fittings, valves, and other components included in the pressure test shall be identified in written records and/or drawings.

f. Calibration records for all pressure gauges and deadweights used during the test to establish MAOP.

All test forms, recording charts and printed digital gauge receipts shall be included in the Work Order packet/WMSDocs.

13.2 Additional Record Requirements for Multiple Pressure Tests

If multiple pressure tests are conducted for subsections of a project that are placed in service at different times, each pressure test document shall identify the section of the project that was pressure tested with the following information.

a. Physical location of test (e.g. street address/street intersection/other or end of main).

b. Test performed on __ ' Footage of __ "Diameter pipe, (e.g. list all subsection included in test by footage and diameter).

c. Date pressure test performed.

The pipe segments(s) tested corresponding to each separate record form shall be indicated on a sketch of the project.

13.3 Records Requirements for Tapping and Stopping Fittings and Tie-in Joints

All pressure test data for tapping and stopping fittings, and tie-in joints tested at operating pressure using leak detector solution, shall be recorded on the proper pressure test form. A description and location of each fitting or tie-in joint shall be included on the form. Refer to Section 9.2 “Tapping and Stopping Fittings” in GS 1500.010 “Pressure Testing.”

13.4 Record Requirements for Pre-fabricated Units, Short Sections of Pipe and Station Piping

All pressure test data for pre-fabricated units, short sections of pipe (including tie-in pieces) and station piping shall be recorded on the proper test form. A description and location of each item being tested shall be included on the form.

13.5 Record Requirements for Pre-tested Pipe and Temporary Bypass Piping

Documentation of the test shall be retained and referenced on the appropriate job orders and/or electronic database.

13.6 Records Retention

Test records shall be retained for the life plus ten (10) years of the pipeline to confirm establishment of maximum allowable operating pressure (MAOP).

**EXHIBIT A
(1 OF 2)**

Hydrostatic Pressure Test Form (Retain Permanently)

Company: ☐CGV ☐CKY ☐CMA ☐CMD ☐COH ☐CPA ☐NIPSCO **Test Acceptable: ☐Yes ☐No**

LOA/TCC: ____________________ Pressure System No. ____________________ WO/JO: ______________________

Line Section Number: ______________

Project Description: ____

From Station Number: ______________ To Station Number: ______________ Reference Drawing: ___________________

Gauge Location Station Number: ______________ State: ______________ County: ______________ Township: _________

Design Pressure: __________ MAOP: _________ Did this occur in an HCA? ☐ Yes ☐ No

Pipeline Description

Length (Feet)	Outside Diameter (Inches)	Wall Thickness (Inches)	Pipe Grade	SMYS	Seam Type	New (yes/no)	In-Service (yes/no)

Design Pressure: ____________ MAOP: ___________ Lowest SMYS within test segment: _______________________________

Minimum flange or valve ANSI rating in test section: ____

Maximum Test Pressure: ________________ As Determined by: ____ 100% SMYS ____ Line pressure + 50 psig
____ 1.5 x design ____ Flange/valve rating
____ 2 x design ____ ______ % SMYS

Spike Pressure: ___________

Maximum Post Spike Pressure: ___________

Minimum Test Pressure: ___________ As Determined by: ____ 1.25 design ____ Line pressure + 50 psig
____ 1.5 design ____ ______ % SMYS
____ Operating Pressure

Minimum Test Duration: ________________

Comments: ____
____
____
____

**EXHIBIT A
(2 OF 2)**

Hydrostatic Pressure Test Form (Retain Permanently)

WO/JO: ________________ Date: _____________

Pressure Correction	Station Number	High	Low
High elevation of pipe:			NA
Elevation of gauge:		-	
Low elevation of pipe		NA	-
Difference in elevation:		=	=
Pressure correction (difference in elevation x 0.433):		=	=

Allowable Gauge Pressure	High	Low
Minimum test pressure (from above)		NA
High pressure correction (from above)	+	Na
Minimum allowable gauge pressure	=	NA
Maximum test pressure (from above)	NA	
Low Pressure correction (from above)	NA	-
Maximum allowable gauge pressure	NA	+

Comments: ____

____

Contact Information for Contract Firm performing the test (if applicable):

Company Name: ______________________ Address: ______________________

Phone: ______________________

Witness Sign-off:

	Printed Name	**Signature**	**Date**
Company Representative			
Project Manager			
Contractor Representative			
Contractor Representative			

**EXHIBIT B
(1 OF 2)**

Hydrostatic Pressure Test Data Log (Retain Permanently)

(to be completed during the test period)

Company: ☐CGV ☐CKY ☐CMA ☐CMD ☐COH ☐CPA ☐NIPSCO

LOA/TCC: ____________________ Pressure System No. ____________________ WO/JO: _______________________

Line Section Number: ______________

Project Description: ____

From Station Number: _____________ To Station Number: ______________ Reference Drawing: ___________________

Start Date: __________ Start Time: ________ ☐AM ☐PM

Stop Date: __________ Stop Time: ________ ☐AM ☐PM

Actual Test Pressure: __________

Actual Minimum Gauge Pressure: ___________ Actual Maximum Gauge Pressure: ___________

High Pressure Correction: - ___________ Low Pressure Correction: + ___________

Actual Minimum Test Pressure: = ___________ Actual Maximum Pressure: = ___________

Describe any leaks or failures that occurred and explain their disposition: ____

____

Additional Comments: ____

____

Test Supervisor

Test Contractor (if applicable): ____

Print Name: ______________________ Signature: ______________________ Date: _____________________

Test Contractor

Print Name: ______________________ Signature: ______________________ Date: _____________________

Company Representative

Print Name: ______________________ Signature: ______________________ Date: _____________________

Project Manager

Print Name: ______________________ Signature: ______________________ Date: _____________________

Record deadweight, temperature, volume of water added and removed, stroke count and buried probe readings on following pages.

EXHIBIT B
(2 OF 2)

Hydrostatic Pressure Test Data Log (Retain Permanently)

(to be completed during the test period)

WO/JO: ___________________ Date: ______________

Deadweight Serial Number: ___________________ Date Last Calibrated: __________________

Temperature Recorder Serial Number: ___________ Date Last Calibrated: __________________

Time	Deadweight	Temperature (°F Ambient)	Temperature (°F Pipe)	Water Volume Added	Water Volume Removed	Stroke Count	Remarks

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**EXHIBIT C
(1 OF 2)**

Method to Determine Water Requirements

Prior to conducting a hydrostatic pressure test the amount of water required to fill each test section shall be calculated using the following equation.

$$Fill\,Volume\ (gallons) = 0.0408\ x\ Pipe\ Inside\ Diameter\ (inches)\ x\ pipe\ length\ (feet)$$

In order to calculate the total water required to achieve test pressure use the following equation:

$$Volume\ @\ Test\ P\ (in\ gallons) = Fill\ Vlume\ x\ Fwp * Fpp * \ Fpwt$$

Fwp = Factor to correct the compressibility of water due to pressure

Fpp = Factor to correct for volume change in pipeline due to increase in pressure

Fpwt = Factor to correct for change in water volume and pipe volume due to change in temperature from base of 60°F

$$Fwp = \frac{1}{1 - (4.5 * 10^{-5}) * \frac{Ptest}{14.73}}$$

$$Fpp = 1 + \left[\left(\frac{D}{t}\right) * (\frac{0.91 * Ptest}{30 * 10^6})\right] + 3.6 * 10^6 * (T - 60)$$

Fpwt can be approximated as 1.0 if temperature during testing (ground temperature) is between 40°F and 80°F. If ground temperature is outside of that range consult a hydrostatic testing subject matter expert to verify water volume required.

Ptest= Hydrostatic Test Pressure

D = Outside Diameter

t = Pipe nominal wall thickness, inches

T = Pipe Temperature (during test)

EXHIBIT C
(2 OF 2)

Example Calculation to Pressure Variation due to Change in Elevation

Conditions:
Pipe: 24” OD, 0.250” WT, API 5L, X60 (Note 60,200 SMYS in AP assumed to be 60,000 psi), HFW
Pipeline design MAOP: 625 psig (Assume class 3 location with 0.5 design factor)
Minimum Elevation: 800 feet
High Point Elevation: 1,200 feet
Minimum Test Pressure, P_{min}: 150% pipeline design MAOP
Maximum Allowable Test Pressure, P_{allow}: 100% SMYS

Calculations:
1) Minimum Test Pressure, P_{min}

$$\boldsymbol{Pmin} = 150\% \text{ x MAOP}$$
$$= 938 \text{ psig}$$

2) Maximum Allowable Test Pressure, P_{allow}

$$P_{allow} = 100\% \text{ SMYS} = \frac{\boldsymbol{S*2*t}}{\boldsymbol{D}} = \frac{\mathbf{60{,}000*2*0.250}}{\mathbf{24}} = 1{,}250 \text{ psig}$$

3) Test Gradient, T_G

T_G = (elevation change x 0.433 psig/ft)
Elevation change = High point elevation – Minimum elevation
= 400 ft
TG = (400 ft x 0.433 psig/ft)
= 173.2 psig

4) Maximum Test Pressure, P_{max}

$P_{max} = P_{min} + T_G$
= 1,111.2 psig

Result:
Since the maximum test pressure of 1,111.2 psig is lower than the maximum allowable test pressure of 1,250 psig, the test section design for the segment meets the test requirements.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	Pipelines – Shutdown and Startup	Standard Number: GS 1620.010
Supersedes: N/A		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605 (b)(5)

1. GENERAL

The Minimum Federal Safety Standards require the Company to have procedures for starting up or shutting down of any part of the pipeline so as to ensure operations within the Maximum Allowable Operating Pressure (MAOP), plus the build-up allowed for operation of overpressure protection devices.

The Company's procedures include, but are not limited to, the following.

a. Ensuring that the procedural manual for operations, maintenance and emergencies addresses the new pipeline.

b. Testing each pipeline to establish the MAOP.

c. Testing each pipeline to prove tightness and/or strength.

d. Commissioning new and reinstating existing pipelines.

e. Inspecting overpressure protection devices required for start-up.

f. Determining requirements for purging and notification of customers, public officials, and internal departments.

g. Establishing communications with field personnel and gas control personnel if applicable.

h. Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established.

i. Conducting follow-up leakage surveys, if applicable.

j. Updating maps and other pertinent operating records.

k. Tying-in new pipeline segments.

l. Preventing unauthorized turn-on.

m. Taking appropriate action when downstream leakage is indicated.

n. Shutting down a pipeline.

o. Abandoning a pipeline after shutdown.

p. Responding to unusual or abnormal operating and maintenance conditions.

2. SHUTDOWN AND STARTUP PROCEDURES

The following list comprises the Company's operating and maintenance procedures for pipeline shutdown and startup. In addition, the Company's construction gas standards also address shutdown and startup activities.

GS Series 1150 (XX)	Emergency Plan
GS 1500.010(XX)	Pressure Testing
GS 1660.010(XX)	Maximum Allowable Operating Pressure
GS 1680.010	Tie-Ins and Tapping Pressurized Pipelines
GS 1690.010	Purging New Construction and Abandonment
GS 1740.010(XX)	Abandonment of Facilities
GS 1750.010	Pressure Regulator Station Operation and Maintenance
GS 1756.010	Annual Review of Primary Relief Devices

(XX) denotes that state-specific versions exist for the applicable gas standards

NiSource
Distribution Operations

Gas Standard

Effective Date: 07/01/2013	**Class Location Determination for Transmission Lines**	Standard Number: **GS 1640.010**
Supersedes: 01/01/2010		Page 1 of 18

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.5

1. PLANS

A class location study shall be completed for all Company owned transmission lines, with the exception of a transmission line that has a maximum allowable operating pressure (MAOP), which results in a hoop stress of less than 40% of its specified minimum yield strength (SMYS) and is designed, constructed, and operated based on the requirements of a Class 4 location.

For new or replacement transmission lines, Engineering personnel responsible for designing the project (i.e., Transmission and M&R Design Team) are responsible for conducting the initial class location study, if required. For existing transmission lines where there is a change in MAOP or class location status, Field Engineering (or GM&T in Indiana) is responsible for completing the initial class location study, if required. The class location study shall be coordinated with the personnel managing the Company's Integrity Management Program.

Refer to GS 1660.020 "Maximum Allowable Operating Pressure (MAOP)," GS 2110.020 "Steel Pipe Design," and GS 1704.010 or GS 1704.010 (MA) "Patrolling Transmission Lines" for additional guidance on determining the necessity of completing a class location study.

2. CLASS LOCATION DEFINITIONS

"Class Location Unit" is an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline.

"Class 1 Location" is a class location unit that has 10 or less buildings intended for human occupancy.

"Class 2 Location" is a class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

"Class 3 Location" is:

a. any class location unit that has 46 or more buildings intended for human occupancy; or

b. an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

"Class 4 Location" is a class location unit where buildings with four or more stories above ground are prevalent. For the purpose of this definition, "prevalent" means that more than 50% of the buildings within a "sliding mile" (see Exhibit C) are 4 or more stories above ground.

NOTE: Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

3. CLASS LOCATION DETERMINATION

The initial class location study can be conducted by completing a field survey and plotting onto an operation map/GIS or other appropriate map the location of existing buildings intended for human occupancy, buildings occupied by 20 or more persons during normal use, buildings having four or more stories, and small well defined outside areas occupied by 20 or more persons during normal use along the proposed main. In addition to the aforementioned map(s), the class location study shall be documented by completing Form GS 1640.010-1, "Class Location Study," Exhibit A, or an equivalent form/method.

A recommended best practice is to complete at least one form for each class location as it changes along the pipeline. Multiple forms may be used for each class location for different pipe specifications.

3.1 Planning

Obtain consent from local Field Engineering leadership regarding the plans for completing the class location study (e.g., the extent of the study).

When it is determined that an initial class location study is needed, the following items should also be completed.

a. Consult with a Company GIS or Mapping Specialist to review available landbase maps (e.g., aerial photos, inventory maps, GIS landbase) that may be used during the field identification and verification of existing buildings and other areas of interest. Other areas of interest may include playgrounds, recreation areas, picnic areas, etc. (i.e., small well defined outside areas occupied by 20 or more persons during normal use).

b. Plot the proposed route of the new or replacement pipeline or the existing pipeline onto the landbase map(s).

c. Plot the 220 yard and 100 yard corridor lines from the centerline of the existing or proposed pipeline. For a proposed pipeline, a best practice is to widen the corridor for the study to accommodate possible field changes during construction.

d. Schedule the timing of the field verification work, which may coincide with other regularly scheduled O&M activities, such as leakage inspections or pipeline patrols. For a proposed pipeline, the field verification should be done after a majority of the easements and/or permits for the pipeline have been secured. If the initial class location study is completed based on a proposed pipeline location, it should be confirmed after construction is completed. The study should be finalized prior to construction of the pipeline, but no later than four months after the pipeline in-service date.

e. Determine labor and equipment resources needed for the field verification work. Consideration should be given to the availability of qualified field personnel, training and instructions, and acquisition of equipment needed to perform the survey.

NOTE: A best practice is to complete a comprehensive class location study identifying all buildings intended for human occupancy and all outside areas of interest for future reference. However, an abbreviated class location study may be considered. For example, if the pipeline is designed and constructed for a Class 3 location, the class location study may only include the identification of buildings with four or more stories.

3.2 Field Verification

Field verification is the process by which the accuracy of the pipeline as plotted on the landbase map(s) is verified, and existing buildings and other areas of interest are identified on the map(s). Other areas of interest may include playgrounds, recreation areas, picnic areas, etc. (i.e., small well defined outside areas occupied by 20 or more persons during normal use). Field verification activities may include the following tasks.

a. Locate pipeline and easements (or proposed pipeline and easements) on the landbase map(s) with the correct centerline. Stationing (i.e., 1+00) should be referenced along the pipeline.

b. Label structures or outside areas of interest. Use Form GS 1640.010-2 “Class Location Field Verification Survey” (see Exhibit B), or equivalent, to document each non-residential structure or outside area with the address or location, building/area use or function, and occupancy estimate, as appropriate.

c. Take measurements between the pipeline (or proposed pipeline) and structure/outside area of interest (closest corner/edge of structure/outside area). Measurements are not required to be taken if the structure or outside area of interest is accurately identified on the landbase map.

d. Take pictures (digital preferred) along the corridor to capture significant details relevant to the study.

e. Obtain GPS coordinates for the pipeline and structures/outside areas of interest.

f. Note discrepancies on the landbase map(s), such as construction of new buildings.

g. Note special conditions within the pipeline easements and corridor, such as 3rd party excavations, the need for right-of-way clearing, possible future developments, wetland areas, and potential encroachments.

3.3 Determination of Class Location

After field verification, review the map(s) and use the following sequence of steps, as necessary, to determine the class location.

a. Locate and designate Class 4 location units. Using the “sliding mile” principle, Exhibit C, locate “sliding miles” where buildings of four or more stories above ground are prevalent. A Class 4 location unit ends 220 yards from the nearest building having four or more stories above ground.

b. Locate and designate Class 3 location units. Using the "sliding mile" principle, Exhibit C, on the remaining sections of main, identify and establish Class 3 location units.

c. Identify buildings or small, well-defined areas occupied by 20 or more persons during normal use which are not in a Class 3 or 4 designated location unit and establish Class 3 location areas as illustrated in Exhibit D.

d. Proceed with a forward and backward house count on the remaining sections of the main, using the "sliding mile" principle and assigning appropriate Class 1 and/or 2 location units.

NOTE: The length of a Class 2 or Class 3 location may be adjusted when there is a cluster of buildings intended for human occupancy, so that the class location ends 220 yards from the nearest building in the cluster.

4. NOTIFICATION OF CLASS LOCATION DETERMINATION TO INTERESTED PARTIES

Inform the following Company personnel about construction and/or operating requirements (i.e., leakage and patrolling schedules) based on class location determination.

a. Project Management team and local Construction leaders/supervisors,

b. local Field Engineering Leader,

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c. local Field Operations Leaders/Supervisors,

d. Integration Center, or equivalent scheduling personnel,

e. local leakage inspectors,

f. local personnel responsible for performing patrols, and

g. personnel responsible for managing the Company's Integrity Management Program.

Provide copies of class location study maps, as necessary (e.g., leakage and patrolling personnel, Integrity Management personnel).

5. ANNUAL VERIFICATION

An annual verification of the class location shall be completed for all transmission lines, with the exception of a transmission line that has an MAOP which results in a hoop stress of less than 40% of its SMYS and is designed, constructed, and operated based on the requirements of a Class 4 location. Refer to GS 1640.020 "Annual Class Location Verification" for additional guidance.

6. RECORDS

Class location study maps and records shall be kept on file by local Field Engineering or GM&T, as appropriate. In addition, copies shall be kept in the Company's Integrity Management file.

EXHIBIT A
(1 of 8)

Instructions for Completion of Form GS 1640.010-1
"Class Location Study."

The following items are keyed to Form GS 1640.010-1 “Class Location Study”, page 8 of this exhibit. Each blank must be completed as it relates to the pipeline covered by the Class Location Study. If the information to enter on the form is "none" or "not applicable," then insert "N/A" in the appropriate blank. If the information is unknown, enter “unknown” in the appropriate blank.

Key	Item	Description
1	Company	Choose from drop-down list.
	Pipeline Location Information	
2	Piping System Name	Indicate Piping System Name (refer to GS 1660.010 “Piping System Names and Identifiers”).
3	Piping System/Segment ID	Indicate Piping System Identifier (refer to GS 1660.010 “Piping System Names and Identifiers) and Piping Segment Identifier, if applicable (refer to GS 1660.020 “Maximum Allowable Operating Pressure”).
4	Section ID	Assign an identification number or letter or combination thereof, which corresponds to the particular section of pipeline covered by this form.
5	Map Reference(s)	List the various operations map(s), GIS grid(s), transmission map(s), etc.
6	Length of Section	Length of section in feet.
7	Station and/or Location Information	If available, indicate the pipeline stationing (from station, to station) for the pipeline. If stationing is not available, provide a location description (e.g., starting 510’ west of the centerline of County Line Road, ending 1200’ east of Dutch Ridge Road, Trenton Township, Clark County).

EXHIBIT A
(2 of 8)

Key	Item	Description
8	Class Location	Choose appropriate Class Location from drop-down list based on maps showing population density, as defined and directed by GS 1640.010 “Class Location Determination for Transmission Lines.”
9	MAOP	Indicate the existing Maximum Allowable Operating Pressure (MAOP) of the pipeline.
10	Hoop Stress (%SMYS) produced by the MAOP	Display the hoop stress (%SMYS) produced by the MAOP by using the information indicated in Keys 13 – 19. Refer to GS 2110.020 “Steel Pipe Design.”
11	MOP	Indicate Maximum Operating Pressure (MOP) for the pipeline. Refer to GS 1660.020 “Maximum Allowable Operating Pressure (MAOP)” for additional guidance regarding MOP.
Pipeline Design Data NOTE: If more than one specification exists for Keys 12 – 26, each specification may be indicated on a separate line, or use multiple forms. Corresponding specifications should be linked (e.g., by providing a bullet reference number or letter). Refer to GS 2110.020 “Steel Pipe Design” if a value is unknown.		
12	Nominal Pipe Diam.	Indicate the nominal diameter(s) for the pipe.
13	Pipe Outside Diam.	Indicate the outside diameter(s) for the pipe. Refer to GS 2110.020 “Steel Pipe Design” Exhibit A “Properties of Pipe” table.
14	Pipe Grade	Indicate the grade specification(s) of steel pipe (e.g., GR-B, X-42, X-60) used for the pipeline.
15	Pipe Wall Thickness	Indicate the wall thickness(es) of the steel pipe.
16	Pipe Specification	Indicate the pipe specification(s) used for the pipeline. The current pipe specification is API 5L. Refer to GS 2110.020 “Steel Pipe Design” Table 1 for common historical pipe specifications.

EXHIBIT A
(3 of 8)

Key	Item	Description
17	Longitudinal Joint Type of Pipe	Choose the appropriate longitudinal joint type from the drop-down list. Refer to GS 2110.020 “Steel Pipe Design” Table 3 (pipe class column). The pipe class is based on the method used to manufacture the steel pipe (e.g., seamless, ERW).
18	Longitudinal Joint Factor of Pipe	Indicate the Longitudinal Joint Factor “E,” as defined by GS 2110.020 “Steel Pipe Design” Table 3.
19	Temperature Derating Factor of Pipe	Indicate the Temperature Derating Factor “T,” as defined by GS 2110.020 “Steel Pipe Design” Section 2.6.
20	Nominal Fitting Diameter	Indicate the nominal diameter(s) for the fittings used for the pipeline (e.g., elbows, reducers, tees).
21	Fitting Outside Diameter	Indicate the outside diameter(s) for the fittings used for the pipeline. Refer to GS 2110.020 “Steel Pipe Design” Exhibit A “Properties of Pipe” table.
22	Fitting Grade	Indicate the grade specification(s) of the fittings used for the pipeline (e.g., Y42, Y60).
23	Fitting Wall Thickness	Indicate the wall thickness(es) of the fittings used for the pipeline.
24	Longitudinal Joint Type of Fitting	Choose the appropriate longitudinal joint type from the drop-down list.
25	Longitudinal Joint Factor of Fitting	Indicate the Longitudinal Joint Factor “E,” as defined by GS 2110.020 “Steel Pipe Design” Table 3.
26	Temperature Derating Factor of Fitting	Indicate the Temperature Derating Factor “T,” as defined by GS 2110.020 “Steel Pipe Design” Section 2.6.

EXHIBIT A
(4 of 8)

Key	Item	Description
27	100% SMYS	Calculate and display the value representing 100% SMYS by using the pipe design formula in GS 2110.020 "Steel Pipe Design." The Design Factor "F" is 1.00. Use the factors of the pipe or fitting specifications, whichever produces the lowest value of 100%SMYS.
28	Class 1 72% SMYS	Multiply 100% SMYS (value in Key 27) by 0.72.
29	Class 2 60% SMYS	Multiply 100% SMYS (value in Key 27) by 0.60.
30	Class 3 50% SMYS	Multiply 100% SMYS (value in Key 27) by 0.50.
31	Class 4 40% SMYS	Multiply 100% SMYS (value in Key 27) by 0.40
32	Minimum Design Pressure of Components Other Than Line Pipe or Fittings	Includes components such as stopple fittings that are made from pipe, which are affected by class location. Rated cast components, such as valves or regulators, are not affected by class location.
33	Code Followed	Indicate the version of the code used to design, construct, and pressure test the pipeline. Versions of the code are listed below along with their effective dates: Prior to 1935: N/A 1935: American Tentative Standard Code for Pressure Piping 1942: American Standard Code for Pressure Piping 1944: Addition/supplement to 1942 edition 1947: Addition/supplement to 1942 edition 1951: Addition/supplement to 1942 edition 1952: ASA B31.1.8 – American Standard Association (ASA); American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems 1955: ASA B31.1.8 – Gas Transmission and Distribution Piping Systems 1958: ASA B31.8 – 1958 1963: Revision to 1958 edition 1966: Revision to 1963 edition 1967: USAS B31.8; United States of America Standards (USAS); Revision to 1966 edition 1968: ASME B31.8; American Society of Mechanical Engineers (ASME); Revision to 1967 edition 1970: 49 CFR Part 192; Code of Federal Regulations, Title 49 Transportation, Part 192 Pipeline Safety Regulations

EXHIBIT A
(5 of 8)

Key	Item	Description
34	Other Considerations	Indicate other considerations relevant to the pipeline design (e.g., designed for Class 4 because of known plans for 4-story office buildings in the vicinity of the proposed pipeline)
	Construction Data NOTE: Construction Data is for informational purposes. If a value is unknown, then enter "unkn" in the blank field.	
35	Year Constructed	Indicate the year that the pipeline construction was completed.
36	Minimum Cover	Indicate the actual minimum cover of the pipeline as it was constructed.
37	Nondestructive Testing of Welds	Indicate if the welds were nondestructively tested (e.g., x-ray). Indicate the percentage of welds that had a nondestructive test performed.
38	Protective Coating	Indicate if a protective pipe coating and/or wrap exists on the pipeline.
39	Coating Type	Indicate type of coating (e.g., X-Tech II extruded polyethylene, Fusion Bonded Epoxy, Powercrete) predominantly used on the pipe.
40	Joint Method	Choose the applicable method(s) used to join the steel pipe.
41	Weld Method	Choose the applicable method used to weld the steel pipe: Shielded Metal Arc Welding (SMAW) – Manual; aka stick welding Gas Metal Arc Welding (GMAW) – Semi-automated; aka MIG Oxyacetylene Welding (OAW) – Manual Submerged Arc Welding (SAW) – Automated Other – Indicate the "other" method used N/A – Indicate "N/A" if the method is coupled or coupled w/ restraint

EXHIBIT A
(6 of 8)

Key	Item	Description
42	Cathodic Protection	Indicate if a cathodic protection system was installed to cathodically protect the pipeline.
43	Cathodic Protection Type	Indicate the type of cathodic protection system that was installed (e.g., anode, impressed current system)
44	In-Service Date	Indicate the date that the pipeline was activated with gas.
45	Method of Direction Changes	Indicate the method(s) used to change direction.
46	Typical Easement Width	Indicate the typical easement width for the pipeline. Indicate N/A if the pipeline was installed within public road right-of-way.
47	Pipeline Location Information	Indicate typical pipeline alignment with respect to the pipeline easement or public road right-of-way (e.g., pipeline installed within 5 ft. of the easement centerline, pipeline installed in public road right-of-way at 2 ft. inside of road right-of-way). This information may help to investigate encroachment issues.
48	Other Considerations	Indicate other considerations relevant to the pipeline construction (e.g., pipeline directionally drilled at a depth of over 40 ft. beneath the river, pipeline installed following an electric transmission line).
	Testing Data	
49	Date of Last Test	Self-explanatory.
50	Duration of Test	Self-explanatory.
51	Test Medium	Choose the applicable test medium from the drop-down list.
52	Test Failures on Last Test	Self-explanatory.

EXHIBIT A
(7 of 8)

Key	Item	Description
53	Test Pressures	Indicate the minimum and maximum recorded test pressures after the test pressure stabilizes. Calculate and display the corresponding % SMYS by using the pipe design formula in GS 2110.020 “Steel Pipe Design.”
54	Testing Information	Indicate any pertinent additional information regarding the pressure test(s).
	Review and Approval	
55	Prepared By:	Print or type name and title of person who prepared Form GS 1640.010-1. The form must be completed by an Engineer or Engineering Technician. The preparer must also sign on the “signature” line. Indicate the date that Form GS 1640.010-1 was prepared.
56	Reviewed By:	Print or type name and title of person who reviewed Form GS 1640.010-1. The form must be reviewed by an Engineer. The Engineer that prepared the form may be the same Engineer that reviewed the form. The reviewer must also sign on the “signature” line. Indicate the date that Form GS 1640.010-1 was reviewed.

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Gas Standard

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EXHIBIT A
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CLASS LOCATION STUDY

Company <CHOOSE FROM LIST> **(1)**

Pipeline Location Information

Piping System Name **(2)**	Piping System/Segment ID **(3)**	Section ID **(4)**	Map Reference(s) **(5)**
Length of Segment **(6)**	Station and/or Location Information From: To: **(7)** Location:		
Class Location **(8)** <CHOOSE FROM LIST>	MAOP **(9)**	Hoop Stress (%SMYS) produced by the MAOP **(10)**	MOP **(11)**

Pipeline Design Data

Nominal Pipe Diam. **(12)**	Pipe Outside Diam. **(13)**	Pipe Grade **(14)**	Pipe Wall Thickness **(15)**	Pipe Specification **(16)**
Longitudinal Joint Type of Pipe <CHOOSE FROM LIST> **(17)**	Longitudinal Joint Factor of Pipe **(18)**	Temperature Derating Factor of Pipe **(19)**		
Nominal Fitting Diameter **(20)**	Fitting Outside Diameter **(21)**	Fitting Grade **(22)**	Fitting Wall Thickness **(23)**	
Longitudinal Joint Type of Fitting <CHOOSE FROM LIST> **(24)**	Longitudinal Joint Factor of Fitting **(25)**	Temperature Derating Factor of Fitting **(26)**		
100% SMYS **(27)**	Class 1 72% SMYS **(28)**	Class 2 60% SMYS **(29)**	Class 3 50% SMYS **(30)**	Class 4 40% SMYS **(31)**
Minimum Design Pressure of Components Other Than Line Pipe or Fittings **(32)**	Code Followed **(33)**			
Other Considerations **(34)**				

Construction Data

Year Constructed **(35)**	Minimum Cover **(36)**	Joint Method ☐ Solid Weld ☐ Coupled ☐ Coupled with Restraint **(40)**	Weld Method ☐ Shielded Metal Arc (Manual) ☐ Gas Metal Arc (Semi-automated) ☐ Oxyacetylene (Manual) ☐ Submerged Arc (Automated) ☐ Other ☐ N/A **(41)**
Nondestructive Testing of Welds **(37)** ☐ No ☐ Yes % of Welds Tested			
Protective Coating ☐ No ☐ Yes **(38)**	Coating Type **(39)**		
Cathodic Protection ☐ No ☐ Yes **(42)**	Cathodic Protection Type **(43)**	In-Service Date **(44)**	
Method of Direction Changes (miter joints, wrinkle bends, elbows, couplings, smooth cold bends, etc., if known) **(45)**			
Typical Easement Width **(46)**	Pipeline Location Information **(47)**		
Other Considerations **(48)**			

Testing Data

Date of Last Test **(49)**	Duration of Test **(50)**	Test Pressures **(53)** Minimum: psig %SMYS Maximum: psig %SMYS
Test Medium **(51)** <CHOOSE FROM LIST>	Test Failures on Last Test ☐ No ☐ Yes **(52)**	
Testing Information (failure info, previous tests, etc.) **(54)**		

Review and Approval

Prepared By: **(55)**			
Name	Title	Signature	Date
Reviewed By: **(56)**			
Name	Title	Signature	Date

EXHIBIT B
(1 of 3)

Instructions for Completion of Form GS 1640.010-2
"Class Location Field Verification Survey."

The following items are keyed to Form GS 1640.010-2 “Class Location Field Verification Survey”, page 3 of this exhibit. Form GS 1640.010-2 should correspond to related Form GS 1640.010-1 “Class Location Study.” Each blank must be completed as it relates to the pipeline covered by the Class Location Study. If the information to enter on the form is "none" or "not applicable," then insert "N/A" in the appropriate blank. If the information is unknown, enter “unknown” in the appropriate blank.

Key	Item	Description
1	Company	Choose from drop-down list.
	Pipeline Location Information	
2	Piping System Name	Indicate Piping System Name (refer to GS 1660.010 “Piping System Names and Identifiers”).
3	Piping System/Segment ID	Indicate Piping System Identifier (refer to GS 1660.010 “Piping System Names and Identifiers) and Piping Segment Identifier, if applicable (refer to GS 1660.020 “Maximum Allowable Operating Pressure”).
4	Section ID	Assign an identification number or letter or combination thereof, which corresponds to the particular section of pipeline covered by this form.
5	Map Reference(s)	List the various operations map(s), GIS grid(s), transmission map(s), etc.
6	Length of Section	Length of section in feet.
7	Station and/or Location Information	If available, indicate the pipeline stationing (from station, to station) for the pipeline. If stationing is not available, provide a location description (e.g., starting 510’ west of the centerline of County Line Road, ending 1200’ east of Dutch Ridge Road, Trenton Township, Clark County).

EXHIBIT B
(2 of 3)

Key	Item	Description
8	Structure or Outside Area Label	Label should correspond to the same structure or outside area identified on the Class Location Study map. Use letters, numbers, combination of letters & numbers, etc.
9	Station (if available) and Offset	Indicate the pipeline station (if available) and offset from the centerline of the pipeline perpendicular to the closest point or edge of the structure or outside area. If pipeline stationing is not available, indicate the distance (or offset) from the centerline of the pipeline perpendicular to the closest point or edge of the structure or outside area.
10	GPS Coordinate	If GPS equipment is available, indicate the GPS coordinate of the closest point or edge of the structure or outside area to the pipeline. If GPS coordinates are not taken, indicate "N/A."
11	Site Address or Location	Indicate the street address of the structure. If a street address is not available, identify the structure or outside area with appropriate location information (e.g., structure located 150 ft. south of the intersection of Main and High and 500 ft. from the centerline of High).
12	Site Use & Occupancy Estimate	Indicate the site use (e.g, playground, church, school) and occupancy estimate. The occupancy estimate should include a number per period of time (e.g. 10 persons per day, 50 persons per week).

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Distribution Operations

Gas Standard

Effective Date: 07/01/2013	**Class Location Determination for Transmission Lines**	Standard Number: **GS 1640.010**
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EXHIBIT B
(3 of 3)

CLASS LOCATION FIELD VERIFICATION SURVEY
NON-RESIDENTIAL STRUCTURE AND OUTSIDE AREA IDENTIFICATION

Company <CHOOSE FROM LIST> **(1)**			
Pipeline Location Information			
Piping System Name **(2)**	Piping System/Segment ID **(3)**	Section ID **(4)**	Map Reference(s) **(5)**
Length of Section **(6)**	Station and/or Location Information From: To: Location: **(7)**		

Structure or Outside Area Label: **(8)**	Station (if available) and Offset: **(9)**	GPS Coordinate: **(10)**
Site Address or Location: **(11)**		
Site Use & Occupancy Estimate: **(12)**		

Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

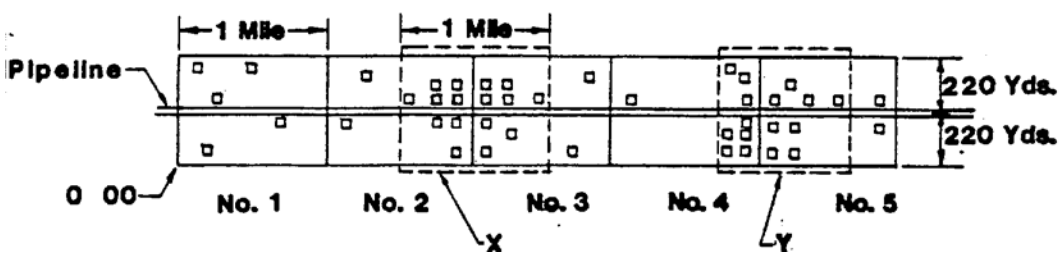
Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

Structure or Outside Area Label:	Station (if available) and Offset:	GPS Coordinate:
Site Address or Location:		
Site Use & Occupancy Estimate:		

EXHIBIT C

"Sliding Mile" House Count



Starting from 0+00, or the boundary for a cluster or a building or well-defined area occupied by 20 or more persons during normal use, and using the one-mile house count without variation in the location of the one-mile zone, the house count for:

No. 1 Section = 5

No. 2 Section = 10

No. 3 Section = 10

No. 4 Section = 9

Examined in this manner, all of these sections would be Location Class 1 because they all contain less than 10 buildings intended for human occupancy. However, using the "sliding mile" to include the housing densities as shown in phantom in Section X and Y, the classification is changed. Thus, the one-mile house count for:

X Section = 16

Y Section = 16

Therefore, the X and Y Sections would be Location Class 2.

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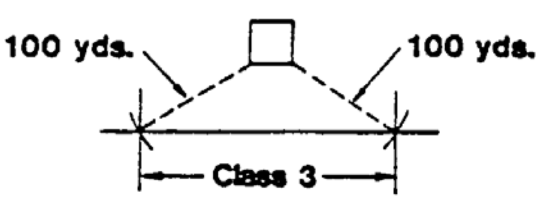
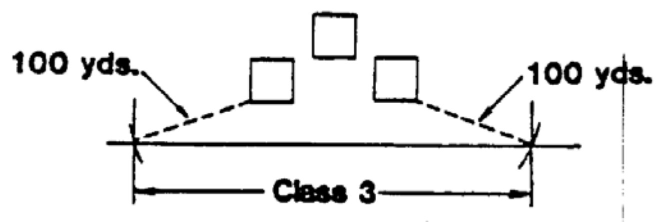
EXHIBIT D

Examples of Buildings And Small Well-Defined Areas Occupied by 20 or More Persons During Normal Use

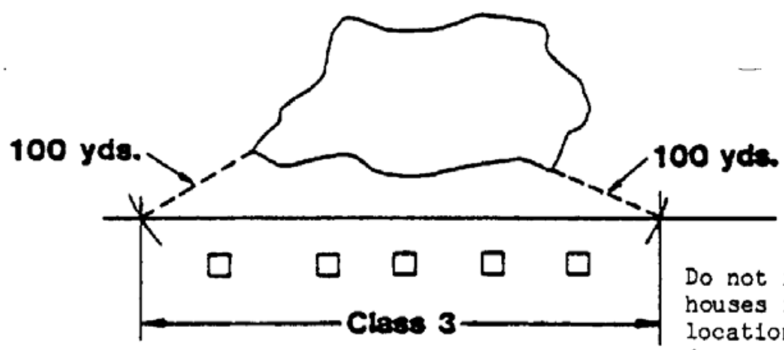
Single Building



Multiple Buildings



Example of Small-Well Defined Area



Do not include the 5 houses in this Class location in house count for adjacent sections.

Locate Buildings and Small Well-Defined Areas Occupied by 20 or More Persons During Normal Use

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Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.609, 192.611

1. GENERAL

An annual verification of the class location shall be completed for all transmission lines, with the exception of a transmission line that has a maximum allowable operating pressure (MAOP), which results in a hoop stress of less than 40% of its specified minimum yield strength (SMYS) and is designed, constructed, and operated based on the requirements of a Class 4 location. Refer to GS 1640.010 “Class Location Determination for Transmission Lines” for additional information.

The Company continually monitors the conditions along the pipeline. When the Company becomes aware of population or usage changes that may potentially create or change a class location, the Company will perform an evaluation of the area to determine if there is a change in class location. The Company expects the annual class location verification to be the primary process for identifying changes in class location. Nevertheless, field personnel performing routine O&M or pipeline integrity activities or Engineering department employees reviewing new development plans, may obtain information of land use changes which could affect the class location. Personnel in these positions should possess general transmission line awareness and, when encountering such information, should communicate such changes to Field Engineering. Field Engineering is responsible for ensuring an evaluation of the area is made to determine if there is a change to the class location.

2. ANNUAL CLASS LOCATION VERIFICATION

Field Engineering (or GM&T in Indiana) shall conduct the annual class location verification study.

NOTE: A best practice is to complete a comprehensive annual review of the class location, identifying all buildings intended for human occupancy and all outside areas of interest for future reference. However, an abbreviated annual review of the class location may be considered for Class 3 locations. For example, the Class 3 location review may only include the identification of buildings with four or more stories.

2.1 Planning

a. Gather existing class location study information.

b. Gather new information from available resources, such as the county courthouse, recent aerial photos, etc. Consult with a Company GIS or Mapping Specialist for potential new resources.

c. Compare existing and new information and identify potential new structures and other areas of interest on existing class location map(s). Other areas of interest may include playgrounds, recreation areas, picnic areas, etc. (i.e., small well defined outside areas occupied by 20 or more persons during normal use).

d. Schedule the timing of the field verification work, which may coincide with other regularly scheduled O&M activities, such as leakage inspections or pipeline patrols.

e. Determine labor and equipment resources needed for the field verification work. Consideration should be given to the availability of qualified field personnel, training, and instructions, and acquisition of equipment needed to perform the survey.

2.2 Field Verification

a. Verify and label new structures or outside areas of interest. Use Form GS 1640.010-2 “Class Location Field Verification Survey” (see GS 1640.010 “Class Location Determination for Transmission Lines”) to document each non residential structure or outside area with the address or location, building/area use or function, and occupancy estimate, as appropriate.

b. Take measurements between the pipeline and new structure/outside area of interest. Measurements are not required to be taken if the structure or outside area of interest is accurately identified on the landbase map.

c. Take pictures (digital preferred) along the corridor to capture significant details relevant to the study.

d. Obtain GPS coordinates for the pipeline and new structures/outside areas of interest.

e. Note special conditions within the pipeline easements and corridor, such as 3rd party excavations, the need for right-of-way clearing, possible future developments, and potential encroachments.

2.3 Class Location Verification

Form GS 1640.020-1 “Annual Class Location Verification” (see Exhibit A) or equivalent form or method, shall be used to document the annual class location verification. If the population density has changed, determine if the class location has changed. The following information shall be documented if the established maximum allowable operating pressure (MAOP) is not commensurate with the present class location:

a. the present **class location** for the pipeline segment;

b. the design, construction, and testing procedures followed in the original construction compared to those procedures required for the present class location (contact Gas Standards for guidance, if necessary);

c. the physical condition of the pipeline segment to the extent it can be ascertained from available records (e.g., leakage, damages);

d. the pipeline segment operating and maintenance history;

e. the hoop stress produced by the MAOP and the maximum actual operating pressure, and

f. the actual area affected by the population density increase and physical barriers or other factors which may limit further expansion of the more densely populated area, if applicable.

2.4 Class Location Study Documentation

The updated study may be documented by using Form GS 1640.010-1 "Class Location Study" or equivalent form/method (refer to GS 1640.010 "Class Location Determination for Transmission Lines").

3. CONFIRMATION OR REVISION OF MAOP

If the hoop stress corresponding to the established MAOP of a segment of pipeline is commensurate with the present class location, no further action is required.

If the hoop stress corresponding to the established MAOP of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the MAOP of that segment of pipeline must be confirmed or revised.

This confirmation or revision must be completed within 24 months of the change in class location. The 24-month time period begins when a building or buildings are ready for occupancy and not when the Company discovers that there are new buildings or completes its class location review. The revised MAOP may not exceed the MAOP that was established before the confirmation or revision. The MAOP shall be confirmed or revised according to one of the methods described in sections 3.1 to 3.3 of this procedure.

3.1 Previous Testing

If the segment involved has been previously tested in place for a period of not less than 8 hours, the MAOP is:

a. in Class 2 locations, 0.800 times the test pressure,

b. in Class 3 locations, 0.667 times the test pressure, and

c. in Class 4 locations, 0.555 times the test pressure.

The corresponding hoop stress of the pipe may not exceed:

d. in Class 2 locations, 72% of pipe SMYS,

e. in Class 3 locations, 60% of pipe SMYS, and

f. in Class 4 locations, 50% of pipe SMYS.

If documentation is not available indicating a pressure test duration of 8 hours or more, then the MAOP must be reduced as described in Section 3.2 or the MAOP must be confirmed by pressure testing as described in Section 3.3.

A corrective pressure reduction within the 24-month period, to ensure that the MAOP is commensurate with the existing class location, does not preclude establishing an MAOP under Section 3.3 at a later date.

3.2 MAOP Reduction

The MAOP of the segment involved must be reduced so that the corresponding hoop stress does not exceed:

a. in Class 2 locations, 60% of pipe SMYS,

b. in Class 3 locations, 50% of pipe SMYS, and

c. in Class 4 locations, 40% of pipe SMYS.

A corrective pressure reduction within the 24-month period, to ensure that the MAOP is commensurate with the existing class location, does not preclude establishing an MAOP under Section 3.3 at a later date.

3.3 Pressure Testing

Test the pipeline segment in accordance with GS 1500.010 “Pressure Testing” and establish the MAOP according to the following criteria:

a. The MAOP after the requalification test is:
   i. in Class 2 locations, 0.800 times the test pressure,
   ii. in Class 3 locations, 0.667 times the test pressure, and
   iii. in Class 4 locations, 0.555 times the test pressure.
b. The hoop stress based on the new MAOP may not exceed:
   i. in Class 2 locations, 72% of pipe SMYS,
   ii. in Class 3 locations, 60% of pipe SMYS, and
   iii. in Class 4 locations, 50% of pipe SMYS.

4. UPDATING PATROLLING AND LEAKAGE SURVEY SCHEDULES

When a class location has changed, Field Engineering (or GM&T in Indiana) shall notify the appropriate Field Operations and Integration Center personnel, or equivalent, so that the patrolling and leakage survey schedules can be updated, as necessary. Refer to GS 1704.010 “Patrolling Transmission Lines” and GS 1708.010 “Leakage Surveys” for frequency with respect to class location.

5. UPRATING

After confirmation or revision of a pipeline segment’s MAOP in accordance with Section 3 of this procedure, the Company may uprate the pipeline in accordance with its applicable uprating gas standards up to the limit identified in Section 3 by class location.

For Columbia Companies, refer to Gas Standards Series 5500 “Uprating” for the applicable uprating gas standards.

For NIPSCO, refer to Gas Design Standards 480-0010 “Pressure Elevation – Mains” and 480-0020 “Pressure Elevation – Services” for applicable uprating gas standards.

6. RECORDS

Form GS 1640.020-1 “Annual Class Location Verification” or equivalent form/method shall be filed in local Field Engineering (or GM&T in Indiana). However, when an abbreviated annual review is conducted, a signed certification is an acceptable substitute record for Form GS 1640.020-1. A copy of the form or signed certification shall be filed with the Integrity Management records.

When the MAOP of a pipe segment is revised, all corresponding records shall be kept for the life of the pipeline segment. A copy of the study required by this procedure shall be kept with the MAOP records.

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EXHIBIT A
(1 of 6)

Instructions for Completion of Form GS 1640.020-1 "Annual Class Location Verification."

The following items are keyed to Form GS 1640.020-1 "Annual Class Location Verification," page 5 of this exhibit. Form GS 1640.020-1 should correspond to related Form GS 1640.010-1 "Class Location Study." Each blank must be completed as it relates to the pipeline covered by the Class Location Study. If the information to enter on the form is "none" or "not applicable," then insert "N/A" in the appropriate blank. If the information is unknown, enter "unknown" in the appropriate blank.

Key	Item	Description
1	Company	Choose from drop-down list.
	Pipeline Location Information	
2	Piping System Name	Indicate Piping System Name (refer to GS 2100.015 "Piping System Names and Identifiers").
3	Piping System/Segment ID	Indicate Piping System Identifier (refer to GS 2100.015 "Piping System Names and Identifiers") and Piping Segment Identifier, if applicable (refer to GS 1660.020 "Documentation of Maximum Allowable Operating Pressure").
4	Section ID	Assign an identification number or letter or combination thereof, which corresponds to the particular section of pipeline covered by this form.
5	Map Reference(s)	List the various operations map(s), GIS grid(s), transmission map(s), etc.
6	Length of Section	Length of section in feet.
7	Station and/or Location Information	If available, indicate the pipeline stationing (from station, to station) for the pipeline. If stationing is not available, provide a location description (e.g., starting 510' west of the centerline of County Line Road, ending 1200' east of Dutch Ridge Road, Trenton Township, Clark County).

EXHIBIT A
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Key	Item	Description
	Population Density and Class Location	
8	Has an Increase in the Population Density Resulted in a Change in Class Location?	This answer shall be based on the field verification and updated class location study map(s).
9	Effective Date of Population Density Increase (if Resulting in a Change in Class Location)	If a population density increase results in a change in class location, enter the date that the new structure and/or outside area was open for human occupancy. If more than one new structure and/or outside area, enter the date when the population density affected the existing Class Location.
10	Description of Area Affected by the Population Density Increase (if Resulting in a Change in Class Location)	If a population density increase results in a change in class location, enter location information if population density increase is clustered or impacted by a commercial building.
11	Description of Any Physical Barriers or Other Factors Which May Limit Further Expansion of the More Densely Populated Area (if Resulting in a Change in Class Location)	If a population density increase results in a change in class location, identify railroad tracks, rivers, interstates, etc. that may limit further expansion. If there appears to be no limit, then consider additional development that may further change the existing class location. This may be helpful if remediation is required.
12	Previous Class Location	Choose appropriate Class Location from drop-down list, as determined by previous Class Location Study or Annual Verification.
13	Present Class Location	Choose appropriate Class Location from drop-down list based on maps showing population density, as defined and directed by GS 1640.010 “Class Location Determination for Transmission Lines.”
	Pipeline Design Data	
14	MAOP	Indicate the existing Maximum Allowable Operating Pressure (MAOP) of the pipeline.
15	Hoop Stress (%SMYS) produced by the MAOP	Display the hoop stress (%SMYS) produced by the MAOP.

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Supersedes: 01/01/2014		Page 8 of 11

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(3 of 6)

Key	Item	Description
	Pipeline Design Data	
16	Class 1 72% SMYS	Display 72% SMYS.
17	Class 2 60% SMYS	Display 60% SMYS.
18	Class 3 50% SMYS	Display 50% SMYS.
19	Class 4 40% SMYS	Display 40% SMYS.
20	Is the Present Class Location commensurate with the Established MAOP?	Self-explanatory.
	Code Requirements	
21	Are the current code requirements with respect to design, construction, and testing different from the code requirements followed at the time of installation?	Refer to the instructions for completing Form GS 1640.010-1 “Class Location Study,” Key 33 for information on versions of the Federal Code and their effective dates.
	Physical Condition of Pipeline	
22	#Leaks found during the past year #Leaks open #Dig-ins #Dents, Gouges, Scratches or other pipe defects reported	Research applicable records and indicate the appropriate information. Attach copies of applicable records.
	Operating and Maintenance History	
23	Patrolling	Research patrolling records and indicate the appropriate patrolling schedules based on the Class Location.
24	Leak Surveys	Research leak survey records and indicate the appropriate leak survey schedule based on Class Location and Odorization.

EXHIBIT A
(4 of 6)

Key	Item	Description
	Operating and Maintenance History	
25	Cathodic Protection	Research cathodic protection records and indicate the appropriate information.
26	Right-of-Way	Talk to personnel responsible for patrolling, leak surveying, and/or updating the Class Location Study and indicate the appropriate information.
27	Maximum Actual Operating Pressure	Research piping system pressure recording information for the highest operating pressure that occurred during normal operations within the past year.
28	Hoop Stress Produced by Maximum Actual Operating Pressure	Calculate % SMYS produced by the Maximum Actual Operating Pressure.
	Confirmation or Revision of MAOP	
29	Required Actions	Determine appropriate actions that may be taken to confirm or revise the MAOP according to GS 1640.020 “Annual Class Location Verification” Section 3.
30	Above Action to be Taken	Indicate the recommended action to be taken to confirm or revise MAOP.
	Review and Approval	
31	Prepared By:	Print or type name and title of person who prepared Form GS 1640.010-1. The form must be completed by an Engineer or Engineering Technician. The preparer must also sign on the “signature” line. Indicate the date that Form GS 1640.010-1 was prepared.
32	Reviewed By:	Print or type name and title of person who reviewed Form GS 1640.010-1. The form must be reviewed by an Engineer. The Engineer that prepared the form may be the same Engineer that reviewed the form. The reviewer must also sign on the “signature” line. Indicate the date that Form GS 1640.010-1 was reviewed.

EXHIBIT A
(5 of 6)

ANNUAL CLASS LOCATION VERIFICATION

Company <CHOOSE FROM LIST> (1)			
Pipeline Location Information			
Piping System Name (2)	Piping System/Segment ID (3)	Section ID (4)	Map Reference(s) (5)
Length of Section (6)	Station and/or Location Information From: To: (7) Location:		
Population Density and Class Location			
Has an Increase in Population Density Resulted in a Change in Class Location? ☐ No ☐ Yes (8)		Effective Date of Population Density Increase (if Resulting in a Change in Class Location) (9)	
Description of Area Affected by the Population Density Increase (if Resulting in a Change in Class Location) (10)			
Description of Any Physical Barriers or Other Factors Which May Limit Further Expansion of the More Densely Populated Area (if Resulting in a Change in Class Location): (11)			
Previous Class Location: <CHOOSE FROM LIST> (12)		Present Class Location: <CHOOSE FROM LIST> (13)	
Pipeline Design Data			
MAOP (14)		Hoop Stress Produced by the MAOP (15)	
Class 1 72% SMYS (16)	Class 2 60% SMYS (17)	Class 3 50% SMYS (18)	Class 4 40% SMYS (19)
Is the Present Class Location Commensurate with the Established MAOP? ☐ **Yes** ☐ **No** If yes, skip to Review and Approval Section. If no, continue with all sections below. (20)			
Code Requirements			
Are the current code requirements with respect to design, construction, and testing different from the code requirements followed at the time of installation? ☐ No ☐ Yes If yes, explain (21)			
Physical Condition of Pipeline			
# Leak(s) Found during the past year: Grade 1 Grade 2 Grade 3 # Leak(s) Open: Grade 1 Grade 2 Grade 3 # Dig-ins: # Dents, Gouges, Scratches or other pipe defects reported: (22) Attach applicable leak reports, failure reports, etc.			
Operating and Maintenance History			

Patrolling: Has the pipeline been patrolled to observe line marker requirements and surface conditions for leakage or construction activity or other factors affecting safety and operations in accordance with the following:

Class Location	At highway and railroad crossings	At all other places
1 and 2	7 ½ months; but at least twice each calendar year? ☐ Yes ☐ No ☐ N/A	15 months, but at least once each calendar year? ☐ Yes ☐ No ☐ N/A
3	4 ½ months; but at least four times each calendar year? ☐ Yes ☐ No ☐ N/A	7 ½ months, but at least twice each calendar year? ☐ Yes ☐ No ☐ N/A
4	4 ½ months; but at least four times each calendar year? ☐ Yes ☐ No ☐ N/A	4 ½ months, but at least four times each calendar year? ☐ Yes ☐ No ☐ N/A

Observations During Patrol(s): (23)

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Distribution Operations

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ANNUAL CLASS LOCATION VERIFICATION

Leak Surveys: Has the pipeline been leak surveyed in accordance with the following:

Class Location & Odorization:	**Leak Survey Schedule Not to Exceed:**
All Class Locations, Odorized Gas	15 months, but at least once each calendar year? ☐ Yes ☐ No ☐ N/A
Class Location 1 or 2, Non-Odorized Gas	15 months, but at least once each calendar year? ☐ Yes ☐ No ☐ N/A
Class Location 3, Non-Odorized Gas	7 ½ months, but at least twice each calendar year? ☐ Yes ☐ No ☐ N/A
Class Location 4, Non-Odorized Gas	4 ½ months, but at least four times each calendar year? ☐ Yes ☐ No ☐ N/A

Observations During Leak Surveys: (24)

Cathodic Protection: Has cathodic protection been maintained? ☐ Yes ☐ No ☐ N/A

Comments: (25)

Right-of-Way: Has the right-of-way been cleared within the past 12 months? ☐ Yes ☐ No ☐ N/A
Does the right-of-way require clearing? ☐ Yes ☐ No ☐ N/A
Are there any encroachments along the right-of-way? ☐ Yes ☐ No ☐ N/A

Comments: (26)

Maximum Actual Operating Pressure	**Hoop Stress Produced by Maximum Actual Operating Pressure**
(27)	(28)

Required Actions

This segment of pipeline has been reviewed in accordance with the requirements of 49 CFR Parts 192.609 and 192.611 and is judged to be qualified for operation in class location at:

a. MAOP of psig if no further action is taken, or
b. MAOP of psig if the following action is taken:
   i. ☐ Completion of a test to at least psig for a minimum of 8 hours, or
   ii. ☐ Completion of the following remedial work

(29)

Above Action to be Taken:
☐ a ☐ b (30)

Review and Approval

Prepared By:

Name	Title	(31)	Signature	Date

Reviewed By:

Name	Title	(32)	Signature	Date

Distribution Operations

Gas Standard

Effective Date: 01/01/2014	**Continuing Surveillance**	Standard Number: **GS 1650.010**
Supersedes: 01/01/2013		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE: 49 CFR Part 192.613

1. GENERAL

The Minimum Federal Safety Standards requires the Company to have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning:

a. changes in class location,

b. failures,

c. leakage history,

d. corrosion, including substantial changes in cathodic protection requirements, and

e. other unusual operating and maintenance conditions.

The Company has procedures for collecting and recording information about gas leaks, the condition of its underground gas system and changes in class location. This information is collected on a continuing basis and is used as a basis for the maintenance, retirement, renewal or alteration of the Company's gas pipelines, both transmission and distribution.

If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the Company shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with GS 1660.010 or GS 1660.010(PA) "Maximum Allowable Operating Pressure."

2. CONTINUING SURVEILLANCE PROCEDURES

The following list of gas standards or plans comprises the Company's continuing surveillance procedure.

Effective Date: 01/01/2014	Continuing Surveillance	Standard Number: **GS 1650.010**
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Continuing Surveillance Procedures

GS Number / Plan	Title
GS 1100.010(XX)	Locating Gas Facilities
GS 1100.020	Damage Prevention – Blasting Activities
GS 1410.010	Metallic Pipeline Exposures
GS 1430.020(XX)	External Corrosion Control Monitoring
GS 1430.030(XX)	Active Corrosion
GS 1440.010(XX)	Internal Corrosion Inspection Requirements
GS 1440.020	Internal Corrosion Monitoring
GS 1450.010(XX)	Atmospheric Corrosion
GS 1640.020	Annual Class Location Verification
GS 1652.003(XX)	Program for Investigation of Failures
GS 1652.010	Investigation of Failures
GS 1670.020(XX)	Odor Level Monitoring
GS 1702.010(XX)	Patrolling Distribution Systems
GS 1704.010(XX)	Patrolling Transmission Lines
GS 1708.020(XX)	Leakage Surveys
GS 1760.010(XX)	Critical Valve Inspection and Maintenance
GS 1780.010	Cast Iron - General
DIMP (XX)	Distribution Integrity Management Plan
DPP (XX)	Damage Prevention Plan
TRIMP (XX)	Transmission Integrity Management Plan

The (XX) indicates that state specific version for the gas standard exists.

Effective Date: 01/01/2013	Program for Investigation of Failures	Standard Number: GS 1652.003
Supersedes: N/A		Page 1 of 2

Companies Affected:

☑ NIPSCO	☑ CGV	☐ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.617

1. GENERAL

This procedure establishes a method for analyzing accidents and failures associated with an in-service **pipeline**, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, and for determining the cause of the accident or failure and minimizing the possibility of a recurrence.

For the purpose of this procedure the following definitions apply.

a . "Failures" are ordinarily deficiencies in material design, construction, operation and maintenance on or to in-service pipelines.

b. "Accidents" are unexpected and undesirable events occurring on or to in-service pipelines.

2. INVESTIGATIONS OF FAILURES AND ACCIDENTS

The level of investigation of a failure or accident will depend upon the situation. A failure or accident resulting in or involved with a DOT reportable **incident** shall require a detailed investigation. A failure or accident not associated with a DOT reportable **incident** shall be investigated at a sufficient level to determine appropriate action.

2.1 DOT Reportable Incidents

As soon as the incident site has been made safe, rapid response will be necessary for preserving the integrity of specimens and gathering information pertinent to the investigation. If the cause of the accident or failure is not readily identifiable, the Company should take care to maintain the incident site in as undisturbed a condition as possible until further investigation may be undertaken.

The Company should take the following actions in conducting a field investigation as to the cause of the failure or accident.

a. Obtain or develop a list of the personnel, equipment, and witnesses involved in the event.

b. Obtain or develop a chronological list of events.

c. Take photographs of site and/or equipment.

d. Preserve evidence.

e. Determine if tests are needed and whether laboratory analysis or outside consultants are warranted to determine the cause of failure. Refer to Section 3 for guidance on testing of specimens.

Once the investigation is completed the Company should determine the cause of the failure or accident. The need for continuing surveillance of pipeline facilities should also be determined.

The cause of the failure or accident shall be used to meet the reporting requirements detailed in GS 1020.020 “Incident Reporting”.

2.2 Other Failures and Accidents

Investigation of a failure or accident not associated with a DOT reportable **incident** should be at a sufficient level to determine the cause.

3. RECORDS

Testing of the specimen should be considered when:

a. Questions exist as to the cause (why) of failure.

b. Questions exist as to the method (how) of failure.

c. The failure resulted in a DOT reportable **incident**.

d. Litigation is likely.

The testing methods used should be suited to the particular material being tested and be pertinent to the failure investigation.

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Gas Standard

Effective Date: 04/01/2011	Investigation of Failures	Standard Number: **GS 1652.010**
Supersedes: 05/01/2010		Page 1 of 6

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

This standard establishes a method for analyzing failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

For the purpose of this standard, "failures" are ordinarily deficiencies in material design, construction, operation and maintenance, associated with:

a. an in-service **pipeline**,

b. materials identified as being defective prior to being placed in-service, such as in the warehouse, during installation, or during testing, or

c. tools and equipment**.**

Note: Failures involving fleet vehicles and equipment (e.g., backhoes, trenchers, trucks, trailers, compressors) should be reported through Fleet Maintenance and Services.

2. REPORTING CRITERIA

Form GS 1652.010-1, “Facility Failure Report” (see Exhibit A), shall be submitted for failures on components that are part of an in-service pipeline facility, such as:

a. construction or material defect,

b. cracks in welds,

c. defective fusion joints, or

d. cracks in the body or components of steel, plastic or cast iron pipe.

A Facility Failure Report must be submitted for each failure of a mechanical fitting. “Mechanical fitting” means a mechanical device used to connect sections of pipe. The term mechanical fitting applies only to (a) Stab Type fittings; (b) Nut Follower Type fittings; (c) Bolted Type fittings; or (d) Other Compression Type fittings. The reporting requirements apply to failures in the bodies of mechanical fittings, failure in the joints between the fitting and the pipe, and when pipe pulls out of the fitting. Mechanical fitting failures must be reported regardless of the result of any cause, including but not limited to excavation damage, exceeding fitting service life, poor installation practice, and incorrect application. Mechanical fitting are to be reported regardless of the materials they join. Report mechanical fittings that join steel-to-steel, steel-to-plastic, and plastic-to-plastic. Specific examples of mechanical fittings to be reported include, but are not limited to, transition fittings, risers, compression couplings, stab fittings, mechanical saddles, mechanical tapping tees, service tees, sleeves, ells, wyes and straight tees.

Other failures (i.e., failures not listed above) found during normal operations, such as leak repairs, regulator maintenance, valve inspection, etc., may have a Facility Failure Report submitted in addition to any other reporting requirements.

Facility Failure Reports also may be required as part of the investigation of reportable incidents, damage to company pipeline facilities, employee injury/illness notification and reporting, and/or public injuries/property damage notification/reporting.

Facility Failure Reports should be submitted for failures that are associated with materials that are not in-service or for tools and equipment, so that these types of failures can be tracked and resolved for safety, economic, and operational reasons.

3. REPORTING AND ROUTING

Form GS 1652.010-1, "Facility Failure Report," and the on-line Facility Failure Reporting System shall be used to document and track failures and investigations.

3.1 Front Line Worker

A Facility Failure Report shall be initiated at the work location experiencing the failure. The person preparing the Facility Failure Report should write a narrative description of the failure stating what happened, how the failure was discovered and what action, if any, was taken to correct it. The report shall contain pertinent facts about the failure.

The Facility Failure Report and additional information (e.g., drawings, pictures, etc.), when appropriate, shall be forwarded to the front line leader/supervisor for review.

3.2 Front Line Leader/Supervisor

When it has been determined that a facility failure resulted in or is involved with personal injury, significant property damage to others, or a reportable incident, the appropriate notifications (e.g., OCM, GM, Compliance Manager, Communications, Legal), shall be made for guidance for conducting the investigation, reporting the failure, and retaining or disposal of the material involved.

The failed item shall be retained at the reporting location. The item shall be tagged with the date of failure and address or other identifying information. Contact Gas Standards for guidance on disposal of failed items that are not involved in a legal or insurance claim.

It is permissible to include multiple failures on one Facility Failure Report; however, all failures, regardless of frequency or prior reports, shall be reported.

The front line leader/supervisor shall review the Facility Failure Report to assure that pertinent information is included. The front line leader/supervisor, or designee, shall enter the report information onto the on-line Facility Failure Reporting System.

4. INVESTIGATION

Gas Standards will assign an investigator (e.g., standards engineer or specialist, technical specialist) to coordinate the investigation and testing of the failed part, if necessary. The investigator is responsible for obtaining the failed part (if applicable), gathering additional information, engaging internal or external specialists, and deciding if any testing is needed to determine the cause of the failure. When the investigation has been completed, the investigator is also responsible for returning the findings and recommendations to Gas Standards. Gas Standards will further distribute the findings and recommendations to appropriate personnel.

The following types of in-service failures shall be considered for further examination:

a. repeat of similar material failure or construction defect type leaks occurring in the same general area or same year of construction,

b. cracked welds or fusion joints,

c. crack(s) in the body of pipe or fittings,

d. graphitization or cracking of cast-iron pipe, or

e. manufacturing defect in a pipeline component.

5. RECORDS

Facility Failure Reports shall be entered into the on-line Facility Failure Reporting System and maintained for a minimum of three years after resolution or the life of the pipeline, whichever is greater.

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EXHIBIT A (1 of 3)

Report Type[1]
- ☐ In-Service
- ☐ Not In-Service
- ☐ Tool / Equipment

FACILITY FAILURE REPORT

Company[2]	
Date Failed / Found[3]	
Location Number[4]	
Form Completed By[5]	

FAILURE LOCATION

Address[6]	Cust. ID/Site ID/PSID[7]	Municipality[8]	Map/GIS Grid Number[9]

FAILURE INFORMATION

Failed Item Stored At[10]	Contact Person[11]	Contact Number[12]

THIS SECTION IS NOT APPLICABLE FOR TOOL/EQUIPMENT REPORTS

Detected By (Circle One)[13]
A. Leakage Survey
B. Customer/Public
C. Pressure Gauge
D. Other Company Activity

Suspected Cause[14]
(Check One on Reverse Side)

Facility Type (Circle One)[15]
A. Distribution Main
B. Transmission Line
C. Service Line
D. Meter Set
E. Pressure Regulating Facility
F. Other

Related Leak Order Number (If Applicable)[16]

Leak Grade (Circle One)[17]
A. Grade 1
B. Grade 2+ (CDC Only)
C. Grade 2
D. Grade 3
E. No Leak
F. Unknown

Leak Location 18
(Pick one for each of items 18a, 18b and 18c on reverse side)

Complete this section for failed plastic pipe

Method of Installation[19]	Soil Type in Contact w/ Pipe[20]
(Check One on Reverse Side)	**(Check One on Reverse Side)**

Operating Pressure At Time of Failure[21]	Operating Pressure Normal Range[22]

PRODUCT INFORMATION

Product Type[23]	Manufacturer[24]	Model Number / Print Line /Other Markings[25]
(Circle One on Reverse Side)		

Year Installed (If Known)[26]	Year Manufactured (If Known)[27]	Material Size[28]	Item Description[29]

Related Work Order Number[30]

Material Type (Circle One)[31]
A. Metallic **B. Plastic**

DESCRIPTION OF FAILURE[32]

FIELD ACTION TAKEN / RECOMMENDATION(S)[33]

FRONTLINE LEADER / SUPERVISOR[34]

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**EXHIBIT A
(2 of 3)**

SUSPECTED CAUSE[14]

○ External Corrosion	○ Temperature	○ Vehicle Damage	○ Defective Fitting	○ Malfunction of Pressure Regulating Equipment
○ Internal Corrosion	○ High Winds	○ Rupture of Previously Damaged Pipe	○ Defective Steel Weld	○ Miscellaneous
○ Earth Movement	○ Operator Excavation Damage	○ Vandalism	○ Defective Plastic Fusion	○ Unknown
○ Lightning	○ 3rd Party Excavation Damage	○ Defective Body of Pipe	○ Defective Pipe Seam	
○ Rains / Floods	○ Fire / Explosion		○ Operator Error	

Leak Location[18a]
(all leak Grades, if applicable)
○ Main-to-Main ○ Service-to-Service
○ Main-to-Service ○ Meter Set

Leak Location[18b]
○ Above Ground ○ Below Ground

Leak Location[18c]
○ Inside ○ Outside

Method of Installation[19]
○ Open Trench ○ Joint Trench
○ Bored ○ Plowing - Plant-in
○ Plowing - Pull-in ○ Unknown
○ Insertion

Soil Type in Contact W/ Pipe[20]
○ Sand ○ Rocky
○ Loam ○ Slurry
○ Clay

PRODUCT TYPES[23]

A. Regulators
- Regulators Under 2"
- Regulators 2" and Over Self-Operated
- Regulators 2" and Over Instrument Control
- Regulators 2" and Over Pilot Operated

B. Meters
- Domestic
- Large Volume Displacement
- Large Volume Turbine
- Large Volume Rotary

C. Regulators / Meter Auxiliary Equipment
- Pressure Gauges - Recording (Chart Drives)
- Pressure Gauges non-recording
- Controllers
- Heaters
- Domestic Meter Settings
- Remote Indexes / Readers
- Service Risers - Anodeless (Plastic Carrier)
- Service Risers - Steel
- Other

D. Odorizers
- Odorizer Equipment

E. Metallic Pipe
- Bare Steel
- Coated Steel
- Cast Iron
- Wrought Iron
- Ductile Iron
- Copper

E. Plastic Pipe
- ABS
- CAB
- PVC
- MDPE-2306
- MDPE-2406
- MDPE-2406/2708
- MDPE-2708
- HDPE-3306
- HDPE-3408
- HDPE-3408/3608
- HDPE-3408/4710
- HDPE-3608
- HDPE-4710
- Other

G. Mechanical Joining Fittings
- Boltless Mechanical Fitting (Compression) Metallic
- Boltless Mechanical Fitting (Compression) Plastic
- Bolted Couplings (Compression) Metallic
- Bolted Couplings (Compression) Plastic
- Stab Fitting - Plastic (e.g., Lycofit, Metfit)

H. Other Fittings
- Plastic Fusion-Socket
- Plastic Fusion-Butt
- Plastic Fusion-Electrofusion
- Transition Fittings
- Steel Weld Fittings
- Flanges
- Line Stopping Fittings
- Threaded Fittings

I. Valves
- Main-Plastic
- Main-Metallic
- Curb Valve-Plastic
- Curb Valve-Metallic
- Meter Valve
- Excess Flow Valve

J. Tapping Tees
- Mechanical Base-Metallic
- Mechanical Base-Plastic
- Steel Weld Base
- Plastic Fusion Base

K. Repair Fittings
- Leak Repair Clamp-Mild Steel
- Joint Repair Clamp-Stainless
- Joint Repair-Mechanical
- Joint Repair-Non-Mechanical

L. Corrosion Control
- Coatings
- Tapes/Mastics
- Anodes
- Rectifiers
- Insulating Kits/Fittings

M. Tools / Equipment
- Hand Tools
- Power Hand Tools
- Pneumatic / Hydraulic Tools
- Water Pumps
- Portable Generators
- Instruments
- Tapping & Plugging Equipment
- Personal Protection Equipment
- Fire Extinguishers
- Other

N. Other
- Other

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EXHIBIT A
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Instructions Facility Failure Report Form GS 1652.010-1 Completion

Key Number	Field Name	Field Description
1	Report Type	Choose One: **In-Service** – Any gas component installed and in operation. **Not In-Service** – Any gas component prior to being placed in-service (e.g., found in warehouse, found during pressure test). **Tool/Equipment** – Hand Tools, Pneumatic/Hydraulic Tools,Instruments, Personal ProtectionEquipment, **NO FLEET VEHICLES SUCH AS TRUCKS, COMPRESSORS, BACKHOES, TRENCHERS, TRAILORS**
2	Company	Gas Company Name (e.g., NIPSCo, CPA, CMA).
3	Date Failed/Found	Date that the failure occurred or was discovered MM/DD/YYYY.
4	Location Number	2-4 digit number representing Indiana's local operating area (LOA), Columbia's local area location number, or CMA number corresponding to the address of office location.
5	Form Completed By	Person's name filling out the form in the field.
6	Address	Location (e.g., address, intersection) of failure.
7	Cust. ID/Site ID/PSID	If applicable or known, the customer identification number relating to a failure on a service line or meter setting.
8	Municipality	City, town, borough, etc. where failure occurred.
9	Map/GIS Grid Number	Map number or Geographical Information System (GIS) grid number where failure occurred.
10	Failed Item Stored At	The location where the failed item can be found (e.g., office or field location if unable to physically remove).
11	Contact Person	Name of the person that can be contacted to obtain more information (e.g., the person filling out the report, the person who discovered the failure, the front line leader/supervisor).
12	Contact Number	Telephone number (cell or office) of the contact person.
13	Detected By	Circle only one of the options indicating how the failure was found. Not applicable for Tools/Equipment reports. If "Other Company Activity", describe in Description of Failure field (32).
14	Suspected Cause	Check only one of the options on Page 2 of the form indicating the suspected cause of the failure. Not applicable for Tools/Equipment reports. If "Miscellaneous", describe in Description of Failure field (32).
15	Facility Type	Circle only one of the options indicating the facility type that failed. Not applicable for Tools/Equipment reports. If "Other", describe in Description of Failure field(32).
16	Related Leak Order Number	Indicate the related leak order number from the leak order form (only applicable for Legacy Columbia Companies - DPI number, or NIPSCo – CIS ticket number).
17	Leak Grade	Circle only one of the options indicating the leak grade.
18	Leak Location	Pick one for each of items 18a, 18b and 18c, on page 2, indicating mechanical fitting leak location.
19	Method of Installation	Check one of the options on Page 2 indicating the original method of installation.
20	Soil Type in Contact W/ Pipe	Check one of the options on Page 2 of this form indicating the soil type.
21	Pressure at Time of Failure	Provide the operating pressure at the time of failure.
22	Normal Operating Pressure	Provide the Normal Operating Pressure Range of the pipe if known.
23	Product Type	Circle only one of the options on Page 2 of the form indicating the product type.
24	Manufacturer	Manufacturer name of the failed item, if known.
25	Model Number/or Print Line	Model Number of the failed item, if known, or the print line on plastic pipe or coated steel pipe coating, if available.
26	Year Installed	The year that the failed item was originally installed, if known.
27	Year Manufactured	The year that the failed item was originally manufactured, if known.
28	Material Size	Indicate the size of the failed item (e.g., size and units, 4" IPS, 1/2" CTS).
29	Item Description	Description of the item that failed, including size, material, facility type (e.g., 1" plastic curb valve, 4" coated steel pipe). If "Other", describe in Description of Failure field(32).
30	Related Work Order Number	Work order or job order number for the task or job being completed when the failure was found.
31	Material Type	Indicate the Material Type of the failed item as being metallic or plastic.
32	Description of Failure	Provide a detailed description of the failure (e.g., black plastic cap on 1" Plexco serv tee cracked & caused leakage).
33	Field Action Taken / Recommendations	Indicate any field action that was taken to address the situation (e.g., cracked plastic cap was removed and replaced with new plastic cap) or indicate any recommended action to be taken if failure was corrected by a temporary repair or if repair is to be addressed at a later date.
34	Front Line Leader/Supervisor	Name of front line leader/supervisor reviewing this report.

Form GS 1652.010-1 Instructions (04/2011)

Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Reporting of Mechanical Fitting Failures	Standard Number: **GS 1652.015**
Supersedes: N/A		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Parts 191.7, 191.12, 192.617, 192.1009, 192.1011, and PHMSA F-7100.1-2

1. GENERAL

This standard establishes a method for reporting Mechanical Fitting Failure Reports (MFFR) to PHMSA and to applicable state commissions.

For the purpose of this standard, MFFRs are facility failure reports (FFR) that additionally meet PHMSA requirements for annual reporting on PHMSA form F-7100.1-2. These FFRs are those involving mechanical fittings that result in Grade 1 leaks (hazardous).

All failures of mechanical fittings shall first be reported as FFRs and subsequently reported as MFFRs. For information on reporting of facility failures and the handoff of material for investigation, see GS 1652.010 “Investigation of Failures” and ON 13-03 “Facility Failure Reporting Process – Frequently Asked Questions (FAQ)”.

2. MECHANICAL FITTINGS

2.1 Type

Mechanical fittings consist of an elastomer seal and a gripping device to affect pressure sealing and/or pull-out resistance capabilities. Types of mechanical fittings include:

a. Stab fittings.

b. Nut follower fittings, sometimes called “boltless” mechanical fittings.

c. Bolted mechanical fittings.

d. Other compression-type fittings.

2.2 Examples

Examples of mechanical fittings of the above types include the following.

a. Plastic and metallic curb valves (i.e. Kerotest, Dresser, Perfection, Handley).

b. Couplings, ells, and tees with stab connections (i.e. Perfection, Continental).

c. Couplings, ells and tees with nut follower connections (i.e. Kerotest, Dresser).

d. Service head adapters on service risers where the failure is the body of the fitting or the internal stab or transition connection.

e. Bolted leak repair devices.

2.3 Additional Guidance

For the purpose of PHMSA reporting, a threaded connection is <u>not</u> considered to be a mechanical fitting.

PHMSA reporting requirements apply to all failures of the mechanical fitting, including

a. failures in the bodies of mechanical fittings,

b. failures in the joints between the fitting and the pipe, and

c. when the pipe pulls out of fitting.

Questions regarding whether a fitting is a mechanical fitting should be forwarded to Gas Standards.

3. REPORTING FAILURES INVOLVING MECHANICAL FITTINGS

Timely and accurate reporting of mechanical fitting failures involves persons working in the following roles. Responsibilities of each work role is as follows:

3.1 Front Line Workers and Contractors

Front line workers and contractors working for the Company are responsible for:

1. recognizing when a FFR involving a mechanical fitting is required,

2. completing the FFR (Form GS 1652.010-1), and

3. the timely delivery of the FFR and the failed material to the front line leader/supervisor or their designee.

3.2 Field Operations Leaders and Front Line Leaders

Front line leaders/supervisors or their designees are responsible for entering the FFR involving a mechanical fitting into the Facility Failure Reporting System/Database (FFDB) in a timely manner.

All FFRs that involve mechanical fittings shall be entered into the FFDB and the material made available for investigation on a continuous basis, with the last FFRs for the year entered no later than 15 calendar days after the close of the year in which the failure was found.

3.3 Facility Failure Investigators

Facility Failure Investigators are responsible for:

1. gaining possession of the materials,
2. completing the failure investigation, and
3. indicating the final determination in the FFDB of whether each failure is reportable as a MFFR.

All FFRs that involve mechanical fittings shall be investigated on a continuous basis throughout the year, with the last investigations involving mechanical fittings occurring no later than 45 calendar days after the close of the year in which the failure was found

3.4 Pipeline Safety & Compliance (Gas Standards)

Gas Standards is responsible for the extraction of MFFR data and reporting to PHMSA.

Reporting for the previous year’s failures involving mechanical fittings shall occur no later than March 15th.

4. RECORDS

MFFR data shall be maintained by Gas Standards for a minimum of 10 years.

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Gas Standard

Effective Date: 06/01/2016	Maximum Allowable Operating Pressure	Standard Number: **GS 1660.010**
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☐ CPA

REFERENCE 49 CFR Part 192.619, 192.621, 192.623

1. GENERAL

The purpose of this procedure is to set forth guidelines for establishing the Maximum Allowable Operating Pressure (MAOP) for a **pipeline**.

The MAOP of an existing, new, or uprated pipeline shall be determined by Engineering.

Whenever the MAOP of a system is to be increased it shall be done in accordance with the Company's applicable uprating or pressure testing gas standards.

For Columbia Companies, refer to Gas Standards Series 5500 "Uprating" for the applicable uprating gas standards.

For NIPSCO, refer to Gas Design Standards 480-0010 "Pressure Elevation – Mains" and 480-0020 "Pressure Elevation – Services" for applicable uprating gas standards.

The applicable pressure testing gas standards are GS 1500.010, GS 1500.010(MA), or GS 1500.010(OH) "Pressure Testing."

2. PIPELINES INSTALLED BEFORE NOVEMBER 12, 1970

Subject to the restrictions set forth in Section 4 below, the MAOP of a pipeline which was installed before November 12, 1970 is determined as being the highest of the following.

2.1 Highest Actual Operating Pressure

The highest actual operating pressure to which a pipeline was subjected during the 5 years preceding July 1, 1970, if it is in satisfactory condition, considering its operating and maintenance history.

2.2 Pressure Established After Uprating

The pressure established in accordance with the Company's uprating procedure.

2.3 Test Pressure

The pressure obtained by dividing the test pressure on a plastic pipeline by 1.5

provided the pipe was tested after July 1, 1965.

For steel pipeline operated at 100 psig or more, the pressure obtained by dividing the test pressure by 1.4 in Class 3 and Class 4 locations, by 1.25 in Class 2 locations, or by 1.1 in Class 1 locations, provided the pipe was tested after July 1, 1965.

3. PIPELINES INSTALLED AFTER NOVEMBER 11, 1970

Subject to the restrictions set forth in Section 4 below, the MAOP of a pipeline which was installed after November 11, 1970 is determined as being the lowest of the following.

3.1 Test Pressure

The pressure obtained by dividing the test pressure on a plastic pipeline by 1.5.

For steel pipeline operated at 100 psig or more, the pressure obtained by dividing the test pressure by 1.5 in Class 3 and Class 4 locations, by 1.25 in Class 2 locations, or by 1.1 in Class 1 locations.

3.2 Pressure Established After Uprating

The pressure established in accordance with the Company’s uprating gas standards.

4. ADDITIONAL LIMITATIONS ON CALCULATION OF MAOP FOR HIGH PRESSURE DISTRIBUTION SYSTEMS

Regardless of the date installed, the MAOP of a **high pressure distribution system** is determined as being the lowest of the following.

a. For furnace butt welded pipe 300 psig.
b. The lowest design pressure of the weakest element in the system, such as the working pressure of a curb valve, service regulator or shrink repair device.
c. 10 psig for a system where any services are equipped with a non-relief type regulator.
d. 99 psig for a system where services are equipped with single internal relief type service regulator.
e. 25 psig for cast iron pipe systems in which the bell and spigot joints are not completely reinforced.
f. The pressure to which a joint could be subjected without the possibility of parting.
g. The pressure determined to be the maximum safe pressure after considering the history of the system, particularly known corrosion and actual operating pressure. For example, the lowest of the above criteria may establish a MAOP which the operator feels is too high for safe operation of the system based on pipe condition or external loading.

5. LOW-PRESSURE DISTRIBUTION SYSTEMS

The Company will not operate a **low-pressure distribution system** at a pressure:

a. higher than that at which the operation of any connected and properly adjusted low-pressure gas-burning equipment is unsafe, or

b. lower than the minimum pressure to ensure safe and continuing operation of any connected and properly adjusted low-pressure gas-burning equipment.

The preferred range is 7" water column (w.c.) to 12" w.c. Low-pressure systems can be operated outside of the preferred range when warranted, especially during peak flow periods or for other operational needs. Any low-pressure system that must operate at 14" w.c. or greater during peak periods to meet minimum pressure requirements shall be reported to Engineering. Engineering shall evaluate the system for actions (e.g. orifice changes, system improvements) that would be necessary to permit operating the system at or below 14" w.c. at design (peak-day) conditions.

6. CHANGES TO MAOP

A change to MAOP of an existing transmission line or a change to MAOP that creates a transmission line must comply with GS 1640.020 “Annual Class Location Verification,” Section 3 “Confirmation or Revision of MAOP.”

7. OVERPRESSURE PROTECTION

The Company may not operate a pipeline with an MAOP determined by the limitation identified in Section 4.g. unless overpressure protective devices are installed in a manner that will prevent exceeding the allowable build up over the MAOP, as indicated in GS 1750.010 or GS 1750.010(VA) “Pressure Regulating Station Operation and Maintenance,” Table 1.

8. RECORDS

The Company shall document Maximum Allowable Operating Pressure (MAOP) records for each transmission line and distribution system, except for low pressure distribution systems. The MAOP records shall be kept for the life of each transmission line and distribution system. Refer to GS 1660.020 or GS 1660.020(OH) “Documentation of Maximum Allowable Operating Pressure.”

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Effective Date: 04/22/2013	**Documentation of Maximum Allowable Operating Pressure**	Standard Number: **GS 1660.020**
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Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☐ COH
	☑ CMA	☑ CPA

REFERENCE

1. GENERAL

The purpose of this standard is to provide guidance in establishing and documenting the **Maximum Allowable Operating Pressure** and **Maximum Operating Pressure** of a **pipeline**.

As the NiSource distribution companies move towards consistency, this gas standard will coexist with the distribution companies' current practices until new the new Company Geographical Information System (GIS) and/or Work Management (WM) are fully functional and transitions are completed. At that time, Company specific gas standards will be cancelled.

Maximum Allowable Operating Pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated.

Maximum Operating Pressure (MOP) is the highest pressure at which a **piping system** may be operated. This pressure will not exceed the design pressure of the weakest link in a piping system or established MAOP of any pipeline segment and includes all components or adjoining facilities.

Each piping system shall have a designated MOP and each pipeline segment shall have a designated MAOP. Engineering is responsible for establishing the MAOP and MOP for new and existing pipeline segments and piping systems.

Pipelines shall not be operated above the piping system MOP.

2. ESTABLISHING AND DOCUMENTING MAOP

Form GS 1660.020-1, "MAOP Worksheet" (see Exhibit A), shall be used to establish and document MAOP. The MAOP documentation established prior to implementation of this standard shall be valid until such time changes are needed to the documentation (e.g, uprating).

2.1 Piping Systems

Typically, an MAOP and MOP will be established and documented for an entire piping system. When new piping systems are installed, the work order and test pressure information are the documentation to be included with Form GS 1660.020-1 "MAOP Worksheet" to establish the MAOP.

When subsequent additions or changes to the piping system are intended to follow the established MAOP, the design and testing need only to be qualified to the established MAOP and the work referenced to the established piping system. No documentation changes to Form GS 1660.020-1 "MAOP Worksheet" are needed.

If subsequent additions or changes to the piping system are to be designed and tested to establish a different MAOP, a new segment(s) will be established and the work order and test pressure information shall be used to establish its MAOP. The piping system's MOP must be updated as necessary.

2.2 Pipeline Segments

It may be advantageous to establish and document MAOP by pipeline segments. Long range plans for uprating, separating, combining, and/or replacing sections of piping systems should be considered when determining if establishing and documenting MAOP by pipeline segments would help to reduce the operating and maintenance costs necessary to achieve future plans.

Pipeline segments may include, but are not limited to the following examples:

a. continuous pipeline between sectionalizing block valves on **transmission line**s,

b. an entire piping system,

c. newly constructed sections of pipeline, or

d. continuous pipeline with specific pressure test documentation.

The pipeline segment should be identified by the piping system identifier, along with a pipeline segment identifier, as shown:

AABBBCCCX, where

a. AABBBCCC = piping system identifier (for description of piping system identifier, see GS 2100.015 "Piping System Names and Identifiers"), and

b. X = pipeline segment identifier, consisting of one or more alphabetical characters, such as "A", "B", "C", "AB", etc.

If the pipeline segment consists of the entire piping system, then "X" is null.

2.3 Acceptable Sources of Documentation

Acceptable sources of MAOP documentation are pressure test chart(s), pressure recording chart(s) used during an uprate, work order(s), uprate certificate, printout of electronically recorded pressure information, test pressure and duration information on work order (WOMS, WMS, etc.), operation maps (to determine installation dates and material type), service regulator records, material specifications, or any other documentation deemed acceptable by the Company.

If other documentation deemed acceptable by the Company is used, it must have written approval by the Manager of Engineering, or equivalent. The acceptability of new types of documentation should be evaluated by the Compliance Manager.

Other supporting information, such as maps indicating the uprated facilities, piping system schematics, etc., can supplement the MAOP documentation.

2.3.1 For Pipelines Installed Prior To November 12, 1970

For pipelines installed prior to November 12, 1970, additional acceptable sources of MAOP documentation indicating the actual operating pressure of the pipeline from July 1, 1965 through July 1, 1970, include regulator inspection records and peak day pressure maps.

If acceptable sources of MAOP documentation are not available, the MAOP may be established by the following methods.

a. An operator, familiar with the leakage and pressure operation of the pipeline, may furnish a signed certification indicating the MAOP and justification. If such a certification is used for determining the MAOP, it must be approved by the Manager of Engineering, or equivalent. This alternative applies only when originally establishing the MAOP.

b. The pipeline may be uprated in accordance with applicable gas standards.

2.4 Low-Pressure Distribution Systems

A **low-pressure distribution system** does not require an *MAOP Worksheet*. It is sufficient to designate a low-pressure distribution system by including the term “low pressure” (i.e. LP) in the piping system name.

3. ESTABLISHING AND DOCUMENTING MOP

Engineering shall review all MAOP documentation that is part of the piping system to establish the MOP of the piping system. The MOP shall be no greater than the lowest MAOP of all of the pipeline segments comprising the piping system.

Until the new Company Work Management/Geographical Information System (WM/GIS) is fully implemented, Engineering shall develop a method to document and communicate MOPs for piping systems that are comprised of pipeline segments with different documented MAOPs.

When GIS is fully implemented, GIS will require a number greater than or equal to 1.0 to designate MAOP/MOP, so MAOP and MOP for low-pressure distribution systems will be represented as 14” w.c.

See Exhibits B and C for illustrations of MAOP and MOP for pipeline segments contained within a piping system.

4. CHANGES TO MAOP OR MOP

When the MAOP of an existing pipeline segment is to be increased, it shall be done in accordance with the Company’s applicable uprating or pressure testing gas standards. It is permissible to re-document MAOP based on previous pressure test documentation for pipelines installed and pressure tested after July 1, 1965.

When changes are made to MAOP and/or MOP by uprating, derating, separating or combining a piping system(s), Field Engineering should ensure the completion of the following, as necessary.

a. Establish the appropriate MAOP(s) and/or MOP.

b. Update the MAOP and/or MOP piping system records.

c. Update the related customer computer database (e.g., DIS or GIS).

d. Notify Systems Planning to update the model.

e. Notify the appropriate measurement and regulation personnel to update the necessary regulator and meter station records (e.g., regulators supplying the affected system, as well as regulators supplied by the affected system).

f. For distribution owned transmission lines, complete a class location review according to the Company’s applicable gas standards.

5. RECORDS

Engineering shall maintain a file of each MAOP record and the supporting documentation used to establish the MAOP. MAOP records shall be retained for the life of the pipeline. A superseded Form GS 1660.020-1 “MAOP Worksheet” should be marked “void” and retained in the appropriate MAOP record file.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/22/2013	Documentation of Maximum Allowable Operating Pressure	Standard Number: GS 1660.020
Supersedes: 01/01/2013		Page 5 of 7

EXHIBIT A

MAOP WORKSHEET

COMPANY ______________________ PIPING SYSTEM NAME ______________________

ESTABLISHED MAOP ______________________ PIPING SYSTEM ID ______________________

PIPELINE SEGMENT ID ______________________

PRESSURE[1]	CRITERIA	SOURCE[2]
Section I - For pipeline segments installed before November 12, 1970:		
	a. The pressure obtained by dividing the test pressure on plastic pipe by 1.5.	
	b. For steel pipe operated at 100 psig or more, the pressure obtained by dividing the test pressure by 1.4 in Class 3 and Class 4 locations, by 1.25 in Class 2 locations, or 1.1 in Class 1 locations.	
	c. For steel pipe operated below 100 psig, the test pressure or 99 psig, whichever is less.	
	d. The highest actual operating pressure to which it was subjected during the 5 years preceding July 1, 1970. Note: If test pressures for Items a, b, and c occurred after July 1, 1965, then Item d is not applicable (N/A).	
Section II - For pipeline segments installed after November 11, 1970:		
	e. The test pressure on reinforced thermosetting plastic pipe (such as Red Thread®) within the pipeline segment divided by a factor of 1.5 or 99 PSIG, whichever is less.	
	f. The pressure obtained by dividing the test pressure on plastic pipe by 1.5.	
	g. For steel pipe operated at 100 psig or more, the pressure obtained by dividing the test pressure by 1.5 in Class 3 and Class 4 locations, or by 1.25 in Class 2 locations, or by 1.1 in Class 1 locations.	
	h. For steel pipe operated below 100 psig, the test pressure or 99 psig, whichever is less.	
Section III - Regardless of the date installed:		
	i. 300 PSIG for furnace butt welded pipe.	
	j. For steel pipe, the design pressure determined in accordance with the design formula for steel pipe.	
	k. 56 PSIG[3] for a pipeline segment containing 1¼" CTS 0.090" wall thickness medium density polyethylene pipe (used only at BSG/NU).	
	l. 60 PSIG[3] for a pipeline segment with medium density polyethylene pipe.	
	m. 99 PSIG[3] for a pipeline segment with high density polyethylene pipe.	
	n. The lowest design pressure of the weakest element in the pipeline segment, such as the working pressure of a curb valve, service regulator or LP shrink sleeve repair device.	
	o. 10 PSIG for a pipeline segment where services are equipped with a non-relief type service regulator.	
	p. 60 PSIG for a pipeline segment where services are equipped with a single internal relief type service regulator with a 3/16" orifice.	
	q. 99 PSIG for a pipeline segment where services are equipped with a single internal relief type service regulator with a 1/8" orifice.	
	r. 25 PSIG for a pipeline segment with cast iron pipe in which the bell and spigot joints are not completely reinforced.	
	s. The pressure limit to which a joint could be subjected without the possibility of parting.	
	t. The pressure determined to be the maximum safe pressure after considering the history of the pipeline segment, particularly known corrosion and actual operating pressure. For example, the lowest of the above criteria may establish an MAOP which the operator feels is too high for safe operation of the pipeline segment based on pipe condition or external loading. Document reasons for "t" or any other special circumstances.	
	Indicate the lowest value of Items a through t.	
	Established MAOP. If the established MAOP is different than the lowest value of Items a through t, then provide appropriate justification (e.g. uprate documentation) with engineering manager approval.	

COMPILED BY:	DATE:	REVIEWED BY: (ENGINEER)	DATE:

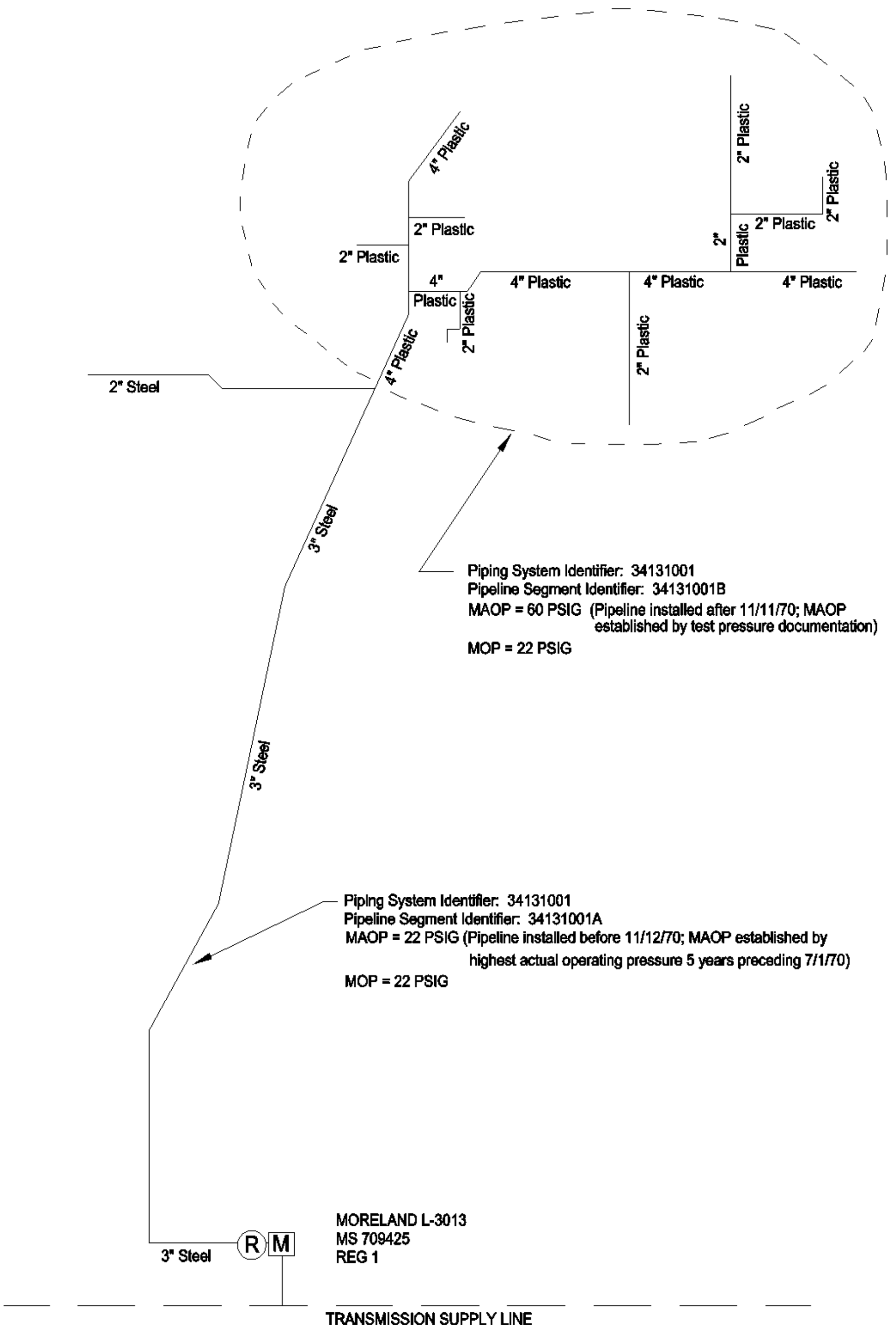
1 Complete each section in the pressure column by indicating the pressure information, not applicable (N/A), or unknown, as appropriate.
2 All source documents are to be attached or adequately referenced when part of permanent files.
3 Design pressure calculated using 73°F.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/22/2013	Documentation of Maximum Allowable Operating Pressure	Standard Number: GS 1660.020
Supersedes: 01/01/2013		Page 6 of 7

EXHIBIT B

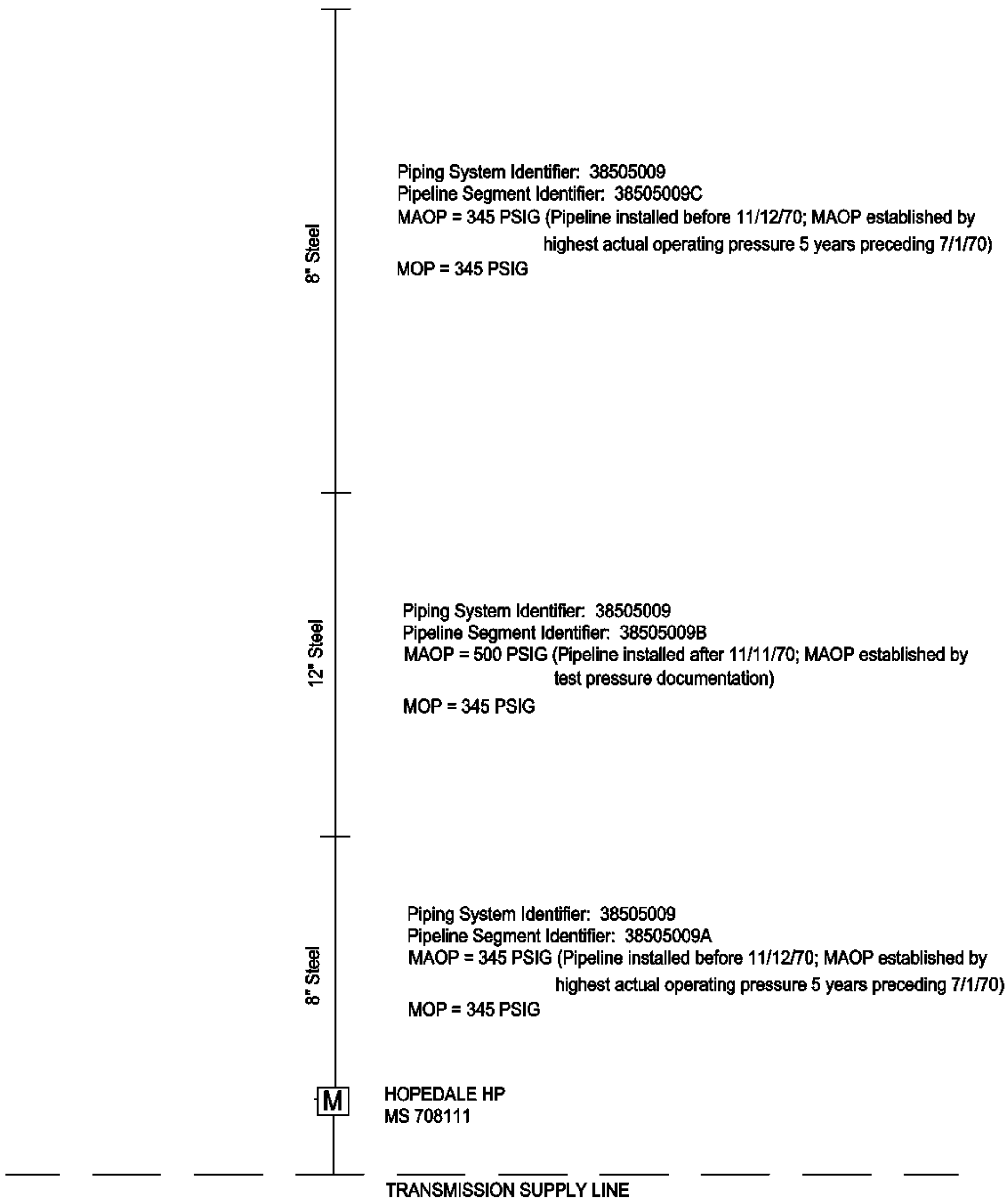


Distribution Operations

Gas Standard

Effective Date: 04/22/2013	Documentation of Maximum Allowable Operating Pressure	Standard Number: **GS 1660.020**
Supersedes: 01/01/2013		Page 7 of 7

EXHIBIT C



NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Odorant and Odorization Equipment Inspection and Maintenance**	Standard Number: **GS 1670.010**
Supersedes: 01/01/2010		Page 1 of 8

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

All odorant injected into the pipeline systems shall not be harmful to persons, materials or pipe.

The combustion product of odorant shall not be toxic when breathed or corrosive to material exposed to the combustion products.

The odorant shall not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

The purpose of the remaining procedure is to establish a program for inspecting and maintaining odorization equipment.

Equipment used by the Company for odorization shall be such that it introduces the odorant without wide variations in the level of odorant.

2. INSPECTION

Odorizers shall be inspected on a monthly basis, with the exception of individual customer odorizers (see Section 2.1). However, odorization facilities should be inspected more frequently if local knowledge of operating conditions indicates that more frequent inspection is necessary.

The inspection of odorization equipment shall consist of the following items.

a. Check the odorant level (i.e., is it time to schedule an odorant delivery?).

b. Examine the equipment and lines for odorant leakage.

c. If applicable, verify that the electronic equipment is functioning properly (e.g., producing proper readouts, check active alarms).

d. Verify that the odorant is injecting into the piping system according to the desired rate.

Form GS 1670.010-1 “Odorizer Inspection Report” and Form GS 1670.010-2 “Odorizer Station Record” (see Exhibits A and B), or equivalent form(s), and/or the Company’s work management system (if applicable), shall be used to document the inspection. Form GS 1670.010-1 “Odorizer Inspection Report” is kept on file in the local systems operations department (e.g., M&R, GM&T) and Form GS 1670.010-2 “Odorizer Station Record,” is maintained on site at the odorizer station. After the last possible entry is made, the form is then kept on file in the local systems operations department.

If possible, historical electronic information should be transferred from the odorizer to an external electronic file on a periodic basis (at least every 6 months).

2.1 Individual Customer Odorizers

When gas that has not been odorized at a central facility by either the Company or a supplier is supplied to a customer(s), it may be necessary to install an individual customer odorizer if there is not sufficient natural odor to meet the regulatory requirements (refer to GS 1670.020 "Odor Level Monitoring"). Normally, individual customer odorizers are only installed where individual customers are served from non-odorized supply lines.

If the customer load requirement is 500 scfh or less, a service line odorizer as shown in Exhibit C may be used. If the customer load requirement is more than 500 scfh, the Transmission and M&R Design Team shall be consulted for design of the odorization station.

The individual customer odorizer shall be inspected at least once every three (3) calendar years. The inspection shall consist of the following items.

a. Check the odorant level, and refill or replace the tank, if necessary.

b. Visually inspect the wick (if present) for contamination.

c. Visually inspect the pitot nipple (if present) for obstructions.

Form GS 1670.010-3 "Individual Customer Odorizer Inspection" (see Exhibit D), or an equivalent form, and/or the Company's work management system (if applicable), shall be used to document the inspection.

3. ODORANT INJECTION RATE

Except for those odorizer units, such as individual customer odorizers, which rely solely on vaporization of odorant, a rule of thumb for an initial rate of injection is 0.5 to 0.8 lbs/MMCF. Odorizers used to supplement a natural odorant may have an injection rate as low as 0.1 lbs/MMCF. However, rates shall be dictated by odor levels in a system and must be adjusted on an individual basis.

4. ISOLATING AN ODORIZER

To isolate (i.e., shut in) an odorizer for any reason (e.g., maintenance, POD isolation), follow the manufacturer's instructions.

5. DEODORIZATION OF ODORANT INJECTION EQUIPMENT

All odorization equipment, including tubing and valves, removed from service should be treated with a deodorizing agent. The retired equipment shall be free of any smell having the characteristics of natural gas before it is discarded.

If deodorizing an entire system, or large equipment, consider contracting with a qualified company for deodorization and disposal.

For minor equipment replacements, the following procedure shall be used.

5.1 Deodorization Procedure for Minor Equipment Removal

a. Extreme care shall be used when disconnecting equipment or excavating in the vicinity of odorization equipment.

b. Transfer as much odorant as possible into a suitable vessel before beginning deodorization.

c. After all preparatory work is completed, add an approved deodorizing solution. Follow manufacturer's instructions.

d. When deodorizing a wick type by-pass odorizer, the wick should be removed after deodorizing. It may be necessary to deodorize the wick a second time in a separate vessel.

NOTE: An approved deodorizing solution can be used effectively to neutralize mercaptan smells in odorizer cabinets, odorizer rooms, and odorant injection pits. Periodic spraying of the above areas will effectively neutralize mercaptan odors. DO NOT use a commercial liquid bleach solution for clean up or neutralizing.

Odorant equipment that is removed with the purpose of reusing shall be sealed and stored in a proper container to confine the odor.

6. RECORDS

For distribution systems, the local systems operations department (e.g., M&R, GM&T) shall retain records for a period of 3 years, plus the current year.

For transmission lines, the local systems operations department shall retain records for a period of 5 years, plus the current year.

For odorization equipment located at LNG facilities, the local systems operations department shall retain records for a period of 5 years, plus the current year.

EXHIBIT A

ODORIZER INSPECTION REPORT

Company	Location (Name and/or Number)
Station Name and/or Location	**Odorizer Number**
Type of Odorizer (manufacturer, model no., etc.)	**Tank Capacity (gallons)**

Date Inspected				
Inspected By				
Flowrate as Found (Specify Units: mmcfh, mcfh, etc.)				
Injection Rate as Found (lbs/mmscfh)				
Injection Rate as Left (lbs/mmscfh)				
Micrometer Reading (Bypass Odorizer)				
Differential Across Bypass Odorizer				
Odorant Level Reading on Tank (Specify Units: gallons, lbs, %full)				
Note actions taken in remarks section to address the following.	Yes	No	N/A	Remarks
Leaks Found?	☐	☐	☐	
Active Alarms?	☐	☐	☐	
Filter Element Inspected?	☐	☐	☐	
Other Maintenance?	☐	☐	☐	
Additional Remarks:				

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Odorant and Odorization Equipment Inspection and Maintenance**	Standard Number: **GS 1670.010**
Supersedes: 01/01/2010		Page 6 of 8

EXHIBIT B

ODORIZER STATION INSPECTION RECORD

Company	Location Name and/or Number	Station Name and/or Location	Odorizer Number

Date	Purpose					Status		Inspector	Remarks
	RC	SI	OC	OD	Other	ON	OFF		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
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	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		
	☐	☐	☐	☐	☐	☐	☐		

RC-Routine Check **SI-Scheduled Inspection** **OC-Odor Complaint** **OD-Odorant Delivery**

Form GS 1670.010-2
(01/2010)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Odorant and Odorization Equipment Inspection and Maintenance**	Standard Number: **GS 1670.010**
Supersedes: 01/01/2010		Page 7 of 8

EXHIBIT C

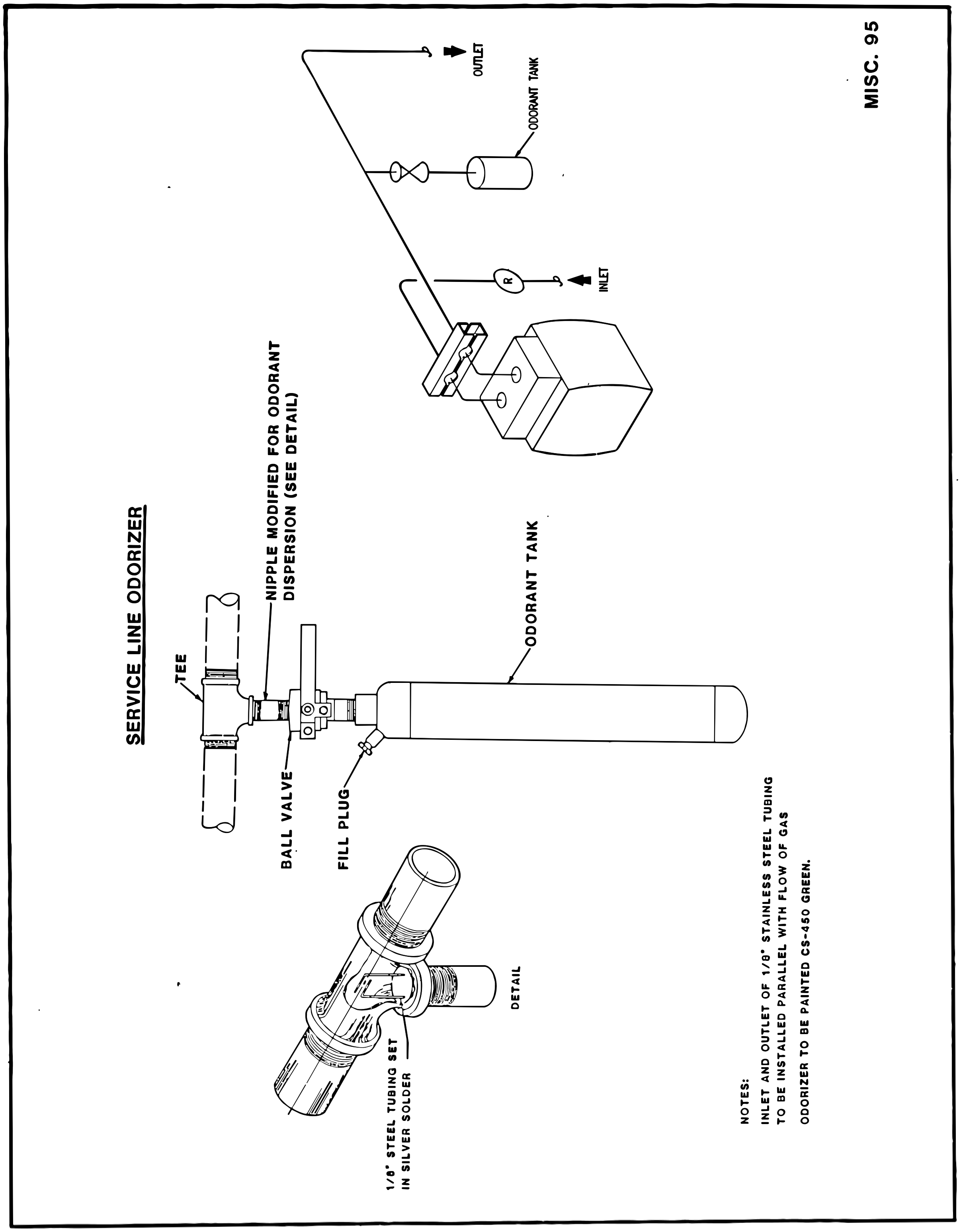

EXHIBIT D

INDIVIDUAL CUSTOMER ODORIZER INSPECTION RECORD

Company	Location Name and/or Number	Customer Name			PSID or Site ID (if applicable)
		Customer Service Address			Map Reference / GPS Coordinate
		Town or Township	County	State	

Date	Purpose				Instrument Number	Inspector/Observer	%Gas in Effluent	Remarks
	SI	OC	CI	Other				
	☐	☐	☐	☐				
	☐	☐	☐	☐				
	☐	☐	☐	☐				
	☐	☐	☐	☐				
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	☐	☐	☐	☐				
	☐	☐	☐	☐				

SI-Scheduled Inspection OC–Odor Level Monitoring Check CI-Customer Inquiry

Form GS 1670.010-3
(01/2010)

Effective Date: 01/01/2016	Odor Level Monitoring	Standard Number: **GS 1670.020(KY)**
Supersedes: 01/01/2014		Page 1 of 5

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.625; KY 807 KAR 5:006 Section 26(3)

1. GENERAL

The purpose of this procedure is to establish a program for monitoring the odor level of gas in distribution systems, including propane (LPG) distribution systems. Gas entering distribution systems shall have sufficient odor levels. The odor must be produced from natural constituents present in the gas stream or by the injection of commercial odorants.

Federal regulations also require that odorant not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight. Odorant purchased by the Company has negligible solubility in water.

Equipment used by the Company for odorization shall be such that it introduces the odorant without wide variations in the level of odorant.

2. ODORIZATION CRITERIA

2.1 Distribution Lines

Combustible gas entering a **distribution line** shall have sufficient odor levels. The intensity of the odor shall be such that this gas is readily detectable at concentrations of 1/5 the lower explosive limit (e.g., 1.0 percent natural gas in air, 0.40 percent propane gas in air).

2.2 Transmission Lines

A **transmission line** in a Class 3 or Class 4 location shall be odorized unless:

a. at least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

b. the line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:

   1. an underground storage field;
   2. a gas processing plant;
   3. a gas dehydration plant; or

4. an industrial plant using gas in a process where the presence of an odorant:
    i. makes the end product unfit for the purpose for which it is intended;
    ii. reduces the activity of a catalyst; or
    iii. reduces the percentage completion of a chemical reaction, or.

c. in the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location.

The intensity of the odorization shall be such that this gas is readily detectable at concentrations of 1/5 the lower explosive limit (e.g., 1.0 percent natural gas in air).

3. ODOR LEVEL MONITORING

The Company shall monitor the gas for the proper concentration of odorant using an instrument capable of determining the percentage of gas in air.

4. ODOR LEVEL TEST LOCATIONS AND FREQUENCY

To test the effectiveness of the odorization program, odor level tests shall be taken at locations and frequencies as follows.

Location	Frequency
Systems downstream of odorizers and systems that contain a natural odorant (e.g., local production)* • With ten (10) or fewer customers • With more than ten (10) customers	 95 days Weekly
Downstream of individual customer odorizers	95 days
Areas of extensive new or replaced piping systems	As soon as practical after in-service date and as needed until acceptable odor levels are sustained
Areas in the vicinity of: a. an accidental ignition of gas, b. a gas related incident resulting in a death or hospitalization, c. an explosion.	Promptly after incident

*Appropriate test points will be:

a. specifically selected based on system extremities and/or possible low flow areas, and/or

b. randomly selected to coincide with service calls throughout the division or area.

NOTE: A best practice is for Field Operations to meet with Engineering on an as needed basis to identify system extremities (e.g., extended growth, operational changes) and possible low flow areas to be included as test locations.

5. TESTING

For areas downstream of odorizers and non-odorized local production delivery points, it is advisable that the odor level tests within an area be taken at different times during the period described above. Customers' sense of smell may also be used to conduct and document such tests.

Odor level tests shall be performed throughout the distribution systems and can include tests at customers' premises using approved odor level detection equipment to determine the percent gas in effluent at which the odor is readily detectable.

Form GS 1670.020-1 "Odor Level Report" (see Exhibit A), or a computer generated data log provided by approved odor level detection equipment having the equivalent data, shall be used to record all odor level tests. An exception is an odor level test conducted downstream of an individual customer odorizer, which may be documented on Form GS 1670.010-3 "Individual Customer Odorizer Inspection Record" (see GS 1670.010 "Odorization Equipment Inspection and Maintenance").

The original copy of Form GS 1670.020-1 "Odor Level Report," or the computer generated data log shall be retained in each area and a duplicate copy sent to the Operations Center Manager or designee. The report shall be reviewed by the Operations Center Manager or designee for unsatisfactory odor levels.

6. NOTIFICATION REQUIREMENTS

If insufficient odor is detected in the system (e.g., a reading above 1.0% natural gas in effluent), local Field Operations leadership or Integration Center leadership, as appropriate, shall be notified immediately.

Low odor level readings (e.g., between 0.0 and 0.1% natural gas in effluent) may indicate that there is too much odorant in the gas. High odor level readings (e.g., between 0.8 and 1.0% natural gas in effluent) may indicate a possible issue. If either of these borderline situations is found, local field operations leadership or Integration Center leadership, as appropriate, shall be notified immediately.

7. REMEDIAL ACTIONS

Below is a list of appropriate steps that may be taken to investigate and remediate insufficient or borderline odor level readings. However, the list below is not meant to be all inclusive.

a. Conduct additional odor level tests.

b. Confirm odor level test equipment is operating properly.

c. Confirm technician is operating the odor level test equipment properly.

d. Verify that the technician’s olfactory senses are “normal” (i.e., technician does not have a head cold or hay fever, is not using a nasal inhaler to treat allergies, or has not just worked on an odorant injection system).

e. Verify that existing odorizer(s) are operating properly, and/or check odorizer alarm(s).

f. Adjust odorant injection rate(s).

g. Provide supplemental odorization.

h. Verify that supplier odorant and Company odorant are compatible.

Remedial actions shall be documented on Form GS 1670.020-1 “Odor Level Report” or Form GS 1670.010-3 “Individual Customer Odorizer Inspection Record”, or equivalent form, and/or the Company’s work management system (if applicable).

8. RECORDS

The date and time of the monitoring shall be recorded in the electronic WMS Job Order execution remarks field. Where a WMS Job Order does not exist, the date and time shall be documented on Form GS 1670.020-1 “Odor Level Report” or Form GS 1670.010-3 “Individual Customer Odorizer Inspection Record,” or equivalent form.

For distribution systems the local systems operations department (e.g., M&R, GM&T) or local operating area shall retain records for a period of three (3) years, plus the current year.

For transmission lines, the local systems operations department or local operating area shall retain records for a period of five (5) years, plus the current year.

For pipelines supplied by odorization equipment located at LNG facilities, the local systems operations department or local operating area shall retain records for a period of five (5) years, plus the current year.

EXHIBIT A

NiSource

ODOR LEVEL REPORT

Company			Month and Year	
Operating Center			Instrument Number	
Odor Level Detection Equipment Test Results				
Date	Employee ID	Location (e.g., address, PSID or Site ID, etc.)	Tester (If different from Employee)	% Gas in Air

Form GS 1670.020-1
(01/2016)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Odorization Remedial Action	Standard Number: GS 1670.030
Supersedes: 01/01/2010		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

All blends of natural gas odorant utilized by the Company are non-toxic when injected and mixed in the gas stream in the concentrations normally employed for odorizing.

Company personnel who handle liquid odorant or operate/maintain odorizers, even occasionally, shall be Operator Qualified (OQ) to handle odorant, deal with spills/leakage, and dispose of odorant and related materials. Personnel that discover an odorant leak, but are not Operator Qualified with respect to odorization, shall immediately contact their front line leader/supervisor to provide OQ personnel for remediation (e.g., cleanup, odor neutralization, leak repair).

Prior to and directly after odorant deliveries, odorant transfers, or troubleshooting odorizer equipment, notification should be made to the local fire department, police authorities, and appropriate local area personnel.

2. DEFINITIONS

Masking – Hides the mercaptan odor but does not remove the odor or the mercaptan.

Neutralize – to render the mercaptan odor ineffective or harmless by chemically changing the mercaptan by use of a neutralizing agent (i.e., Assassin, Odor Eater).

3. PRECAUTIONS

Plastic pipe may be damaged by contact with liquid odorant. The damage consists of swelling and softening. Therefore, never introduce liquid odorant into a plastic piping system nor use it to locate leaks.

Personnel engaged in activities involving the transfer of liquid odorant, maintenance of odorizing facilities or who may come in contact with liquid odorant or concentrated odorant vapors shall take the following safety measures.

a. Wear appropriate personal protective equipment (PPE).
b. Work in a well-ventilated environment. The volatile and flammable nature of odorant can cause hazardous or oxygen deficient atmospheres to occur in enclosed areas.

c. Avoid prolonged breathing of concentrated odorant vapors. If prolonged exposure is required (e.g. removing internals of a Peerless type odorizer) an approved air purifying type respirator shall be worn.

   NOTE: The odor of gas odorant vapor will become disagreeable before reaching a concentration level which may result in personal discomfort. Due to the inherent characteristics of the olfactory senses, exposure to the odorant's obnoxious odor may temporarily desensitize a person's sense of smell.

d. Eliminate potential ignition sources from the area.

4. ELECTRICAL GROUNDING DURING ODORANT TRANSFER

The possibility of accidental ignition resulting from the differences in electrical potential between the odorant drum or transporter and the storage vessel exists when transferring liquid odorant. This potential difference might exist due to static electricity generation during the unloading process or cathodic protection potentials.

To prevent combustion during the transfer of odorant, the preferred method is to control any discharge of electricity between the drum or transporter and the storage vessel. To this end, a grounding cable shall be utilized when transferring liquid odorant.

5. SPILLS/LEAKAGE

Precautions shall be taken to avoid spills and leaks of odorant liquids and/or concentrated vapors.

In the event of a spill or leak, the following remedial action shall be taken:

5.1 Reporting

Report any significant odorant spill near a populated area immediately to local area leadership. Notification should also be made to the local fire department, police authorities, and appropriate local area personnel. It is also important that residents of adjacent properties be notified of the situation and that corrective action is being taken.

5.2 Spill Cleanup

The following steps shall be taken if an odorant spill occurs.

a. Turn-off odorizer pump, line headers, vehicle engines, etc., which are sources of odorant vapor or ignition.

b. Shut-off gas source utilized to pressurize storage tank if spill or vapor leak is from odorizer facility.

Effective Date: 01/01/2014	Odorization Remedial Action	Standard Number: **GS 1670.030**
Supersedes: 01/01/2010		Page 3 of 3

c. Counteract spills of liquid odorant with an approved neutralizing agent. DO NOT use a commercial liquid bleach solution for clean up or neutralizing.

   If the odorant spill is on the ground, neutralize, and remove contaminated soil as appropriate. Contaminated soils may be stored in DOT approved drums prior to sampling and disposal. If the spill is on concrete, absorb the odorant in sand or chemsorb, or other absorbent material. Neutralize the concrete and absorbent material. The neutralized absorbent material may then be collected and disposed of as residual or special waste.

   Masking agents may be utilized in conjunction with neutralizers.

5.3 Odorant Vapor Leak

a. Report leak condition per Section 4.1.

b. Repair the source of an odorant vapor leak promptly.

6. STORAGE

When selecting a storage area for containers of liquid odorant keep in mind safety considerations, such as flammability and high vapor pressure, as well as the nuisance factor of the odor. The storage area should be secure and well ventilated.

7. RECORDS

For distribution systems, the local systems operations department (e.g., M&R, GM&T) shall retain records for a period of 3 years, plus the current year.

For transmission lines, the local systems operations department shall retain records for a period of 5 years, plus the current year.

For odorization equipment located at LNG facilities, the local systems operations department shall retain records for a period of 5 years, plus the current year.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Tie-Ins and Tapping Pressurized Pipelines	Standard Number: GS 1680.010
Supersedes: 01/01/2014		Page 1 of 12

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.627

1. GENERAL

Tapping and Tie-in operations are often complex. Thorough knowledge and attention to detail during planning and construction activities is required.

All tapping of pressurized pipelines shall be performed by a crew qualified in installation and use of the proper fittings, equipment, and procedures.

1.1 Material

Tapping fittings shall have a pressure rating equal to or greater than that of the pipeline. Tapping equipment shall have a pressure rating equal to or greater than the operating pressure of the pipe at the time of the tapping operation. Refer to manufacturers' documentation for the design pressure of specific fittings and tapping equipment. Use the tool recommended by the manufacturer to complete the tapping operation.

1.2 Pressure Testing

Pressure testing of tie-in fittings and/or joint shall be done in accordance with applicable GS 1500.010 "Pressure Testing."

Fittings used for tapping and plugging, such as fittings by T.D. Williamson and Mueller, as well as related bypass fittings and joints which are not subjected to the main test pressure, shall be tested prior to tapping operations.

Performing a leak test on an untapped tapping or stopping fitting can dent or collapse the pipeline it is installed on. The collapse can occur when there is a significant differential between the system pressure and the intended test pressure for the fitting. A full encirclement type fitting is more apt to cause a problem than a tee type fitting.

1.3 Safety and Related Standards

All applicable HSE safety standards shall be followed including the following.

a. HSE 4100.010 "Hazardous Atmosphere Considerations."

b. GS 1770.010 "Prevention of Accidental Ignition."

2. TIE-IN CONSIDERATIONS BY MATERIAL TYPE

2.1 Plastic

Two basic types of tie-ins are performed on plastic pipe:

a. Installation of a side wall fitting (e.g., tapping tee, branching saddle, tap fitting) onto the plastic pipe. Refer to GS 1304.010 "Electrofusion Joining."

NOTE: It is very important to only hand tighten a plastic tapping tee's cap. The use of wrenches or other tools can permanently damage the fitting.

b. Installation of plastic pipe and/or an in-line plastic tee utilizing a squeeze off tool to stop the flow of gas. Refer to GS 1680.040 "Squeeze-Off Procedures for Plastic Pipe," as well as Gas Standards Series 1300 "Pipe & Fitting Joining."

Joints should be fused except where the confines of the excavation or safety considerations dictate the use of mechanical fittings.

2.2 Steel or Wrought Iron

2.2.1 Welded Tie-in

The preferred method of tie-in to steel pipe is to stop the flow of gas using inline valves or approved line stoppers and welding directly to the end(s) of an existing pipeline or to an approved tie-in fitting.

NOTE: If wrought iron pipe is exposed at the location of the tie-in and it has not been previously identified in the work order or on maps, engineering must be contacted for additional guidance.

2.2.2 Tapping and Stopping

The maximum pressure for which tapping or stopping equipment may be used is limited by the lowest pressure rating of any one of the following:

a. The fitting connected to the pipeline, or

b. The equipment being used.

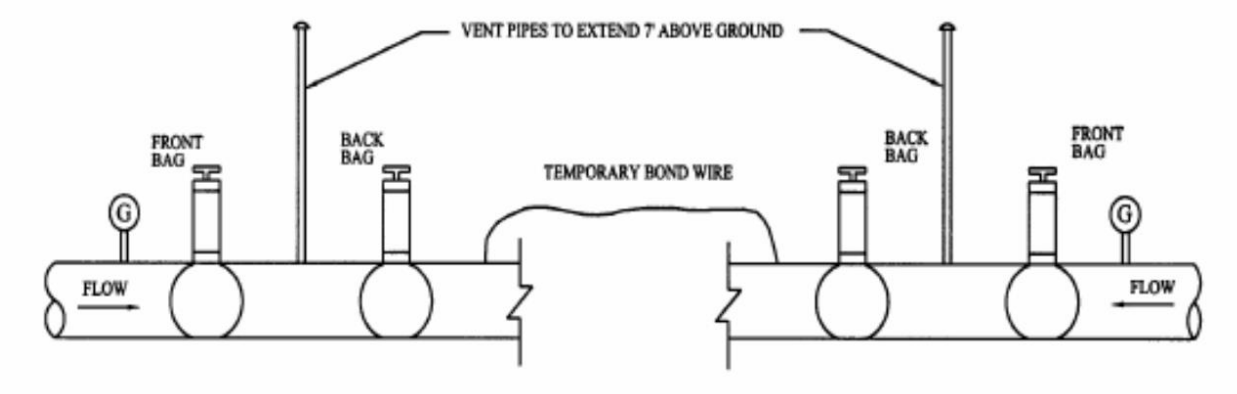
It is acceptable to temporarily lower the pipeline system operating pressure during tapping and stopping operations to a pressure lower than the maximum allowable operating pressure of the tapping and/or stopping device, providing the device does not become a permanent part of the tie-in fitting.

2.2.3 Bag and Diaphragm Type Pipeline Stoppers

The use of inflatable bags or diaphragm type stoppers is limited to low pressure for tie-ins of steel and wrought iron pipelines. Exception: inflatable bags or diaphragm type stoppers may be used on higher pressures with approval by at least one of the following: an engineer, a field operations leader/supervisor, a construction leader/supervisor, or a qualified designee, but not exceed the manufacturers' pressure limitations. Because gas may be introduced into the immediate work area when they are used, inflatable bags or diaphragm type stoppers are the least preferred line stopping method and should only be used when the availability of manpower, equipment or piping materials involved dictate their use.

Stopping equipment shall be used in accordance with the manufacturer's instructions and pressure limitations. Refer to Figure 1 for guidance when installing low pressure stoppers.

Figure 1



2.3 Cast Iron

When the term "cast iron" is used in this gas standard, it also refers to ductile iron and gray iron.

Cast iron pipe shall not be joined by threading, brazing, or welding. When steel or plastic pipe is to be joined to cast iron pipe, the joint shall be made with an insulated coupling (with the insulating side on the same side as the cast iron).

The outside diameter of the cast iron pipe shall be determined to ensure that the proper size coupling is available. To establish the pipe's dimensions, the diameter or the circumference of the pipe must be measured.

2.3.1 Joint Restraint

When joining plastic pipe to cast-iron, if a restraining fitting is not used, the joint shall be designed in a manner that will provide adequate restraint against pull-out forces and avoid transmitting forces to adjacent un-reinforced joints. This may be accomplished by the use of pipe restraints (e.g., anchor clamps, electrofusion restraints) when insertion of the plastic pipe through a casing is involved or by installing offsets in the plastic pipe adjacent to the tie-in point.

2.3.2 Stopping Gas Flow

The use of inflatable bags or diaphragm type stoppers is limited to low pressure for tie-ins of cast iron pipelines. Exception: inflatable bags or diaphragm type stoppers may be used on higher pressures with approval by at least one of the following: an engineer, a field operations leader/supervisor, a construction leader/supervisor, or a qualified designee, but not exceed the manufacturers' pressure limitations. Because gas may be introduced into the immediate work area when they are used, inflatable bags or diaphragm type stoppers are the least preferred line stopping method and should only be used when the availability of manpower, equipment or piping materials involved dictate their use. Refer to Figure 1 for guidance when installing low pressure stoppers.

NOTE: Consider using existing valves or installation of approved tie-in fittings onto cast iron pipe at alternate locations. Installation of a bypass or the shut-down of customers may have to be considered.

2.3.3 Tapping

Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:

a. Existing taps may be used for replacement service, if they are free of cracks and have good threads, and

b. a 1-1/4 inch tap may be made in a 4 inch cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6 inch or larger pipe.

"Reinforced," as used in this standard, means using a band-type fitting with a full encirclement gasket (e.g., Servi Seal).

Table 1 shows the acceptable methods for tapping a cast iron pipe.

Where a saddle is used, a tap hole is drilled (not threaded) into the cast iron or ductile iron pipe, and a tapping tee is threaded into the saddle.

To resist longitudinal cracks between taps, taps into cast iron or ductile iron pipe should be separated longitudinally by at least the circumference of the pipe being tapped.

Table 1 – Taps Made in Cast Iron or Ductile Iron Pipe

Main Size	**Tap Size**			
	1” or 1 1/4”	2”	3”	4”
2”	Reinforced	Reinforced	X	X
3”	Reinforced	Reinforced	Reinforced	X
4”	Reinforced (See Note below.)	Reinforced	Reinforced	Reinforced
6”	Direct Threading, Saddle, or Reinforced	Reinforced	Reinforced	Reinforced
8”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Reinforced	Reinforced
10”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Reinforced	Reinforced
12”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Reinforced
14”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Reinforced
16”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced
18”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced
20”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced
24”	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced	Direct Threading, Saddle, or Reinforced

NOTE: In locations where climate, soil, and service conditions would not create unusual external stresses on cast iron pipe, threaded 1 inch or 1-1/4 inch taps may be installed on 4 inch cast iron or ductile iron without reinforcement.

3. WRITTEN TIE-IN PLAN

3.1 Plan Requirements

A written plan shall be prepared for tie-in and bypassing operations on all designed capital mainline installation and replacement work.

The written tie-in plan shall prescribe that an adequate labor force, appropriate material and required tools are available; proper steps are followed; and personal, public and customer safety is ensured. The written plan shall be reviewed with the personnel responsible for performing the tasks prior to the tie-in(s).

It is permissible to develop standard written plans for tie-ins that are not complex. However, they must be specifically adapted to meet the staffing needs and requirements of each individual tie-in.

Items to be considered but not limited to for development of written plans are:

1. Necessity of, size, length and temperature limitations for a bypass,
2. safety precautions (e.g., traffic control),
3. scope or extent of system to be tied in and/or bypassed,
4. the need for reinforcement for branch connections refer to GS 2420.010 “Reinforcement Requirements for Branch Connections,”
5. verification of pressure and content,
6. pressure control and monitoring,
7. determining the sequence of closing and opening valves or any other flow controlling device,
8. planning for additional pressure monitoring for industrial or commercial customers affected by the tie-in (e.g., flow restriction due to bypass or change in flow direction),
9. planning for additional pressure monitoring at regulator stations where the tie-in significantly affects the normal flow through the station,
10. the possibility that mechanical couplings exist in the pipeline (providing support at tie-in locations; strapping, anchoring, or blocking of changes in direction or soil movement; taking the pipeline out of service or reducing the operating pressure during construction and/or tie-in operations),
11. check for leak-through of line stopping devices,
12. leak tests for tap fittings, tie-in piping, and temporary bypasses (refer to applicable GS 1500.010 "Pressure Testing" for additional guidance),
13. purge points and vent locations for both abandoned lines and lines being placed in service and temporary bypasses, (refer to GS 1690.010

"Purging"),

14. communication between critical points during the operation,
15. notification of customers who will have service temporarily interrupted (if applicable),
16. notification of local Field Operations Leaders/Supervisors, Gas Control, measurement and regulation technicians, construction leaders, as appropriate, if sections of pipeline will be temporarily taken out of service, and
17. odorant level testing if determined necessary by engineering.

3.2 Plan Accountability

Field Engineering shall prepare or provide final review of the written tie-in plan for designed capital work. It may be appropriate to request input from construction personnel for non-typical tie-in plans.

For emergency mainline installation and replacement design capital projects, a written tie-in plan is not required. Field Engineering should be consulted for assistance if the size, length, and configuration of the tie-in(s) are determined to be extensive.

The details for all tie-ins shall be discussed with the construction crew by either the field leader/supervisor or construction coordinator prior to execution to be well understood.

4. PRE-CONSTRUCTION

The following steps shall be completed in the field prior to tie-in/tapping operations.

a. Set up work area protection (e.g., traffic control, fire extinguisher).

b. Crew person in charge of project (e.g., crew leader, construction coordinator/inspector) reviews tie-in plan with personnel performing the tasks. Designate personnel responsible for various aspects of the operation. If modifications to the plan are required after review at the job site, the changes shall be approved by an engineer, a field operations leader/supervisor, a construction leader/supervisor, or a qualified designee by documenting the changes and those parties involved in determining them. Any changes or adjustments to the tie-in plan shall be communicated with the personnel performing the tasks and documented that the discussion took place.

c. Expose pipe at tie-in location(s). Verify that the exposed pipe is the one to be tapped by confirming the diameter, pressure, content, material, coating, joint connections, manufacturer's markings, color, pipe temperature, etc. A recommended best practice is to expose tie-ins early on in the project, so that differences between the plan and what actually exists in the field can be addressed in a timely manner.

NOTE: If pressure verification indicates a pressure that is above the MAOP or outside of the **normal operating pressure** ranges as defined in GS 1012.010 "Definitions," promptly notify local System Operations leadership.

d. If there is a possibility that non-restraint type mechanical couplings exist in the pipeline, the following steps should be considered to help prevent coupling pullout.

   1. Check the tie-in plan and/or contact Engineering to consider taking the pipeline out of service or reducing the operating pressure before attempting to uncover the pipeline.
   2. Install concrete support under the tie-in location to avoid additional stress on the existing coupled pipeline. Provide protection for the pipeline from damage by the concrete by installing extra coating and tape wrap, rockshield, or an equivalent protective isolating material.
   3. Install support (e.g., sandbags, sidebooms) on isolated sections of mechanically joined pipeline to avoid additional stress.
   4. Expose at least one joint back (in each direction if necessary) from the anticipated tie-in to determine whether the coupling provides positive restraint. If unable to determine, then adequate restraint must be provided. Only uncover one joint at a time and if necessary provide restraint then backfill. In the event that at least one pipe joint cannot be exposed (e.g., road crossing), the mainline shall be anchored or additional pipeline replacement should be considered. Refer to GS 1320.010 "Mechanical Coupling Connections" for additional guidance on strapping and anchoring.

e. Inspect pipe condition to determine suitability for tapping.

   1. Inspect pipeline for external corrosion. Refer to GS 1410.010 "Metallic Pipeline Exposures" for additional guidance.
   2. Verify wall thickness (if appropriate).
   3. Verify proper tap/seam/joint relationships. The tap should not intersect a longitudinal pipe seam or a circumferential weld of the pipeline. Refer to current company welding procedures for additional guidance.
   4. Check for evidence that would indicate the existence of a casing (e.g., variance in diameter or material, presence of vents).

f. Verify that tapping equipment is rated equal to or greater than the operating pressure.

g. Verify communications equipment is functioning properly.

5. DURING CONSTRUCTION

5.1 Pressure Monitoring

The most crucial part of the tie-in/bypass operation is the initial stopping or rerouting of the gas supply. To ensure that pressure is maintained, monitoring shall be conducted during the installation and operation of the stopping and/or bypassing equipment.

In the case of looped systems, gauges shall be monitored to ensure that a sufficient volume of gas is flowing through the looped system and that the flow of gas is not watered off or blocked off.

Special consideration should be given to monitoring pressures at industrial or commercial customers affected by the tie-in (e.g., flow restriction due to bypass or change in flow direction) to avoid operating issues or an unplanned service interruption.

In addition, special consideration should be given to monitoring pressures at regulator stations where the tie-in significantly affects the normal flow through the station. For example, if a tie-in involves shutting down a section of pipeline immediately downstream of a regulator station supply, bypass valve or regulator orifice, leak-through may occur which may cause a buildup of downstream pressure and a possible overpressure situation.

When the existing mains are stopped/plugged, a variance of pressure generally occurs on either side of the separation. If an unexpected sharp pressure drop is observed, it may be necessary to restore the flow of gas by either increasing the pressure at the regulator (if possible) or by removing the stopping/plugging device. At no time shall a stopping device be removed if there is any indication that an outage has occurred, until corrective action has been taken.

5.2 Bypassing and Stopping Techniques

Engineering can provide assistance for appropriate bypass sizing.

Whenever the flow of gas is stopped, the isolated section of main shall be checked for leak-through before cutting into or parting the line. When positive shut-off of gas by a valve or line stopper is not accomplished, "live-gas" precautions to avoid exposure to combustible gas-air mixtures shall be strictly followed. Refer to GS 1770.010 “Prevention of Accidental Ignition” for additional guidance. An air mover or purger may be used to prevent the introduction of gas into the work area at open ends. Refer to GS 1690.010 “Purging” for additional guidance.

Before a bypass is placed in operation, the bypass piping shall be leak tested. Refer to applicable GS 1500.010 “Pressure Testing” for additional guidance.

Regulation contained in temporary bypasses, shall be designed by engineering.

When designing an in-line tie-in along a one-way feed, the installation of a bypass is typically necessary to maintain gas service to downstream customers.

5.3 Joining Considerations

The preferred method for tie-in joints shall be welded or fused. Some exceptions include:

a. Following manufacturer's recommendations if a weld could result in weld heat or splatter deteriorating a bag, stopper, or valve,

b. a combustible atmosphere in the work area cannot be avoided,

c. other structures, unusual depth, or restrictions on excavation size may prevent adequate space for welding or fusion,

d. the tie-in is on cast iron pipe,

e. an installation is temporary (e.g., regulators for bypassing or uprating), or

f. it is not possible to make an acceptable plastic fusion due to propane permeation of plastic pipe.

5.4 Additional Tie-In Considerations

The following general tie-in considerations should be used as applicable.

a. Certain branch connections may require reinforcement, depending on size and pressure. Refer to GS 2420.010 "Reinforcement Requirements for Branch Connections" for additional guidance.

b. The height of all tie-in fittings must be considered prior to installation to ensure adequate cover. Final cover from top-of-ground to top-of-fittings involved with the tie-in should be installed according to gas standard GS 3010.090 "Cover."

c. Minimize the effects of contraction/expansion of plastic pipe on tie-ins. Whenever possible, the final tie-in should be performed after the majority of the pipeline is backfilled and allowed to remain overnight to let the pipe cool down to near normal ground temperatures.

d. In case piped situations, when there is any possibility of excessive ground settlement, the carrier pipe shall be supported by installing a split piece of rigid pipe under the tie-in connection, spanning the areas of possible settlement as illustrated below.

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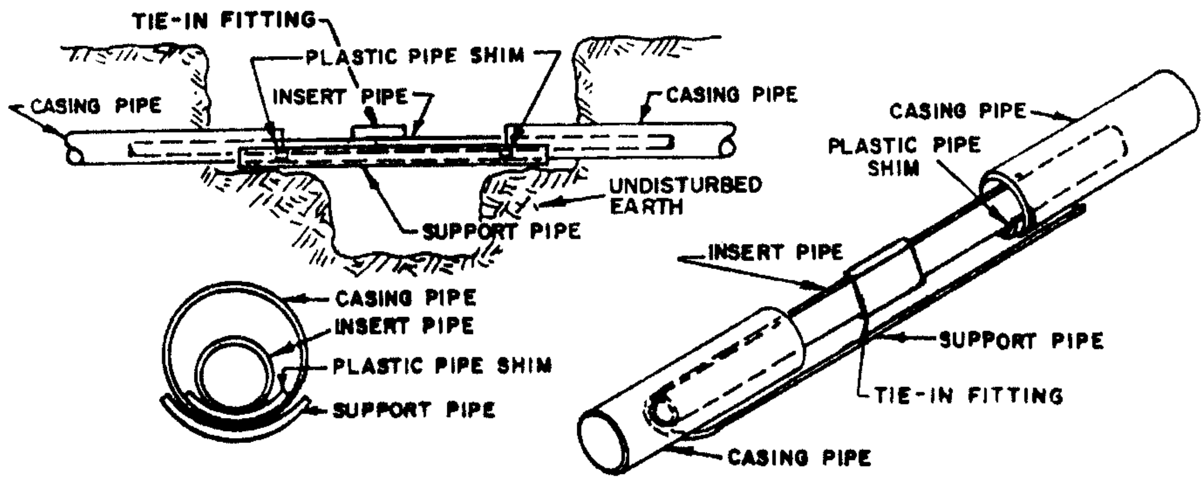

e. All tie-in fittings and tapping equipment shall be adequately supported. Larger diameter pipe may require special support (e.g., concrete pad).

f. Use backfill material that will compact well, (e.g., sand, gravel mixture (bankrun), screenings). Heavy or wet clays and frozen earth are not suitable for bedding pipe at tie-ins.

g. Weld fittings and steel pipe shall be used to make elevation changes that ensure that plastic to steel transition connections are made on firm ground. Transition fittings shall not be welded directly to a three-way tee (shortstopp or spherical tee). Additional information regarding plastic to steel transition connections is found in GS 1680.020 "Plastic to Steel Transition Connections."

h. Stick plastic pipe may be fused to coiled plastic pipe at tie-in points to facilitate the tie-ins.

6. POST-CONSTRUCTION

The following steps shall be followed after tie-in/tapping operations are completed.

a. Inspect for internal corrosion if a piece of the pipe is removed for the tie-in. Refer to GS 1440.010 "Internal Corrosion" for additional guidance. Report findings according to GS 1410.010 "Metallic Pipe Exposures."

b. Apply corrosion control materials according to GS 1420.010 "Corrosion Control Design-General" and/or Form GS 1420.010-1 "Transmittal of Corrosion Control Requirements."

c. Restore gas service to affected customers.

d. Monitor pressure gauges to ensure the piping system is operating as expected.

e. Complete each tie-in by removing tapping equipment and installing completion plug, removing squeeze off jacks or removing bags and installing leak repair clamps, etc.

f. Engineering will be responsible for determining whether post construction odorant level testing is necessary and be part of the tie-in plan. If odorant level testing is required, refer to the Company's existing procedure(s).

7. RECORDS

Approved written tie-in plans shall be filed with the work order completion report.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	**Plastic to Steel Transition Connections**	Standard Number: **GS 1680.020**
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

Plastic to steel transition connections shall be made by using approved fittings. The preferred order of material selection is:

1. weld steel-to-plastic fusion transition fitting,
2. pullout restraint type mechanical compression coupling with proper gasket and stiffener, or
3. posi-hold type coupling with proper gasket and stiffener.

2. PRECAUTIONS

Regardless of the method used to make the plastic to steel transition, the following precautions shall be taken to reduce the chance of a pullout or a bending stress failure.

a. Plastic pipe to be joined must assume ground temperature prior to making the transition connection. This may require backfilling over a major portion of the plastic line installed and if necessary, letting it remain overnight prior to making the connection. This is especially true when installing long sections of plastic pipe in extremely hot weather, since the plastic pipe will tend to contract after the trench is back-filled.

b. Permit as much slack as possible in the sections of pipe to be joined.

c. Plastic to steel transition connections shall be made in a horizontal position and supported on compacted or undisturbed ground. The pipe ends being joined shall be in axial alignment. Transition fitting shall not be welded directly to a three-way tee (e.g., shortstopp tee, Mueller tee). See Exhibit A.

d. Weld fittings shall be used when making changes in direction in order to install transition connection at pipe ditch grade or level of plastic main as indicated in Exhibit A.

e. In-line plastic pipe fittings should be installed no closer than ten (10) times the nominal pipe diameter to any steel to plastic transition fitting for sizes greater than 2-inch. For 2-inch sizes and less, in-line plastic pipe fittings should be installed no closer than 24 inches from any steel to plastic transition fitting.

NOTE: An electrofusion coupling is not considered an in-line plastic fitting.

f. Use a backfill material that will compact well, such as sand, sandy-loam soil, sand-gravel mixture (bankrun), screenings, etc. Heavy or wet clays and frozen earth are not suitable for bedding pipe at transition connections.

3. ADDITIONAL GUIDANCE FOR THE INSTALLATION OF WELD STEEL-TO-PLASTIC FUSION TRANSITION FITTINGS

The following guidelines will minimize the number of fittings needed.

a. The plastic side of the fitting should be connected by using the applicable butt fusion or electrofusion standards. Refer to GS 1304.010 “Electrofusion Joining” or GS 1302.010 “Butt Fusion Joining.”

b. The steel side of the fitting should be welded using the applicable Company welding standards. When welding, precautions shall be taken to prevent overheating the plastic side. The use of wet rags or cold water on the "bell" is helpful for this purpose. The temperatures at the bell end of the steel nipple should be such that it can be handled with bare hands.

c. If a weld steel-to-plastic fusion transition fitting needs to be shortened for tie-in purposes, the plastic end may be shortened as long as enough plastic remains for a proper butt fusion, electrofusion, or mechanical coupling installation; however, the steel end shall not be shortened for any reason.

4. ADDITIONAL GUIDANCE FOR THE INSTALLATION OF MECHANICAL COUPLINGS

Refer to GS 1320.010 “Mechanical Coupling Connections” for installation guidance.

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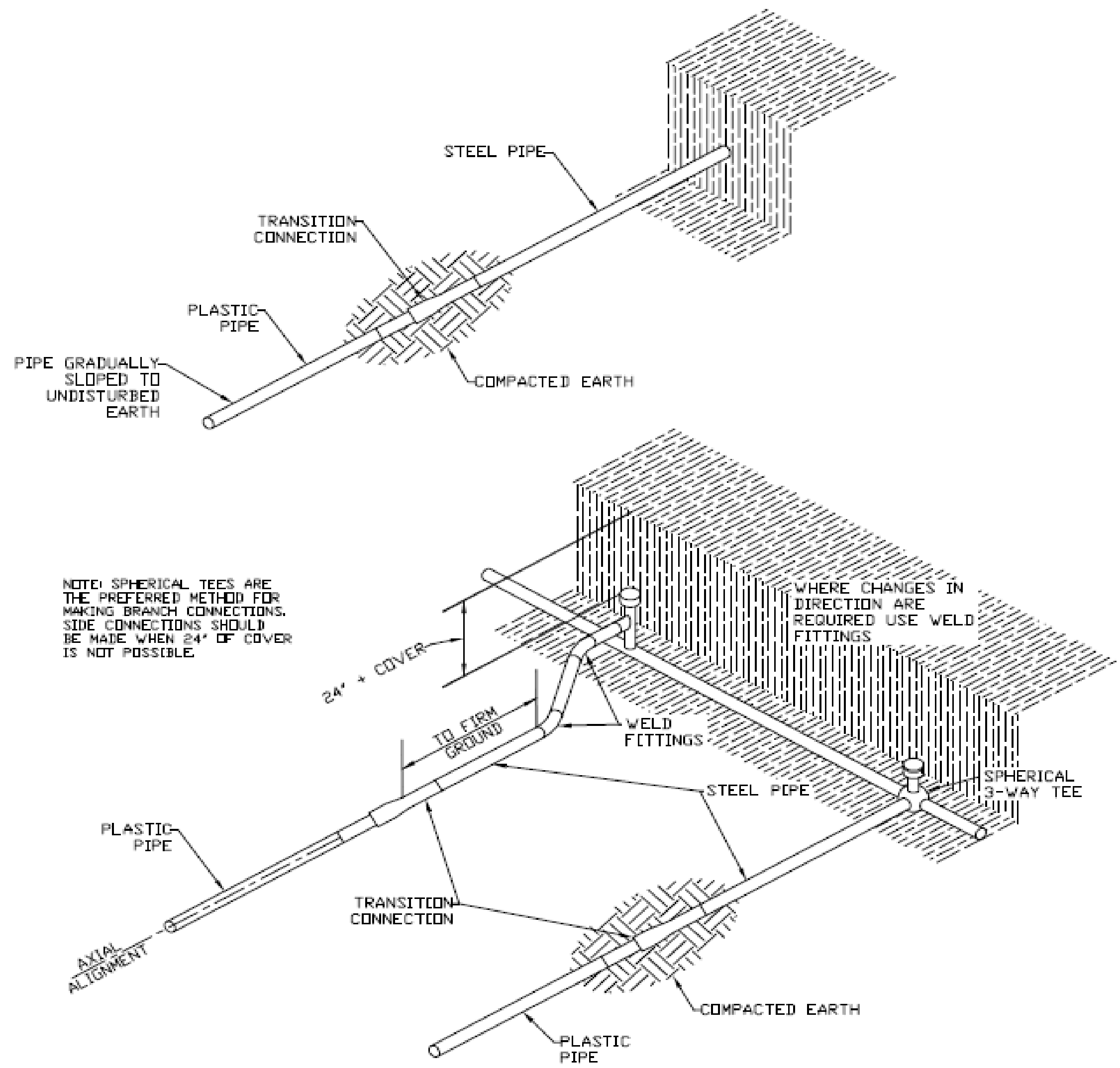
EXHIBIT A

TYPICAL TRANSITION CONNECTION INSTALLATIONS



NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Squeeze Off Procedure for Plastic Pipe**	Standard Number: **GS 1680.040**
Supersedes: 01/01/2014		Page 1 of 4

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.751

1. GENERAL

Squeeze-off units provide gas flow control by collapsing the wall of the pipe through the action of a mechanical or hydraulic squeeze-off device. The squeeze-off technique is used when the use of a valve or other stopping device is not available or is impractical.

Squeeze-off is a temporary procedure and it should not be utilized for more than eight hours. If a longer flow control time is anticipated, other techniques should be utilized.

Bubble tight flow control may not always be obtained. The squeeze-off unit should be monitored for leak-through and/or premature release during the squeeze-off period. The downstream pressure should also be monitored during that period.

2. SAFETY CONSIDERATIONS

When gas is escaping from a plastic line, the squeeze-off should be performed in a separate excavation remote from the leak.

If it is necessary to enter an excavation with blowing gas, the appropriate personal protective safety equipment shall be worn (refer to HS&E Series 4200 standards). A hydraulic squeeze-off unit with a remotely operated pump is recommended, since it will still allow the operator to squeeze-off the pipe from outside the gaseous atmosphere. If available, the use of a ground-level squeeze-off tool may limit the exposure to gas. Where practical, the separate excavation or remote pump should be located upwind from the point of escaping gas.

Static electricity control measures shall be taken as outlined in Section 3.

A fire extinguisher shall be placed upwind of a squeeze-off site.

3. STATIC ELECTRICITY CONTROL MEASURES (GROUNDING)

Prior to cutting or squeezing-off plastic pipe, action shall be taken to remove and/or prevent the buildup of static electrical charges on the plastic pipe. Plastic pipe shall be wrapped with wet soapy burlap or cotton rags or other approved static reducing material contacting the earth on each side of the squeeze-off tool, or an approved aerosol anti-static spray applied to the plastic pipeline (as directed by the manufacturer's instructions), to prevent the build-up of static electricity. This should be done at the squeeze-off point prior to the squeeze operation and subsequently at any bell hole where gas was or will be released. This should eliminate a potential source for accidental ignition and/or electrical discharge.

If an aerosol anti-static spray is used, there will not be any wet materials coming in contact with the ground.

Removal of an existing static charge on the outside pipe surface can be accomplished by the following steps.

1. Spray the pipe surface and the surrounding ground with a water/liquid detergent solution or approved anti-static spray, or wipe the pipe surface with a wet soapy cotton or burlap cloth.

2. Starting where the pipe leaves the earth, spiral wrap the wetted material around the piping at least three or four turns on each side of the work area, but outside of the tie-in and/or cut-out site. Make sure that the wet material is in contact with, or pinned to, the ground.

3. Further build-up of an outside surface static charge may be prevented by keeping the cloth wet with a soapy solution or applying an anti-static film on the pipe surface and keeping the pipe in contact with the ground.

4. GROUNDING OF TOOLS

Cutting and squeeze-off tools shall be grounded by attaching a wire from the tool to a metallic device driven into the ground. This is done to provide a ground path for any charge on the inside or outside of the pipe which might jump to the tool. A minimum #12 AWG wire is recommended for this purpose. If a ground-level tool is used, attach a ground wire to a metal stake in the soil.

5. SQUEEZE OFF AND CUTTING OF PLASTIC PIPE

Follow the manufacturer's instructions for the safe operation of squeeze-off tools including the following general guidance.

a. Make sure that the bars of the squeeze-off tool are clean and smooth.

b. Verify that the squeeze-off tool is adequately sized for the job.

c. Ensure that the over-squeeze protection (i.e., stops) is appropriate for the size and wall thickness/SDR of the pipe.

d. Install reinforcing clamps on manually operated tools when applicable.

e. Locate the squeeze-off tool or machine a minimum of three (3) times the pipe diameter or 12 inches, whichever is greater, from a socket, butt, saddle fusion, electrofusion fitting, previous squeeze point, or mechanical fitting. The distance may need to be increased if work is to be performed on the pipe (e.g., scraping the pipe for electrofusion fitting installation) between the squeeze-off location and an existing socket, butt, or saddle fusion; an electrofusion fitting; a previous squeeze-off; or a mechanical fitting.

f. Center pipe in the squeeze-off unit to obtain maximum flow control and prevent damage to pipe and squeeze-off unit.

g. The pipe should be squeezed-off at a slow rate, around two inches per minute (ipm). **For example, it should take no less than 2.25 minutes to fully compress 4 inch IPS pipe. (4.5inch/2ipm)**

h. Pipe should be squeezed just until the flow of gas has been controlled.

i. Cold weather increases the pipe's susceptibility to damage. Squeeze and release times should increase in cold weather.

j. Engage safety stops on hydraulically operated tools as a back up to maintain the squeeze-off should the tool fail to hold.

k. Before cutting or parting a pressurized pipe, check downstream of the squeeze point to verify gas flow has been controlled. If leak-through cannot be eliminated, a second squeeze-off tool can be installed or a vent equipped with an air mover/purger can be used. Refer to GS 1690.010 "Purging" for additional guidance."

6. REMOVAL OF SQUEEZE-OFF UNIT AND REROUNDING OF PLASTIC PIPE

Where flow of gas is controlled by a squeeze-off unit, a sudden release of mechanical or hydraulic pressure should be avoided. Screw clamps are more easily controlled, whereas, with hydraulic units the control of the bleed valve is essential to prevent sudden and complete hydraulic pressure loss. Controlled release of the squeeze-off force is necessary in the event that gas flow control must be rapidly reestablished.

When removing the squeeze-off tool release the squeeze very slowly around one half inch per minute. For example, it should take no less than 9 minutes to fully release 4 inch IPS pipe (4.5inch/0.5ipm).

Hydraulic units require that pressure be reapplied to remove the pressure on the wedges. After extracting the wedges, retraction can be controlled by the slow release of pressure by the bleed-off valve.

Re-rounding of the pipe is not normally required. If the pipe resumes its near normal shape (i.e., width to height ratio is approximately 2:1 or less), then flow capacity will not be reduced. When appropriate, re-rounding of plastic pipe can be accomplished by rotating the squeeze-off unit 90°, however, do not squeeze beyond the original outside diameter of the pipe. Where it is impractical, due to trench width, band clamps can be worked progressively towards the flattened point to effect re-rounding.

7. REMOVAL OF DAMAGED PIPE

Plastic pipe that has experienced deformation due to cold flow and/or permanent damage as a result of squeeze-off shall be repaired by cutting out the affected section of pipe.

8. MARKING OF SQUEEZE OFF AREA

The point of squeeze-off shall be clearly marked with durable tape or an approved marking device.

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Squeeze Off Guidelines for Steel Pipe**	Standard Number: **GS 1680.050**
Supersedes: 03/01/2010		Page 1 of 2

Companies Affected:

☑ NIPSCO Effective: 09/01/2012	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE None

1. GENERAL

Steel pipe squeeze-off shall only be used as a temporary measure to alleviate hazardous conditions during an emergency when valves or conventional stopping equipment are not viable options. Only squeeze-off tools specifically designed to squeeze-off steel pipe shall be used. When using a steel squeeze-off unit be sure to follow the manufacturer's instructions.

2. SAFETY CONSIDERATIONS

The squeeze-off should be performed in a separate excavation remote from the leak or from above ground. If it is necessary to enter an excavation with blowing gas, the employee shall wear the appropriate personal protective safety equipment (refer to HS&E standards). The use of a ground-level squeeze-off tool may completely eliminate exposure to gas. If a ground-level tool is not available, a hydraulic squeeze-off unit with a remotely operated pump is recommended, since it will still allow the operator to squeeze-off the pipe from outside the gaseous atmosphere. Where practical, the separate excavation or remote pump should be located upwind from the point of escaping gas.

Before any steel squeeze-off operation is to begin, field operations personnel shall take precautions to reduce potential hazards caused by natural gas venting into the atmosphere. Refer to GS 1770.010 "Prevention of Accidental Ignition" for additional guidance.

Ground the squeeze-off tool with a ground wire unless there is already continuity between the pipe and the ground.

A fire extinguisher shall be placed upwind of a squeeze-off site.

Contact local corrosion personnel to determine whether pipe is protected by a rectifier to prevent electrical shock.

3. ADDITIONAL GUIDELINES

It is possible for steel pipe to split when squeezing-off if the longitudinal seam is located 90° circumferentially from the tool jaws. Splitting might be prevented by positioning the tool such that the longitudinal seam is directly at the upper or lower jaw of the tool. If the pipe splits, remove the tool, rotate it 90° and squeeze-off upstream at a minimum distance of five (5) pipe diameters from the end of the split.

Complete shut-off of gas flow will not likely occur as with plastic pipe squeeze-off tools, therefore, a permanent shut-off should be made using other techniques before making permanent repairs. Unlike plastic pipe that has been squeezed-off, the squeeze-off point on steel pipe is permanently damaged. Steel pipe that has been squeezed-off shall be cut out and replaced.

NiSource

Gas Standard

Distribution Operations

Effective Date: 11/11/2014	**Purging**	Standard Number: **GS 1690.010**
Supersedes: 05/01/2014		Page 1 of 18

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.629

1. GENERAL

This standard provides guidance for purging transmission lines, distribution mains, services, and regulator stations. All facilities installed on design capital work orders shall be purged according to an approved written plan provided by Engineering. Personnel responding to a situation where pressure loss is suspected should consult with local supervision and Engineering to determine if the system is one-way or a multi-feed system.

This standard is not to be used to de-water pipelines or systems after hydrostatic testing, or remove dirt, scale, or other debris from pipelines. Additionally this standard is not to be used for purging at a propane/air plant or a LPG distribution system.

It is the responsibility of Engineering to provide a purging plan for newly constructed or abandoned pipelines.

It is the responsibility of the field leader/supervisor to ensure all personnel performing purging operations are qualified.

1.1 When Purging Is Necessary

Prior to placing a newly constructed main, service line, temporary bypass, or regulator station into service, it shall be purged with natural gas to remove pockets of air and/or a hazardous mix of gas and air to prevent customer equipment outages.

If the pressure in an existing system drops below a pressure adequate to maintain service to customers, an investigation shall be performed to determine if air has entered the system. If air has entered the system, all affected piping shall be purged to ensure 95% or more gas concentration is obtained and sustained before customer light-ups can occur. All impacted accounts shall be verified secured at either the curb valve or meter valve.

Mains and services being abandoned shall be purged with air or inert gas to remove natural gas and/or a hazardous mixture of gas and air which could cause false leakage readings.

1.2 Minimizing the Need for Purging and Customer Relights

1.2.1 New Construction or Service

When newly installed main is to be connected to a one way feed system, an evaluation should be done to determine whether to shut down the existing main and customers, build a bypass, or use a hot tap fitting. The new main must be purged regardless of the method chosen for tie-in. Exhibit A shows an example of how to minimize purging during a new main tie-in.

1.2.2 Existing Facilities

Consideration shall be given to customer load, ambient temperature and frequency of pressure monitoring to determine if repairs are necessary on damaged pipe.

If repairs are determined to be unnecessary on a damaged pipeline, then monitor the pressures in the system at the source as well as the far ends of the system and/or low pressure points of the system. If pressure is maintained above the minimum required to serve customers, then purging is unnecessary.

If repairs are determined to be necessary on a damaged pipeline then,

a. Determine if the system is a one way feed or two way feed system.

b. Install a temporary bypass to maintain pressure to downstream customers. To maintain pressure to downstream customers, it may be necessary to install and/or operate a valve, install a squeeze-off tool, stopping device, etc. If this option is performed, consideration shall be given to customer load, ambient temperature and frequency of pressure monitoring.

c. On a two way system feed determine if supply from the undamaged feed is adequate to supply the customer load. It may be necessary to operate a valve, install a squeeze-off tool, stopping device, etc. to separate the damaged section of pipe from the customers on a two way feed system.

d. It may also be necessary to purge the system from the undamaged supply point to the separation point and all services in between.

1.3 Odorant Level Testing

Engineering will be responsible for determining whether post construction odorant level testing is necessary. If odorant level testing is required, refer to the GS 1670 series of gas standards for guidance.

2. SAFETY AND NOTIFICATION

2.1 Safety

Before any purging operation is to begin, field operations personnel shall take precautions to reduce potential hazards caused by releasing natural gas into the atmosphere. Refer to GS 1770.010 “Prevention of Accidental Ignition” for additional guidance.

The following safety precautions shall be followed.

a. Place a fire extinguisher upwind at each activated vent point.

b. Smoking and open flames are prohibited.

c. Turn off all vehicles and equipment in the area where gas is being vented.

d. Plastic pipe shall not be used as vent piping.

e. Ground all purge piping with a ground wire unless there is already continuity between the vent pipe and the ground. Examples of grounding purge piping are a metallic vent pipe that is attached to a bare steel main or using a metallic purge stand that has a sharp pin at the bottom which is driven into the ground.

f. When venting gas consider overhead utility lines, building ventilator systems, house soffits or overhangs, or other areas where gas accumulation may create a hazard.

g. Vent piping shall extend seven (7) feet or more above ground level. Exhibit B shows an example of a portable purge stand.

h. Care shall be taken to avoid injuries to employees, the public and damage to property.

i. Appropriate personal protective equipment shall be worn during purging operations.

2.2 Notification

Before any purging operation begins that will involve large amounts of combustible gas being vented into the atmosphere, notification shall be made to the call center, logistics/integration/work management center, the state communication and community relations team. Consideration should be given to notify customers in close proximity and to local authorities.

3. PURGING PLAN

On all design capital pipeline work orders, purging operations shall be conducted according to the written plan and be an integral part of the approved tie-in and bypass plan. A written purge plan for dig-ins and damages is not required but shall be discussed and planned by the repair crew and/or the field leader/supervisor. If the size, length and configuration of the system are determined to be extensive, an engineer shall be contacted to assist with the development of the purging plan. Consideration should be given to the following for the development of the plan, but not limited to:

a. size, length and configuration of the pipe,

b. source(s) of purging medium,

c. number and placement of vent points needed,

d. placement of pressure gauge(s) if needed,

e. order of purging when more than one vent point is involved,

f. preparation of a sketch showing the injection point(s) and each vent point,

g. monitoring of system on upstream side of injection point(s),

h. using a service line as a vent point to avoid unnecessary excavation, and

i. having a designated contact person for communicating during the purging operation.

3.1 Pressure Control

A pressure gauge can be installed upstream of the system supplying the natural gas to assure adequate pressure is maintained to supply the customers. Depending on the time of year and the supply requirements of a customer(s) on the supply system, regulation personnel may be required to monitor pressure at regulator station(s) during the purging operation.

If engineering requires that a pressure gauge be installed and monitored as part of the written purging plan, field personnel shall install and monitor the gauge during purging operations.

4. PURGING INTO SERVICE

Purging into gas service is the act of replacing the air or inert gas in the pipeline with natural gas. When purging into gas service, the gas is released into the system at one point and vented through vent stands at one or more planned locations.

When purging mains, service lines can be utilized as vent locations; however, the use of an approved, grounded vent stand is still required. If the system being purged is looped, additional consideration must be given to assure all the air is purged from the system. Exhibit C illustrates a method of purging a newly installed system into service. Exhibit D illustrates a method of purging a system into service after a dig-in/damage has been repaired.

4.1 Prior to Purging

4.1.1 Purge Plan Communications

It is the responsibility of the crew leader and/or field leader/supervisor, to communicate each step of the purge plan to all personnel involved in the purging operation.

4.1.2 Venting

Vent points shall be provided at or near all dead ends of the system. A customer service line can be used if relatively close to the dead end. If a customer service line is used for purging mains, a vent stack shall be used and gas purge to a location to prevent migration into the residence.

4.1.3 Preventing Static Electricity

Whenever a squeeze-off tool is used to re-introduce gas into a system, it shall be grounded. Additionally, the plastic pipe shall be wrapped with wet soapy burlap or cotton rags or other approved static reducing material contacting the earth on each side of the squeeze-off tool, or an approved aerosol anti-static spray applied to the plastic pipeline (as directed by the manufacturer's instructions), to prevent the build-up of static electricity.

Take precautions to eliminate static electricity when disconnecting vent stands from plastic pipe.

4.2 Purging

4.2.1 One Vent Point

With a fire extinguisher upwind of the grounded vent stand, slowly open the vent stand valve to create a rapid and continuous flow that does not cause problems to the system upstream of the injection point. If an upstream gauge is installed, be sure it is monitored.

Using a calibrated combustible gas indicator (CGI), begin taking samples at the exit point of the purge stand. The amount of time to purge a system into service is dependent on the pipe size, length, and configuration. Purging shall continue until a CGI reading of 95% or more gas is obtained and sustained.

Remove piping associated with the purge stand in a manner that does not allow re-entry of air into the system.

Purging of newly installed service lines or existing service lines turned off at the curb valve, if applicable, is normally not a major operation, and can be performed at the meter setting; however, the following should be considered:

a. control the venting of the purge, and

b. be aware of possible sources of ignition.

4.2.2 Two or More Vent Points

Before each grounded vent stand is activated, a fire extinguisher must be placed upwind of its location. Slowly open the vent stand valve to create a rapid and continuous flow that does not cause problems to the system upstream of the injection point. If an upstream gauge is installed, be sure it is monitored.

Using a calibrated CGI, begin taking samples at the exit point of the purge stand. The amount of time to purge a system into service is dependent on the size of pipe, length, and configuration of the piping involved. Purging shall continue until a CGI reading of 95% or more gas is obtained and sustained.

Once the desired reading is accomplished, the purging operation shall continue with the opening of the next vent point before closing the current one. This process shall continue until all planned vent points have been purged.

Remove piping associated with the purge stand in a manner that does not allow re-entry of air into the system.

Purging of newly installed service lines or existing service lines turned off at the curb valve, if applicable, is normally not a major operation, and can be performed at the service meter setting; however, the following should be considered:

a. control the venting of the purge, and

b. be aware of possible sources of ignition.

5. PURGING USING THE INERT GAS SLUG METHOD

Formation of a hazardous mixture of natural gas and air during purging can be minimized by using an inert gas slug to separate the gas and air. Inert gas must be injected into the pipe through a downstream fitting as close to the source of the purge gas as possible. Begin natural gas or air flow as soon as possible after the inert gas slug has been put into the line. Do not allow more than three minutes between introduction of the inert gas slug and introduction of natural gas or air. A delay of more than three minutes will destroy the inert gas slug. Continue flow during the purge without interruption until readings of 95% or greater are obtained and sustained with a CGI at the planned vent point(s). Exhibit E shows a typical nitrogen purge manifold.

Table 1 provides information required to purge various main sizes and lengths by the slug method using nitrogen. Use a 2-inch grounded vent stand that extends seven (7) feet or more above ground level. If a poly-pig is inserted between the inert gas and the gas admitted behind, the volume of the inert gas slug can be reduced to one-half the amount shown in Table 1.

Table 1

Nominal Pipe Size (in inches)	Injection Rate (in cfm)	Cubic Feet of Nitrogen for an Inert Slug						
		500 ft.	1000 ft.	2000 ft.	5000 ft.	10000 ft.	20000 ft.	50000 ft.
4	11	19	23	29	40	53	71	107
6	29	46	56	70	98	129	173	261

8	56	77	94	117	164	217	291	439
10	96	121	147	184	257	340	457	688
12	149	173	211	263	368	486	653	985
16	273	280	342	430	605	802	1080	1632
18	367	360	440	553	777	1030	1387	2097
20	489	448	548	689	968	1283	1723	2611
22	615	541	661	831	1168	1548	2085	3151
26	930	757	925	1162	1633	2165	2916	4406
30	1331	1007	1230	1546	2173	2880	3880	5863
34	1821	1400	1733	2204	3137	4189	5677	8630
36	2117	1576	1951	2480	3531	4716	6391	9714

Notes:

1. For lengths greater than 50,000 feet consult local Field Engineering.
2. To prevent freezing, do not withdraw more than 50 cfm from a nitrogen cylinder. One nitrogen cylinder at 2200 psig contains 200 cubic feet of nitrogen at atmospheric pressure. Whenever an injection rate of more than 50 cfm is needed, more than one tank needs to be opened at once.

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6. PURGING LARGE DIAMETER MAINS AND SERVICES USING THE COMPLETE FILL METHOD

For mains and services four (4) inches through twelve (12) inches in diameter and less than 500 feet long, completely fill the pipe with an inert gas. A volume of 10% to 50% more inert gas than the total volume of the line will ensure complete filling. The volume of inert gas to use per linear foot of pipe depends on diameter (see Table 2).

For the complete fill method, use a 2-inch vent line and a riser extending at least seven (7) feet above ground level to ensure adequate velocities at the vent outlet. Continue the purge without interruption until tests with a combustible gas indicator (CGI) reach the 95% -100% range when purging the line into gas service or when the CGI reaches 0% when purging the line out of gas service.

Table 2

Complete Fill Method (for lengths less than 500 feet)		
Nominal Pipe Size (inches)	Minimum Injection Rate (in cfm)	Number of Nitrogen Tanks
4	15	1
6	20	1
8	40	2
10	60	3
12	80	3

Note: To prevent freezing, do not withdraw more than 50 cfm from a nitrogen cylinder. One nitrogen cylinder at 2200 psig contains 200 cubic feet of nitrogen at atmospheric pressure. Whenever an injection rate of more than 50 cfm is needed, more than one tank needs to be opened at once.

7. PURGING OUT OF SERVICE/ABANDONMENT

Purging out of gas service is the act of replacing the natural gas in the pipeline with air or inert gas. When purging out of gas service, the air or inert gas is released into the system at one point and vented through vent stands at one or more planned locations. A calibrated CGI shall be used to determine when a pipeline is purged. The pipeline is considered to be purged once a CGI reading of 0% gas is obtained.

Abandoning a section of pipeline is the result of the pipeline being replaced or the pipeline is no longer needed in order to serve customers.

When purging mains, service lines that are being abandoned can be utilized as vent locations; however, the use of an approved, grounded vent stand is still required. If the system being purged is looped, additional consideration shall be given to assure all the gas is purged from the system.

Natural venting is normally sufficient to purge a service line which is being abandoned. However, if it is determined that natural venting of the service line is not sufficient, air or inert gas shall be introduced to purge the service line.

7.1 Purging

It is the responsibility of the crew leader and/or field leader/supervisor, to communicate each step of the purge plan to all personnel involved in the purging operation.

Once the pipe section to be abandoned has been isolated and the pressure has been removed as part of a tie-in and bypass plan, it now can be safely purged.

Purging residual gas from a pipeline can be accomplished by the use of compressed air, inert gas or by an air mover.

When purging with compressed air, the compressor is normally connected at one location and the grounded vent stand(s) are opened to force out any residual gas. The pipeline is considered to be purged once a CGI reading of 0% gas is obtained at the vent stand(s). Once purging is complete all ends of the abandoned pipe must be sealed.

When purging with an air mover, the air mover is normally connected at one location on a grounded vent stand and the remaining end(s) are opened to allow the air mover to pull residual gas from the pipeline. In some cases, more than one air mover may be used to purge residual gas from a pipe system. The pipeline is considered to be purged once a CGI reading of 0% gas is obtained. Remove the air mover(s) from the abandoned pipe and seal all pipe ends. Exhibit F shows an example of using air movers to purge residual gas from a pipeline.

Note: When purging by use of an air mover, it is still required for the outlet to be grounded, metallic and seven (7) feet or more above the ground level.

8. FLARING GAS

Flaring of gas shall not be performed inside a regulator or meter structure or an occupied bell hole or work area. Gas must first be directed out of the regulator or meter structure, bell hole or work area before flaring shall be performed. If gas is flared, it shall only be done through a grounded metallic vent stand or pipe extending seven (7) feet or more above ground level, in a safe open area. Flaring gas shall be performed in a safe location away from overhead electric lines, tree limbs and any combustible materials. Local authorities and residents shall be notified in advance of any flaring activity.

8.1 Personnel Protection Equipment

Personnel shall wear fire resistant coveralls including hood and fire resistance gloves when operating a flare.

A fire extinguisher shall be readily available up wind of the flare.

8.2 Flaring Equipment

All flare piping shall have a minimum design pressure meeting the MAOP of the system being purged. If hoses are used to direct the gas to a flare, the hoses shall be rated to 2000 PSIG. All valves and fittings shall be rated for gas service and meet or exceed the MAOP of the line being purged. Use a soft-setting thread sealing compound on threaded connections. The gas flow control valve should be a quarter turn ball valve. Using appropriate wrenches assemble the supply line and all fittings and valves.

8.3 Flaring Procedures

Before starting the flaring operations a final safety check shall be performed to ensure the following.

a. Personnel are wearing the appropriate personnel protection equipment.
b. A fire extinguisher is located upwind of the flare location.
c. The flare is located in a safe location away from buildings, tree limbs, overhead wires and combustible materials.
d. The flare is at least seven (7) feet above ground level and is pointed no less than 45 degrees in the upwards direction.
e. The flow control valve is closed.

8.3.1 Lighting procedure

1. Check all exposed piping for leakage prior to lighting the flare. Take CGI readings along the exposed piping being used for flaring operations from the purge point connection to the top of the flare.

Verify 0% natural gas readings prior to lighting the flare.

2. An ignition source shall be present near the top or opening of the flare before the flow control valve is opened.
3. Once the ignition source is present, the flow control valve shall be opened slowly until the gas from the flare ignites.
4. The ignition source can then be removed from the flare.
5. Control the size of the flare by opening or closing the flow control valve slowly and in small increments until the desired flame size is reached.

Remember the size of the flare flame will determine how noticeable the flare is and the interest generated by the public.

At no time shall a flare be left unattended. Attended means having personnel assigned to monitor the flare. Personnel shall be trained to operate a fire extinguisher. Monitoring the flare shall be their only responsibility during the flaring operation.

8.4 Flaring completion

a. When flaring is completed and gas is no longer in the line, the flare equipment can be removed.Remove flare piping.
b. Remove the flow control valve if possible.
c. Cap, plug or blind plate the remaining blow-off valves including the flow control valve if left on the pipeline. This may be skipped if an opening to allow gas to escape is desired such as when maintaining the line, tapping or tie-ins.

9. RECORDS

Purging plans are part of the overall tie-in and bypass plan for planned installation and abandonment projects. Therefore, when a company representative signs a tie-in and bypass plan, the signature serves as record that purging was completed according to this standard.

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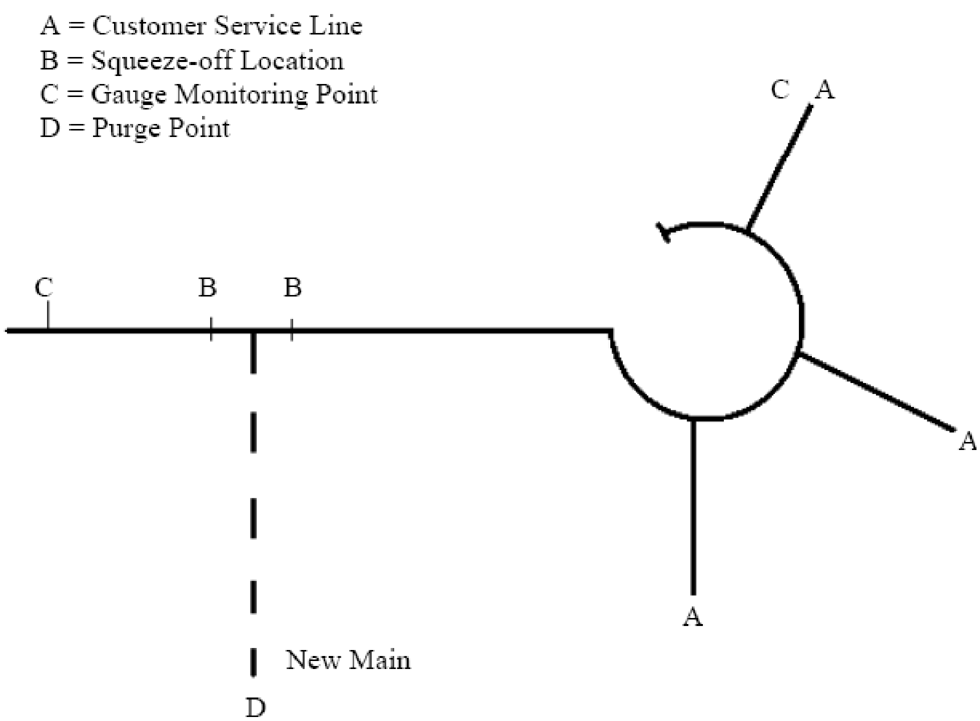
EXHIBIT A

Example of Minimizing the Need to Purge



Depending on the time of year and customer usage, squeeze-off units could be installed on a one-way feed system as illustrated above and with downstream service lines turned off at the meter, line pack should be maintained.

EXHIBIT B

Example: Portable Purge Stand

NOTE: Must be constructed using all metallic fittings.

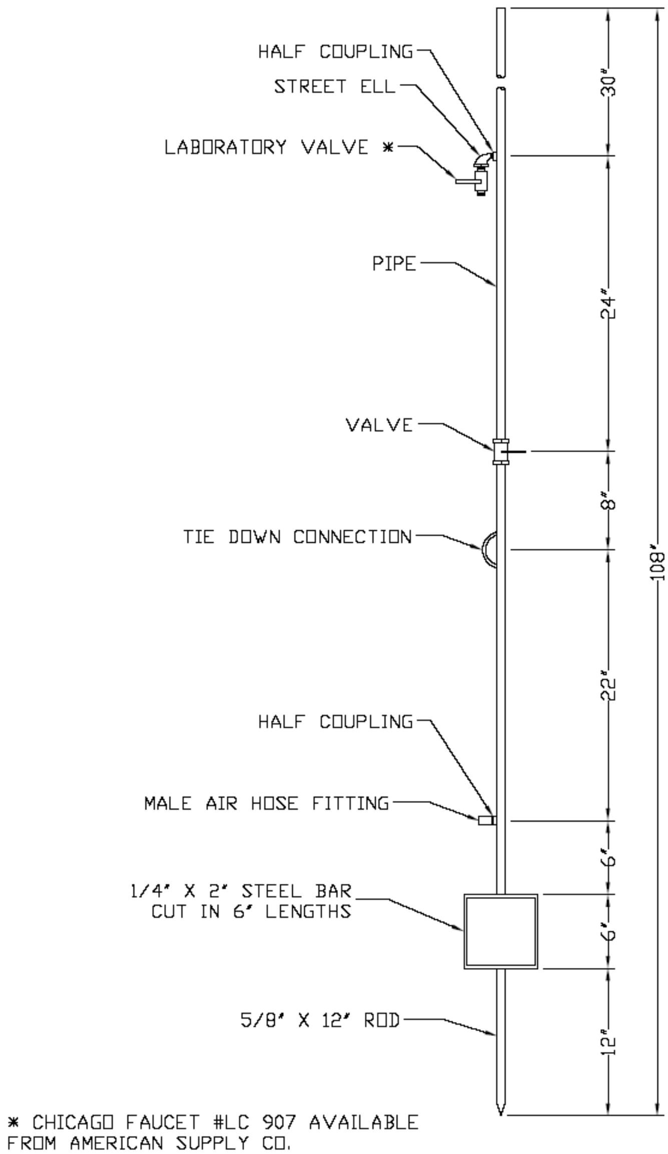


EXHIBIT C

Method of Purging Air from a New Distribution Piping System

(1) Close off 2" lines at B and C, isolate by squeeze-off, or valve if available.

(2) Open vent at 1.

(3) Open valve A.

(4) Open vent 2 when vent 1 is venting 95% or more natural gas.

(5) Close vent 1 after vent 2 is open.

(6) Open vent 3 when vent 2 is venting 95% or more natural gas.

(7) Close vent 2 after vent 3 is open.

(8) Open vent 4 when vent 3 is venting 95% or more natural gas.

(9) Close vent 3 after vent 4 is open.

(10) Close vent 4 when it is venting 95% or more natural gas.

(11) Open isolation points B and C.

(12) Purge all service lines that have been installed.

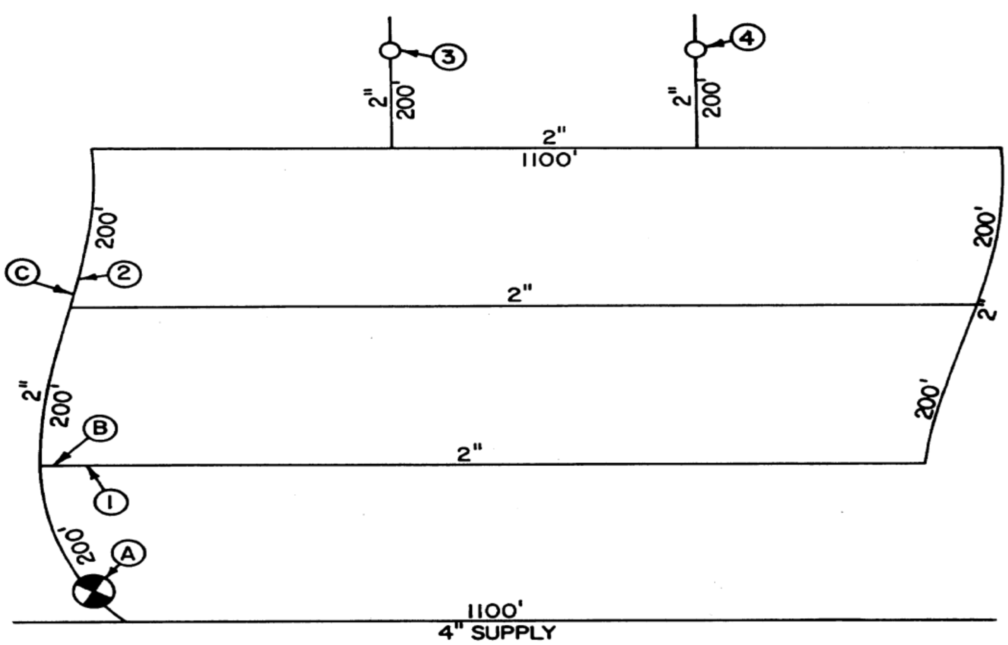


EXHIBIT D

Method of Purging Air from an Existing Distribution Piping System

(1) Close off 2" lines at B and C, isolate by squeeze-off or valve if available.

(2) Open vent at 1.

(3) Open valve A.

(4) Open vent 2 when vent 1 is venting 95% or more natural gas.

(5) Close vent 1 after vent 2 is open.

(6) Open vent 3 when vent 2 is venting 95% or more natural gas.

(7) Close vent 2 after vent 3 is open.

(8) Open vent 4 when vent 3 is venting 95% or more natural gas.

(9) Close vent 3 after vent 4 is open.

(10) Close vent 4 when it is venting 95% or more natural gas.

(11) Open isolation points B and C.

(12) Purge all services lines installed.

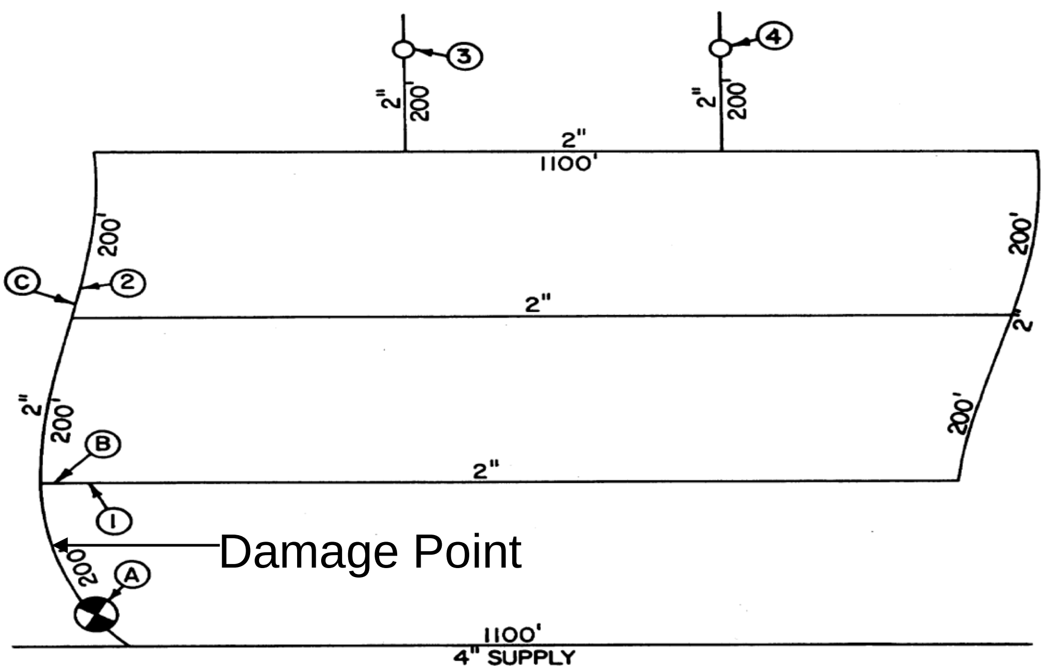
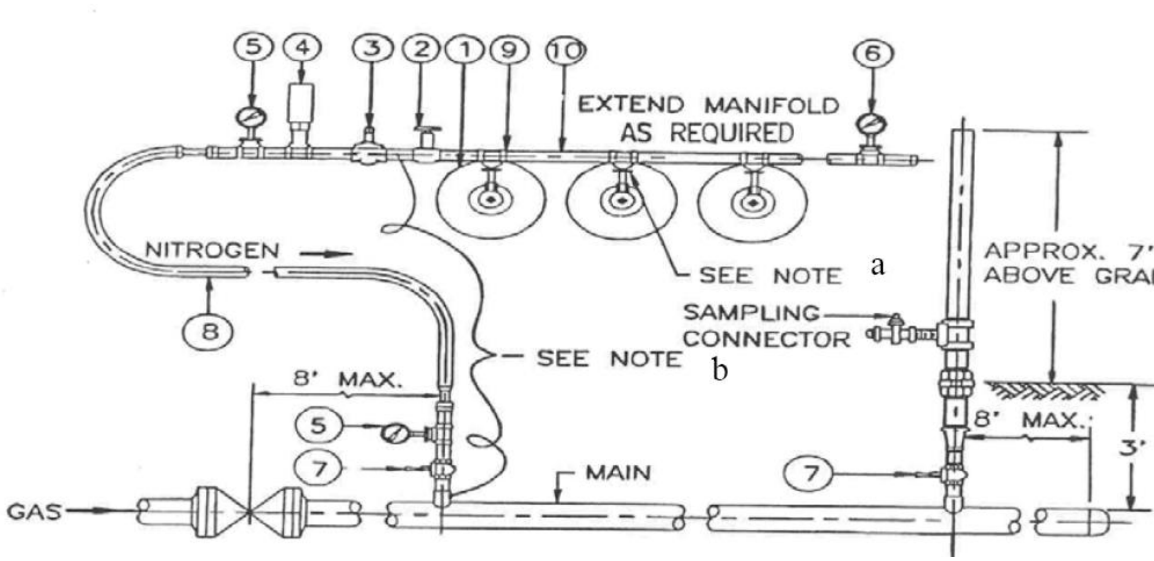


EXHIBIT E

TYPICAL NITROGEN N2 PURGE MANIFOLD



1. Standard nitrogen cylinder.
2. ½" needle valve (3000 psig rating).
3. Pressure regulator when required (3000 psig rating – 0 to 100 psig spring range).
4. Relief valve (3000 psig rating – 100 psig setting)
5. Pressure gauge (0 to 100 psig range).
6. Pressure gauge (0 to 2500 psig range).
7. Shut-off valve.
8. Air compressor hose (50 feet).
9. Typical 3000 # forged steel fitting.
10. Typical schedule 80 (min) steel pipe.

Notes:

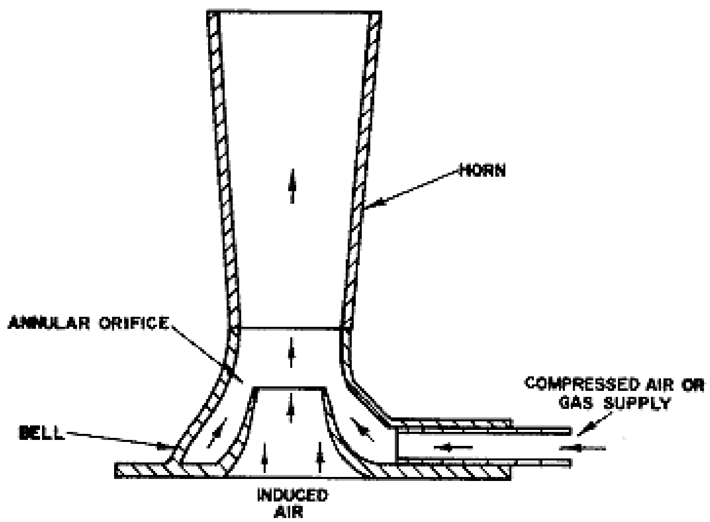
a. Each nitrogen cylinder must have a 0 – 2500 psig pressure gauge connected downstream of the cylinder control valve.

b. If a non-metallic hose connection is used between the manifold and gas main, a # 12 AWG bare, stranded copper bond wire must be installed as shown.

c. The pressure ratings and capacities of all components must be properly selected.

EXHIBIT F

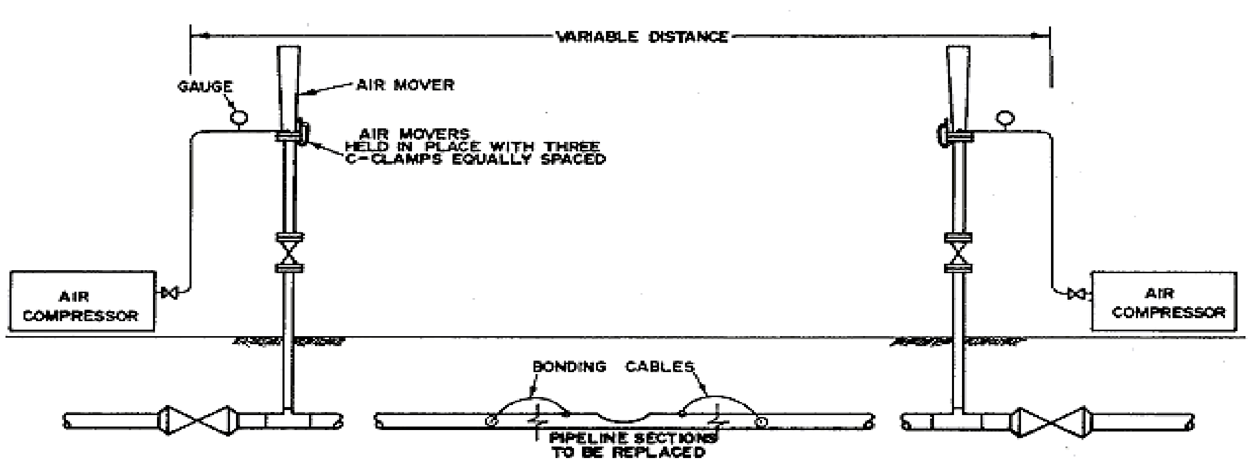
Portable Air Mover



Air movers and/or purgers are essentially portable ventilating devices that have no moving parts. Compressed air is expanded at a high velocity to produce a venturi effect which causes the atmosphere to be removed to be drawn through the bell of the air mover, and exhausted through the outlet horn. A continuous supply of compressed air must be maintained in order to provide a constant updraft.

When an air or purger mover is utilized to purge a section of pipeline, the opening at the inlet to the line being purged must be at least as large as the air mover being used to produce a successful purge with a minimum amount of mixing.

The following illustrates how air movers can be used to eliminate an explosive mixture from a work area.



NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Patrolling Distribution Systems	Standard Number: GS 1702.010(KY)
Supersedes: 01/01/2014		Page 1 of 2

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.721, 192.613; KY 807 KAR 5:022 Section 14, 5:006 Section 26(3)

1. GENERAL

Patrolling is the act of observing for visual evidence of potentially hazardous conditions that could affect the safe operation of the distribution system.

Conditions which are potentially hazardous may be unique to each facility being observed and may include one or more of the following.

a. Visual evidence of leakage.

b. Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports such as bridges, piling, headwalls, casings, and foundations.

c. Deformations of the pipeline or support mechanisms due to expansion and/or contraction.

d. Land subsidence, earth slippage, soil erosion, flooding, climatic conditions, and other natural causes which can result in impressed secondary loads.

e. Need for additional repair or replacement of pipeline identification and line markers.

f. Inlet and outlet lines of regulator stations subject to movement due to frost.

g. The presence of atmospheric corrosion and/or inadequate condition of protective coatings on exposed piping.

2. IDENTIFICATION OF AREAS TO BE PATROLLED

Segments of distribution systems, which, because of actual or potential exposure to dangerous conditions, require more frequent observation than is provided by leak survey programs, valve inspection or regulator inspection programs, shall be identified in order to establish a patrolling schedule.

Effective Date: 01/01/2016	Patrolling Distribution Systems	Standard Number: **GS 1702.010(KY)**
Supersedes: 01/01/2014		Page 2 of 2

To identify those segments of a distribution system that will require more frequent observations, and therefore will be assigned for patrolling, consideration should be given but not limited to the following locations:

a. bridge crossings,

b. aerial crossings,

c. unstable river banks,

d. exposed water crossings,

e. areas susceptible to washout,

f. landslide areas,

g. areas susceptible to earth subsidence, such as mines and landfills,

h. tunnels,

i. railroad crossings,

j. attachments to buildings or other structures,

k. facilities or support structures which require maintenance, until repaired , and

l. roof-top mains.

3. FREQUENCY

The frequency of patrolling distribution mains shall be determined by the severity of the conditions which could cause failure or leakage and potential hazard to public safety. Distribution mains located in places or on structures where anticipated physical movement or external loading, beyond design, could cause failure or leakage, shall be patrolled at intervals not exceeding four and one-half (4-1/2) months, but at least four (4) times each calendar year.

Patrolling may be accomplished in conjunction with leakage surveys, scheduled inspections, line locating, or other routine activities.

4. REMEDIATION

Deficiencies found during the patrol shall be reported to supervision and appropriate action taken to correct the problem or minimize risk.

5. RECORDS

The date and time of the patrol shall be recorded in the electronic WMS Job Order execution remarks field.

Patrolling records shall be kept in the work management system or equivalent for at least ten (10) years, plus the current year.

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Patrolling Transmission Lines	Standard Number: GS 1704.010(KY)
Supersedes: 01/01/2014		Page 1 of 3

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.705, 192.613, 192.709; KY 807 KAR 5:022 Section 6, 5:006 Section 26(3)

1. GENERAL

Patrolling is the act of observing for visual evidence of potentially hazardous conditions that could affect the safe operation of the transmission line.

The Company's patrol program for transmission lines shall include the observation of:

a. presence and condition of line markers,

b. surface conditions attributed to leakage,

c. construction activity,

d. right-of-way encroachment, and

e. other factors affecting safety and operations which may include, but are not limited to, washouts, normally covered exposed pipe, unusual surface conditions, vandalism, or damaged vents.

2. PATROL METHODS

Facility patrols may be performed by any of the following methods:

a. walking,

b. driving,

c. flying, or

d. other appropriate methods of observing the right-of-way.

3. FREQUENCY

The interval between patrols is typically specified within the Company's Pipeline Integrity Management Program (IMP). Refer to the IMP written manual for intervals for each pipeline. If the interval is not described in the manual, the intervals shall be as follows:

Class location of line	Maximum intervals between patrols: At highway and railroad crossings	Maximum intervals between patrols: At all other places
1 and 2	7 1/2 months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year
4	4 1/2 months; but at least four times each calendar year	4 1/2 months, but at least four times each calendar year

Patrolling may be accomplished in conjunction with leakage surveys, scheduled inspections, line locating, or other routine activities.

4. REMEDIATION

Deficiencies found during the patrol shall be documented within the comments section of the Company's work management system and reported to local leadership.

For conditions that pose a threat to pipeline safety, the leader shall report the deficiency to personnel responsible for the Transmission Integrity Management Program (TIMP). TIMP personnel shall engage others as needed (e.g., Engineering, etc.) and select the appropriate remedial action to correct the problem or minimize risk.

Selection of remedial measures shall include consideration if temporary measures are needed until the permanent implementation is accomplished. For washouts, temporary measures could include visual examination of exposed pipe, evaluation of the impacts of the condition on the corrosion control system, or more frequent patrols (e.g., monthly). The remediation schedule shall consider the risk posed by the condition.

Issues which require replacement due to an unplanned exposure should be completed within two years, unless factors exist which make this impractical. For conditions in which the remediation will exceed six (6) months, a Preventive and Mitigative Measure shall be established in accordance with IMP 6-07 “Preventive and Mitigative Measures” of the Company's TIMP written plan. This will provide for an annual review of the progress of the remediation to ensure sufficient progress is being made and that any temporary measures are adequate and effective.

5. RECORDS

The date and time of the patrol shall be recorded in the electronic WMS Job Order execution remarks field.

Patrolling records shall be kept in the work management system or equivalent for as long as the segment of transmission line involved remains in service.

Where a record is established in accordance with IMP 6-07 of the TIMP plan, such records must be retained for the life of the pipeline.

Distribution Operations

Gas Standard

Effective Date: 08/01/2010	**General Policy for Gas Leakage Inspection and Control**	Standard Number: **GS 1708.010**
Supersedes: N/A		Page 1 of 2

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

Each Operating Center shall have a leakage inspection and control program to locate and control gas leakage.

The provisions of the GS 1708 Series and 1714 Series of gas standards do not apply to privately-owned, master metered distribution systems, such as:

a. mobile home parks,

b. associations,

c. colleges or universities,

d. apartments or housing complexes, and

e. industrial complexes.

2. RESPONSIBILITY

The Operations Center Manager has the overall responsibility within their Operations Center for implementation of the leakage inspection and control programs.

3. QUALIFICATION OF PERSONNEL

Leakage surveys, classification, and clearance shall be performed by qualified personnel with training and experience gained through association with leakage work.

4. REPORTS FROM OUTSIDE SOURCES

Any notification of an odor, leak, explosion, or fire, which may involve gas facilities, received from an outside source, such as police/fire department, other utility, contractor, customer or the general public shall be investigated promptly. If the investigation reveals a leak, the leak shall be classified and action taken accordingly. Refer to the Company's *Emergency Manual* and GS 1714.010 "*Leakage Classification and Response*."

5. ODORS OR INDICATIONS FROM FOREIGN SOURCES

If an odor or indication is found to originate from foreign sources, i.e., gasoline vapors, sewer or marsh gas, another utility, or customer owned piping, appropriate action shall be taken where necessary to protect life and property. Conditions that are potentially hazardous shall be reported promptly to the operator of the facility and, when appropriate, to the police/fire department or other governmental agencies. Refer to GS 1708.070 "*Investigation of Gas Indication from an Unknown Source*."

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Leakage Surveys	Standard Number: **GS 1708.020(KY)**
Supersedes: 01/01/2015		Page 1 of 9

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.706, 192.709, 192.723, 192.935(d), 192.1011; KY 807 KAR 5:022 Section 14(6, 13), 5:006 Section 26(3)

1. GENERAL

Leakage surveys of distribution systems such as mains, service lines, and pressure regulating stations shall be conducted using a combustible gas indicator, flame ionization equipment, or other Company approved leak detector equipment.

Leakage surveys of transmission lines shall be conducted. The leakage survey may be conducted by using leak detector equipment or by a vegetation survey. However, the leakage survey of a non-odorized transmission line shall be conducted using leak detector equipment.

Equipment used by contractors but not by the Company may be used as long as the Company approves its use.

All equipment utilized for leakage surveys shall be operated in accordance with the manufacturer's instructions.

GS 1714.010(KY) “Leakage Classification and Response” provides requirements for classifying leaks and leak response.

2. TYPES OF SURVEYS

2.1 Business District

Business Districts are defined as areas within pavement from building wall to building wall including the main and where the principal commercial activity of the city or town takes place.

The “principal commercial activity of the city or town” means the primary location(s) in the city or town used mainly in the conducting of buying and selling commodities and service, and related transactions, where the majority of buildings on either side of the street include, but are not limited to, banks, shops, offices, theaters, drug stores, court house, restaurants, stadiums, hospitals, clinics, religious buildings, educational buildings, etc.

A Business District does not typically consist of only one or two commercial buildings.

The following should also be considered in determining Business Districts.

a. Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.

b. Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.

c. Any other area that, in the judgment of the operator, should be so designated.

The rationale for performing Business District Leakage Surveys is that there is an increased potential for an underground natural gas leak to migrate due to continuous paved surfacing and below grade utility conduits up against a building foundation where many people congregate for business or other purposes.

2.1.1 Roles and Responsibilities

The System Operations Manager is responsible for establishing and maintaining the Business Districts, with input from the Operations Center Manager or Leadership, Engineering, GIS, and others that may provide resources and information.

2.1.2 Leakage Surveys Conducted in Business Districts

A leakage survey, using leak detector equipment must be conducted in Business Districts of all mains and services, including tests:

a. of the atmosphere in any underground substructures such as, but not limited to, gas, electric, telephone, sewer, and water system manholes,

b. at cracks in pavement and sidewalks,

c. across building walls facing the gas piping as well as accessible adjacent walls, and

d. at other locations providing an opportunity for finding gas leaks.

Refer to Section 2.3 for additional guidance on service lines.

2.1.3 Maintenance of Business Districts

Business Districts and areas outside of Business Districts should be evaluated during leakage surveys to identify additional areas to be considered for additions and/or deletions to the current Business District Leakage Survey.

Persons performing leakage surveys shall report proposed additions and/or deletions to Systems Operations or designee (i.e., Integration Center). Systems Operations shall investigate and verify proposed additions and/or deletions and submit changes to the existing Business District Leakage Survey to the Integration Center.

Updates shall be made to the Business District Leakage Survey records (i.e., WMS RT, maps or GIS) prior to the next scheduled Business District Leakage Survey.

2.2 Outside Business District

Facilities not included in the “Business District” are considered “Outside Business District.”

A leakage survey, using leak detector equipment must be conducted Outside Business Districts of all mains and services, including tests:

a. of the atmosphere venting from any nearby underground substructures such as, but not limited to, gas, electric, telephone, sewer, and water system manholes,

b. at cracks in pavement and sidewalks, and

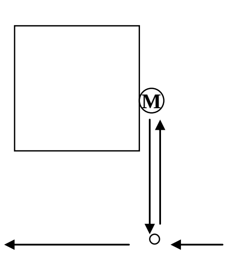
c. at other locations providing an opportunity for finding gas leaks.

Refer to Section 2.3 for additional guidance on service lines.

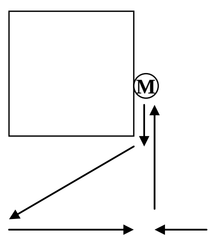
2.3 Service Lines

Leakage surveys shall be conducted over the entire length of the service line up to the outlet of the meter or to the connection to the customer's piping, whichever is further downstream. However, portions of service line (e.g., tap to curb valve, curb valve to foundation, inside meter) could be leak surveyed separately. Leakage surveys on portions of the service lines may be accomplished by qualified individuals in conjunction with other scheduled inspections (e.g., main survey) or other routine activities (e.g., meter reading). Refer to GS 1708.022 “Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities” for additional guidance for leakage surveys performed on inside meters.

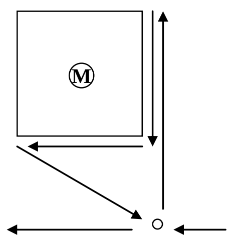
The following are examples of acceptable leakage survey patterns for service lines.



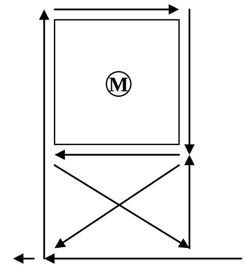
Meter and Curb
Valve or Tap
Location Known



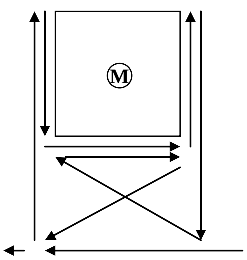
Meter Location Known,
Curb Valve or Tap
Location Unknown



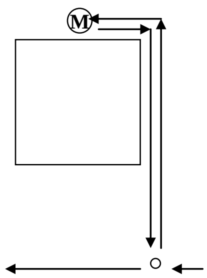
Meter Inside, Curb
Valve or Tap
Location Known



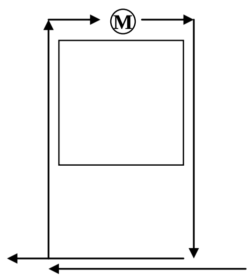
Meter Inside, Curb Valve or
Tap Location Unknown,
Back Accessible



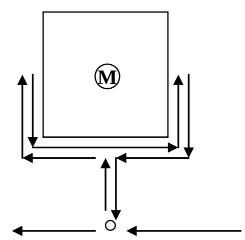
Meter Inside, Curb Valve
or Tap Location Unknown,
Back Inaccessible



Meter In Back, Curb
Valve or Tap
Location Known



Meter In Back, Curb
Valve or Tap
Location Unknown



Meter Inside, Curb Valve
or Tap Location in Center
of House

Note: Consideration should be given to situations where more than one possible service route exists and the actual location of the service line is not known such as in the case of corner properties or large buildings.

2.4 Designated Building/Areas or Special Survey

In business districts, a leakage survey shall be conducted at inside basement walls of public and commercial buildings located adjacent to gas mains and service lines where access is not denied. The survey shall include tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance. However if the meter is located inside, the leakage survey must include the service line up to the outlet of the meter.

The leakage survey may include the following.

a. Tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance.

b. Inform the person in charge of the building the reason for the inspection.

c. Inspect the service entrance, the service regulator and gas meter installation for severe corrosion or other unsafe conditions.

d. Inspect the inside shut-off for condition and accessibility.

e. Conduct leakage tests at meter installation, at point of entry of gas, water, sewer, and duct lines, and at any large cracks along street wall in the basement. Notify the Logistics/Integration/Work Management Center if leaking gas is found to be entering building.

f. Visually inspect regulator vents to assure that they are clear. Any vent located so as to direct blowing gas toward a window or cause gas to enter the building shall be reported for relocation.

g. Verify that the curb valve is identifiable and readily accessible wherever a curb valve is installed.

2.5 Rooftop or Vertical Piping

Leakage surveys of Company facilities that are located on a rooftop or vertically along a multi-story or high-rise building shall be conducted along the mains and/or service lines up to and including the outlet of the customer meter(s).

The pipe supports shall be visually inspected to identify whether damage has occurred to the support, roof or pipe and if the pipe is being supported.

Pipe coating, including paint, shall be inspected to identify areas of disbonding, scratches, or scrapes. Damage to the pipe coating is most likely to occur where the pipe is in contact with the pipe supports. Observe for atmospheric corrosion and report the presence of atmospheric corrosion according to GS 1450.010 “Atmospheric Corrosion.”

2.6 Supplemental Leakage Surveys

2.6.1 Winter Leakage Surveys

Winter leakage surveys are optional surveys conducted in order to detect potentially hazardous situations caused by frost damage. These surveys are initiated by reasonable frost penetration and may continue periodically throughout the winter as the frost penetration deepens. A final leakage survey in the spring of the year, once the frost is gone, should be considered.

Checks should be made at all available openings, including manholes, catch basins, cable ducts, etc. and along or at building walls adjacent to gas facilities. This should be done especially where gas facilities are in close proximity to building walls.

Areas to be considered for conducting winter patrol surveys include the following:

a. Business Districts,

b. areas containing cast iron facilities,

c. areas subject to extreme frost penetration due to surface conditions such as concrete, asphalt, and gravel,

d. areas having historically high incidence of leaks, and

e. areas containing known leaks where migration could result in a hazardous condition.

2.6.2 Other Supplemental Leakage Surveys

Supplemental leakage surveys are performed as a result of other operating conditions such as uprates, third party encroachments, weather, etc. Supplemental leakage surveys shall be considered when the pipeline is subjected to unusual stresses due to, but not limited to; earthquakes, blasting (refer to GS 1100.020 "Damage Prevention – Blasting Activities"), trenchless installation of foreign buried facilities that cross gas pipelines, high construction activity, heavy equipment, subsidence, landslides, and flooding. Where it is reasonable to expect that leakage will occur as a result of the unusual stresses, a leakage survey shall be performed over the affected pipeline.

Additional consideration should be given to performing leakage surveys for the following conditions.

a. Before and after scheduled activities or encroachments that may impact the pipeline.

b. Prior to paving activities, especially if the pipeline facilities are unprotected and located under the pavement. This will allow for the evaluation and completion of the possible repairs or replacement of the pipeline prior to the paving activity.

3. VISUAL OBSERVATIONS

Unusual situations such as pipeline/easement encroachments (e.g., structures over the pipeline, excessive vegetation, third party excavation, etc.), abnormal operating conditions (e.g., atmospheric corrosion, damaged coating or pipeline, exposed pipelines, missing vents, excessive icing at regulator settings, etc.), or inaccurate or missing pipeline markers observed as leakage surveys are being performed shall be reported to the front line leader/supervisor.

Unusual situations encountered on transmission lines shall be promptly reported by the front line leader/supervisor to the personnel managing the Pipeline Integrity Program (e.g., System Operations Manager).

4. LEAKAGE SURVEY FREQUENCIES

4.1 Distribution Systems

Leakage survey frequencies should be based on the survey type, operating experience, sound judgment, and knowledge of the distribution system. Once established, frequencies should be reviewed periodically to affirm that they are still appropriate. The person performing the leakage inspection or personnel having knowledge of the survey should notify the front line leader/supervisor when established leakage survey frequencies are no longer appropriate. Leakage surveys may be accomplished in conjunction with patrolling, scheduled inspections, and other routine O&M activities.

Table 1 shows the leakage survey frequencies for business districts, outside of business districts, designated buildings/areas, and special surveys. These survey frequencies are based on federal and state regulations.

Table 1

Distribution System Leakage Survey Frequencies		
Business District	**Outside of Business District**	**Designated Building/Areas or Special Survey**
Once each calendar year not to exceed 15 months	As needed, but at least once every 5 years not to exceed 63 months for plastic/protected steel pipelines And Once every 3 years at intervals not exceeding 39 months for cast/ductile iron and unprotected steel pipelines	In conjunction with the business district survey, where access is not denied, leak survey at inside basement walls of public and commercial buildings located adjacent to gas mains and service lines. Jurisdictional Rooftop and/or Vertical Piping: Once each calendar year not to exceed 15 months

4.2 Transmission Lines

Table 2 shows the minimum leakage survey frequencies for odorized and non-odorized gas transmission lines for different class locations. Use the non-odorized frequencies when leak surveying Company owned facilities at a city gate (town border) station that is supplied with non-odorized gas.

Table 2

Transmission Line Leakage Survey Frequencies		
DOT Class Locations	**Odorized Gas**	**Non-Odorized Gas**
1 & 2	Once each calendar year not to exceed 15 months[1]	Once each calendar year not to exceed 15 months
3[1]		Twice each calendar year not to exceed 7 ½ months[1]
4[1]		Four times each calendar year not to exceed 4 ½ months

[1]As required by IMP- 6-07 "Preventive and Mitigative Measures," of the Company's Transmission Pipeline Integrity Management Program, transmission pipeline segments operating below 30% SMYS and within Class 3 or Class 4 locations, but not within a High Consequence Area, perform semi-annual leak surveys (quarterly leak surveys for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

4.3 Other Frequency Considerations

Consideration should be given to increased frequency for leakage surveys based on the particular circumstances and conditions. Surveys should be conducted most frequently in those areas with the greatest potential for leakage and where leakage could be expected to create a hazard. Factors to be considered in establishing the frequency of leakage surveys include the following.

a. Piping system, including age of pipe, materials, type of facilities, operating pressure, leak history records, and other studies.

b. Known areas of significant corrosion or areas where corrosive environments are known to exist.

c. Piping location, including proximity to buildings or other structures and the type and use of the buildings and proximity to areas of concentrations of people.

d. Environmental conditions and construction activity that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard.

e. Any other known condition that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard.

5. RECORDS

Leakage information is to be recorded according to the requirements in GS 1708.100 “Leakage Control Records.” The date and time of the leakage survey shall be recorded in the electronic WMS Job Order execution remarks field.

For distribution systems, retain records of each leakage survey for ten (10) years, plus the current year.

For transmission lines, retain records of each leakage survey for as long as the segment of transmission line involved remains in service.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities	Standard Number: **GS 1708.022**
Supersedes: 01/01/2015		Page 1 of 6

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192.723, 192.481, 192.491

1. GENERAL

This gas standard provides guidance for completing leakage surveys and atmospheric corrosion inspections on pipeline facilities up to and including the outlet of meter that are located inside a building.

The service entrance into the building (on the inside of the building) shall be inspected for leakage and visually inspected for atmospheric corrosion. In addition, exposed piping and appurtenances downstream of the service entrance into the building up to and including the outlet of the meter(s) shall be inspected for leakage and visually inspected for atmospheric corrosion.

Pipeline facilities to be inspected include, but are not limited to the following.

a. Exposed service piping and appurtenances.

b. Meters.

c. Swivels.

d. Pre fab meter settings.

e. Regulators and regulator vent lines if so equipped (including vent terminal(s)).

f. Valves.

For additional guidance, refer to the applicable GS 1708.020 “Leakage Surveys” and GS 1450.010 “Atmospheric Corrosion.”

2. COMPLETING THE INSIDE LEAKAGE SURVEY AND ATMOSPHERIC CORROSION INSPECTION

Whenever a Company employee is working at a customer’s premises and the meter and/or any portion of the service line piping is located indoors, and the employee is qualified to do so, a leakage survey and atmospheric corrosion inspection shall be conducted on exposed service piping up to and including the meter, with the following exception.

EXCEPTION: Employees working collection and/or theft/fraud investigation, or when posting notices related to those activities are exempted from completing the leakage survey and atmospheric corrosion inspection.

The inside portion of the leak survey shall be conducted using any of the following methods.

a. Combustible gas indicator (CGI).

b. Company approved gas detector (e.g., Tif, Gastrac), provided that any indication of leakage shall be confirmed with a combustible gas indicator or a soap test.

c. Company approved infrared leak detector (e.g., Heath DP-IR Leak Detector).

Turn on the leak detection instrument in the outside free air; set scale on the appropriate scale for the investigation to be conducted (e.g., %LEL, monitor mode); and zero the instrument before proceeding into the building.

Beginning at the service entrance in the building, leak survey and visually inspect for atmospheric corrosion on exposed piping and appurtenances (e.g. meters, swivels, pre-fab meter settings, regulators and regulator vent lines if so equipped [including regulator vent terminal(s)], valves, etc.) up to and including the outlet of the meter(s).

If atmospheric corrosion is discovered during the survey, obtain the appropriate order(s) and/or submit a “Further Action Required” for remediation.

Any leakage found shall be investigated immediately according to GS 1708.060 “Inside Leak Investigation” and classified in accordance with the applicable GS 1714.010 “Leakage Classification and Response.”

See the applicable GS 1450.010 “Atmospheric Corrosion” for additional guidance.

3. RECORDS

Document the completion of the leakage survey and atmospheric corrosion test on the MDT job order and/or in the Work Management System. For employees assigned an inaccessible inspection order - SOII – and multiple meters exist in the premises, an inspection shall be conducted for all accessible meters located inside the premises. Obtain a separate order – SOII - for each meter/PSID located inside the premises to document the completion of the inside leakage survey and atmospheric corrosion inspection.

Select “Yes” from the dropdown box on the MDT DIS job order indicating the completion of the inside service line leakage survey and atmospheric corrosion test.

a. For order types: MC, OS, NS, DC, RI and RA – see Exhibit A.

b. For order types: PR, CO, AP, CH, CN, CS, FA, HB, IX, NP, RC, RD, RR, RX, SC, SI and SO – see Exhibit B.

By selecting “Yes” on the MDT DIS job order “Inside CSL Leak/Corr Inspection Complete” field on the MDT job order, the "Inside Inspect" date in the Service Line Inquiry Control Data Entry in DIS will be updated to reflect the date of the inside leakage survey and atmospheric corrosion inspection – see Exhibit C.

Grade 1 leaks on jurisdictional facilities (i.e., upstream of the outlet of the meter or the connection to the customer's houseline) shall be recorded on Form 1708.100-1, "Distribution Plant Inspection and Leakage Repair" (DPI or leak order). Refer to GS 1708.100 "Leakage Control Records" for more information.

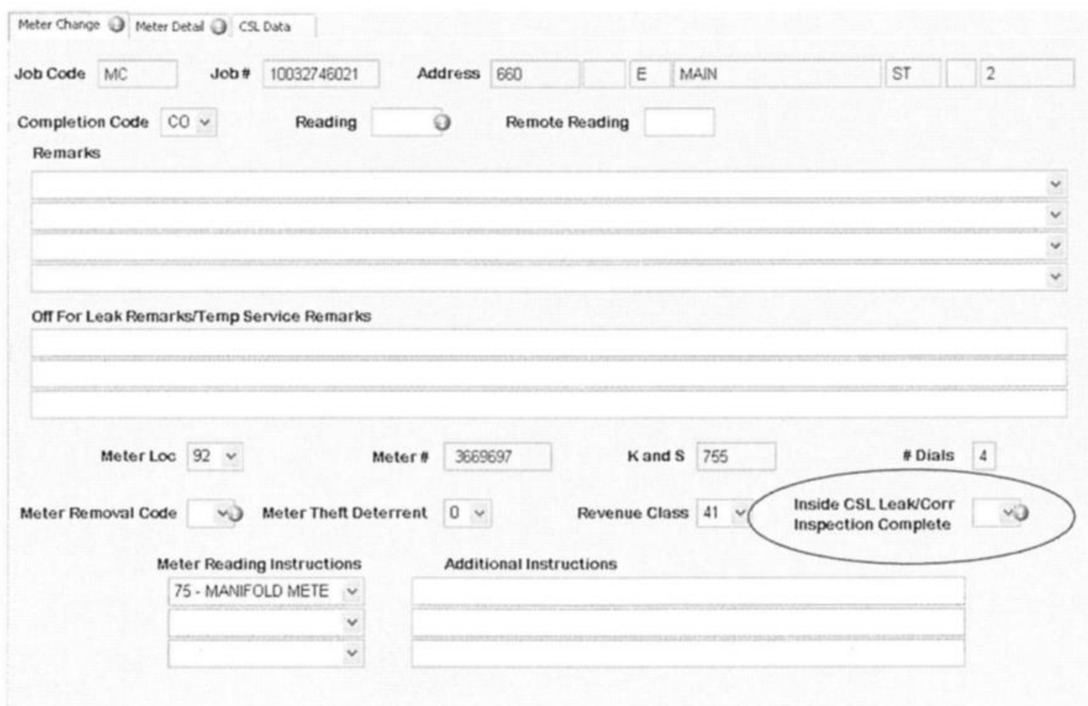
Refer to the applicable GS 1450.010 "Atmospheric Corrosion" for documentation requirements.

Leakage survey and atmospheric corrosion inspection and remediation records shall be retained for a minimum of ten (10) years, plus the current year.

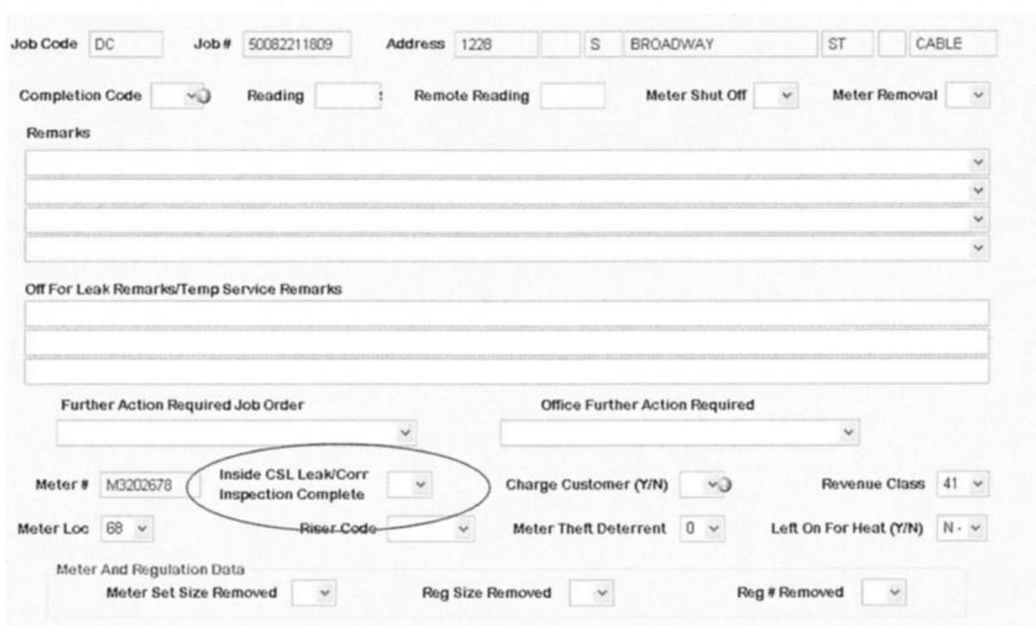
Effective Date: 01/01/2016	Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities	Standard Number: **GS 1708.022**
Supersedes: 01/01/2015		Page 4 of 6

EXHIBIT A

For the MC order group (MC, OS, NS)



For the DISCONNECT order group (DC, RI and RA)



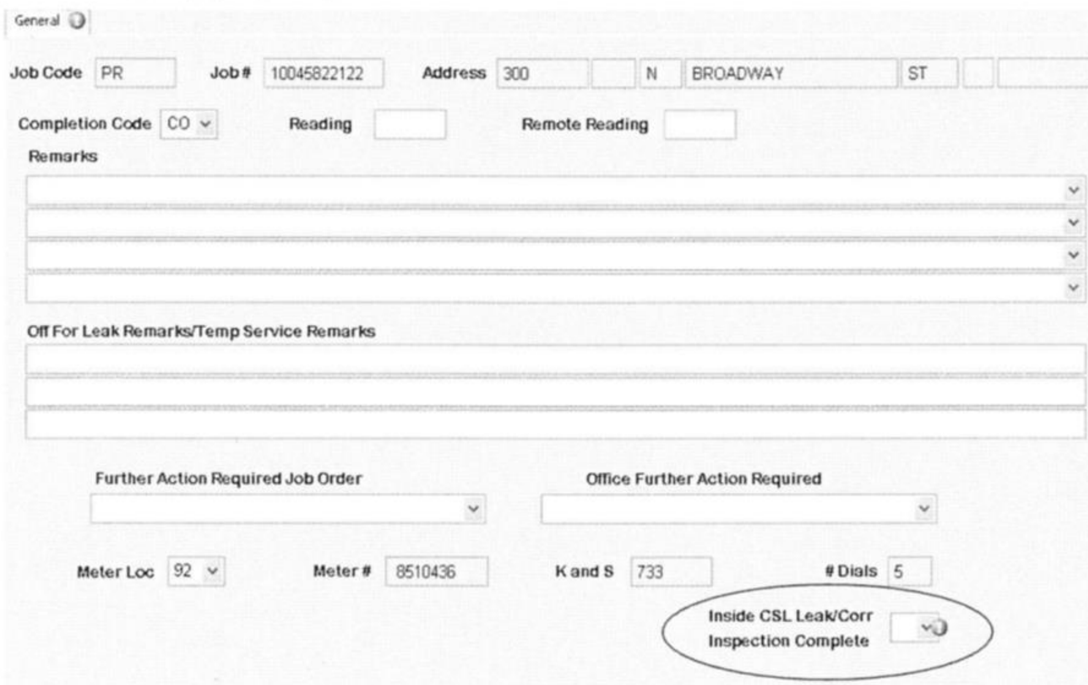
NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Conducting Leakage Surveys and Atmospheric Corrosion Inspections on Inside Pipeline Facilities	Standard Number: **GS 1708.022**
Supersedes: 01/01/2015		Page 5 of 6

EXHIBIT B

For the PR order group (PR, CO)


General

Job Code PR Job # 10045822122 Address 300 N BROADWAY ST

Completion Code CO Reading Remote Reading

Remarks

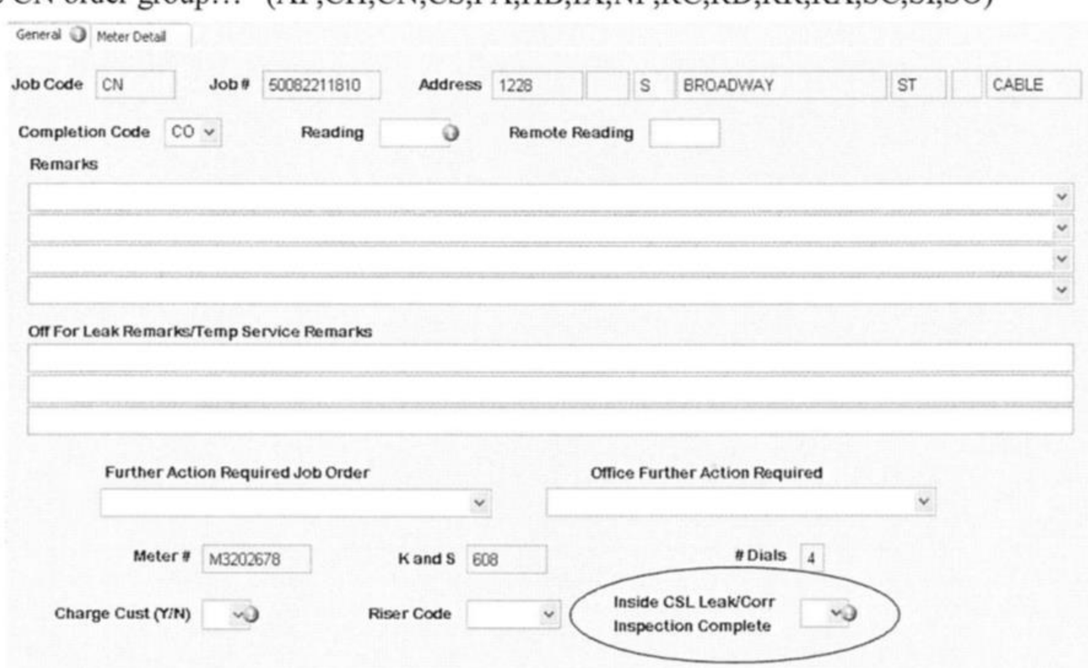
Off For Leak Remarks/Temp Service Remarks

Further Action Required Job Order Office Further Action Required

Meter Loc 92 Meter # 8510436 K and S 733 # Dials 5

Inside CSL Leak/Corr Inspection Complete

For the CN order group… (AP,CH,CN,CS,FA,HB,IX,NP,RC,RD,RR,RX,SC,SI,SO)


General Meter Detail

Job Code CN Job # 50082211810 Address 1228 S BROADWAY ST CABLE

Completion Code CO Reading Remote Reading

Remarks

Off For Leak Remarks/Temp Service Remarks

Further Action Required Job Order Office Further Action Required

Meter # M3202678 K and S 608 # Dials 4

Charge Cust (Y/N) Riser Code Inside CSL Leak/Corr Inspection Complete

EXHIBIT C

```
OPER-ACTION ____     SERVICE LINE INQUIRY PG 1   37 2421    400018851    12/23
CUST NAME                                            PCID          CUST
SERV ADDR 127 W MARKET ST                                CHECKFREE-ZIPCHECK
     CITY YORK                  ST PA ZIP 174011314  ACTIVE, PAYMENT POSTED
LOCKDOWN:                                  UNSAFE:
NO BURIED REGULATORS 0                        SERVICE REG CD     0 00
OUTSIDE INSPECT 02 2012    SCHED CD I         CSL ROUTE/SEQ     2260  0342.00
INSIDE  INSPECT 05-02-2012                    PREMISE STATUS    ACTIVE
LEA NO                                        METER K&S         612
METER NO       6004103 ROUTE SEQ 0084         MEAS STATION NO   000000-0
TAX DISTRICT  1333095                         MAIN NO           37001001P1177
MASTER MTR CD                                 TCO LOC NO
OPER PRSURE   LP     CSL PRSURE  MP           MAP NO            55-55
MAIN CODE:     SIZE  060    MATL  P           LOC REFERENCE     8NSCU
SERVICE PIPE:  SIZE  020    MATL  P           LENGTH OF SERV    00028    00024
SERVICE PIPE2: SIZE  020    MATL  P           SPECIAL COND          C
OWNER   COMPANY OWNED                         EFV          SADC  YC
INS/ABN DATE  00 00 1978  04 02 1993      SHUT-OFF INFO GAS TURNED ON
REPAIR DATE   00 00 0000  00 00 0000      REPAIR KIND
MASTER TAP CODE        RISER CODE         MASTER TAP LOC/PSID
CURB BOX LOC/PSID    5LRB    24FFB        CUST VALVE LOC/PSID  METER VALVE
F1=HELP    F2=WRK-FUN    F3=QUIT    F4=ORD-TAK    F5=INQ    F6=ORD-EX    F8=FWD
F9=INQ-CTL       F10=EX-CTL       F11=TAK-CTL       F14=CONTACT       F24=CASH
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NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2015	Leakage Survey and Test Methods	Standard Number: **GS 1708.030**
Supersedes: 01/01/2014		Page 1 of 5

Companies Affected:

☑ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.706, 192.723

1. GENERAL

There are several methods for performing leakage surveys and tests to detect the presence of natural gas. The following information explains the different methods of Leakage Surveys and Tests, when each should be used, and how each should be performed.

All equipment utilized for gas detection shall be operated in accordance with the manufacturer's instructions. Equipment used by contractors but not by the Company may be used as long as the Company approves its use.

For all leakage surveys, set the equipment to the most practical sensitive scale available to register the level of gas present.

For LDCs operating liquefied petroleum gas (LPG or propane) distribution systems see GS 1708.050 “Propane Systems Leakage Survey and Test Methods.”

2. LEAKAGE SURVEY AND TEST METHODS

2.1 Surface Gas Detection Survey

Surface gas detection surveys (surface surveys) are a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above-ground gas facilities.

Surface surveys are based on the detection of gas venting into the atmosphere. Weather or soil conditions which might reduce the amount of gas venting into the air or dilute the sample shall be taken into consideration. If such conditions exist in the area to be inspected, considerations should be given to reducing the speed of the survey, postponing the survey, or employing another survey method. The survey should be conducted at speeds 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, parked cars, and any adverse conditions such as wind, rain, ice, and frost which might exist.

Surface gas detection surveys must be conducted with leak detection equipment, approved for surface surveys, such as flame ionization, multi-purpose instruments set in the survey mode, or infrared, using the most practical sensitive scale. Samples should be taken from all available (accessible) openings including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, catch basins, utility valve boxes and vaults, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks such as unpaved surfaces (lawns), curb lines, or sidewalk seams.

When conducting a mobile leakage survey, vehicle speed shall not exceed 5 mph. Exception, vehicle speed for Winter Leakage Surveys (GS 1708.020, GS 1708.020(MA), GS 1708.020(MD), GS 1708.020(KY), or GS 1708.020(PA) “Leakage Surveys”) should not exceed 10 MPH.

For programmed compliance inspections, utilization of the surface survey is the preferred method. The surface survey can also be used to assist with odor investigations.

2.2 Subsurface Gas Detection Survey

Subsurface gas detection survey (subsurface survey) is the sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting natural gas at the sample point. Subsurface surveys must be performed by taking a series of tests with an approved combustible gas indicator (CGI) in a series of sample points (bar holes and available openings) adjacent to the gas pipeline facility. The location of the gas facility and its proximity to buildings and other structures are considered when spacing the sample points. Sample points should be as close to the gas facility as possible and spaced along the route of the facility at close enough intervals to accomplish a thorough survey.

The sampling pattern should include bar holes adjacent to service taps, street intersections, ditch crossings, curb lines, pavement edges, at known branch connections, and adjacent to service lines at the building wall. Also sample all available openings, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, catch basins, utility valve boxes and vaults, and at other locations providing an opportunity for finding gas leaks.

A subsurface survey shall be used to detect, verify, or classify leakage.

NOTE: GS 1708.055 “Performing Barholing” states, “Bar holes should be placed no closer than 20 inches from the outside edge(s) of the gas facility.” Refer to GS 1708.055 “Performing Barholing” for additional guidance.

2.3 Vegetation Survey

A vegetation survey is a leakage survey made for the purpose of finding leaks in underground piping by observing vegetation.

In some states, a vegetation survey may be used as the sole method for performing a leakage survey on odorized transmission lines in any class location or on non-odorized transmission lines in Class 1 or 2 locations. Refer to the applicable GS 1708.020 “Leakage Surveys” for specific requirements.

Vegetation surveys may also be employed to supplement surface and subsurface gas detection surveys utilizing appropriate leak detection equipment.

2.3.1 Utilization

Personnel performing a vegetation survey should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the following.

a. System layout.

b. Amount and type of vegetation.

c. Visibility conditions (such as lighting, reflected light, distortions, terrain, or obstructions).

This survey method should be limited to areas where adequate vegetation growth is firmly established. This survey should not be conducted under the following conditions.

a. When soil moisture content is abnormally high.

b. When vegetation is dormant.

c. When vegetation is in an accelerated growth period such as in early spring.

Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.

2.4 Pressure Drop Test

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

Facilities selected for pressure drop tests should first be isolated and then tested.

Pressure drop tests are used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. This type of test will not provide a leak location and its use is normally limited to service lines. A test conducted on existing facilities solely for the purpose of detecting leakage should be performed at a pressure equal to the operating pressure. The test duration must be of sufficient length to detect leakage.

2.5 Exposed Piping Test

An Exposed Piping Test may be used to detect leakage on exposed pipe, such as meter set assemblies or exposed piping on bridge crossings.

2.5.1 Instrument Test

Exposed piping may be checked for leakage using approved leak detection equipment such as the CGI, semi-conductor, infrared, or FI instruments.

2.5.2 Bubble Leakage Test

Exposed piping may also be checked for leakage by using the application of a soap-water mixture or other approved foam forming solution.

The exposed piping should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of bubbles.

A bubble leakage test may also be used to pinpoint leakage detected by other methods.

3. OTHER LEAKAGE DETECTION INDICATORS

The following leakage detection indicators shall be used in conjunction with the appropriate approved leakage detection method such as surface or subsurface survey.

3.1 Vegetation Indicators

This process utilizes visual observations to detect abnormal or unusual indications in vegetation appearance, such as discoloration, defoliation, stunted or deformed foliage, or plush foliage which may indicate leakage.

3.2 Fungus-Like Growth Indicator

This process utilizes visual observations to detect fungus-like growth in valve boxes, manholes, vaults, etc. that may indicate gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

3.3 Insect Accumulation Indicator

This process utilizes visual observations to detect insect migration to areas of leakage. Look for heavy activity of flies, roaches, spiders, etc. near gas facilities.

3.4 Odor Indicator

This process utilizes sense of smell to detect odor from potential gas leakage. Typically natural gas is odorless; therefore a distinctive odorant is added to make the gas detectable by smell.

3.5 Sound Indicator

This process utilizes sense of hearing to detect potential gas leakage. A hissing sound from bad connections, fractured pipe, corrosion pit holes, etc. near gas facilities is the usual indication. A gurgling sound is often present if the ground is saturated or the facility is below the water table.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2014	Gas Detection Equipment Calibration and Operational Checks	Standard Number: GS 1708.040
Supersedes: 01/01/2013		Page 1 of 3

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE

1. GENERAL

Equipment used for leak detection shall be capable of indicating the presence of the gas that is to be detected. Evaluating leaks and determining the leak grade may require equipment capable of indicating the concentration of gas.

The following equipment shall be calibrated and checked in accordance with this standard to assure accurate and proper operation:

a. natural gas and propane search instruments (e.g., flame ionization),

b. natural gas and propane verification instruments (e.g., combustible gas indicators),

c. carbon monoxide (CO) detection instruments,

d. oxygen (O_2) detection instruments, and

e. odorant detection instruments.

2. OPERATIONAL CHECK

The equipment listed above shall be operated in accordance with the manufacturer's instructions.

When not required by the manufacturer’s instructions, an operational check of the equipment should be completed to assure proper operation prior to use. If a problem is suspected, the equipment shall not be used until it can be properly inspected and the problem corrected.

3. CALIBRATION CHECK

The equipment listed above shall be operated in accordance with the manufacturer's instructions.

The equipment listed above shall be checked for calibration in accordance with Table 1. Any equipment found to be out of calibration shall not be used until it is repaired and calibrated.

Table 1	
Instrument	**Calibration Frequency**
All Instruments	After any repair or parts replacement that could appreciably change the calibration
	Anytime the equipment's calibration is suspected to have changed
Search (e.g., flame ionization)	At intervals not exceeding 4 1/2 months, but at least four times each calendar year
Verification (e.g., CGI)	At intervals not exceeding 4 1/2 months, but at least four times each calendar year
CO	In accordance with Manufacturer's Instructions
O2	
Odorant Detection	

4. GAS SPECIFICATIONS

4.1 HFI Operating Gas

The 60/40 fuel gas mixture (60% nitrogen/40% hydrogen) for HFI gas leak detectors shall be a gravimetrically prepared mixture consisting of 39.60-40.40 mole percent hydrogen in nitrogen. Each cylinder shall contain no more that 0.5 parts per million hydrocarbons, no more than 0.002% other components and be certified for composition and impurities.

4.2 HFI Calibration Gas

The instrument shall be checked with a methane in air mixture certified to be either 50 or 100 parts per million (ppm) (± 10%). A certified gas mixture is one that has been analyzed and guaranteed in writing to be of a specific mixture.

4.3 CGI Calibration Gas

All CGI equipment shall be checked on the LEL Scale with a certified gas mixture of 1.5 to 3% methane.

All CGI equipment shall also be checked on the percent gas scale. A 100% natural gas sample or certified bottle equivalent shall be used for calibration. Gas taken from the local distribution system is acceptable.

4.4 CO Calibration Gas

All CO detection equipment shall be calibrated using a CO in air mixture of 100 ppm +/- 2%.

5. RECORDS

A record of calibration checks shall be kept for all gas detection equipment and maintained for 5 years plus the current year.

NiSource
Distribution Operations

Gas Standard

Effective Date: 08/01/2010	Propane Systems Leakage Survey and Test Methods	Standard Number: GS 1708.050
Supersedes: N/A		Page 1 of 4

Companies Affected:

☐ NIPSCO	☑ CGV	☑ COH	☑ BSG
☐ NIFL	☑ CKY	☑ CPA	
☐ Kokomo Gas	☑ CMD		

1. GENERAL

There are several methods for performing leakage surveys and tests to detect the presence of propane gas. The following information explains the different types of leakage surveys and tests, when each should be used, and how each should be performed.

All equipment utilized for gas detection shall be operated in accordance with the manufacturer's instructions.

NOTE: Equipment used for propane survey must be calibrated for propane. Also, check manufacturer’s instructions for equipment limitations (e.g., MSA Models 60, 62, and 62s cannot be used to accurately measure propane in air).

The two most significant differences between natural gas and propane gas are their specific gravity and flammable limits. Propane gas has a specific gravity of 1.52 which is heavier than air and, therefore, normally does not vent to the surface under normal conditions, unlike natural gas which has a specific gravity of approximately 0.6 which is lighter than air. When propane gas escapes, it tends to settle in low places, and to move along the bottom of ditch lines and substructures unless dissipated by substantial air movement. When conducting tests for leakage on buried propane gas systems, it is essential that samples be taken at or near the pipe, in the bottom of ditch lines and at the low point of substructures.

Hazardous concentrations of propane gas can develop rapidly because of the relatively low LEL. The flammable range of natural gas is approximately five (5) to fifteen (15) percent gas in air compared to two (2) to ten (10) percent gas in air for propane gas. Therefore, when conducting a propane gas system leakage survey, it is essential to remember that the lower explosive limit can be as low as two (2) percent gas in air.

2. LEAKAGE SURVEY AND TEST METHODS

2.1 Surface Gas Detection Survey

Surface gas detection surveys (surface surveys) used for natural gas systems, when properly conducted taking into account that propane gas is heavier than air, may be used adjacent to above ground pipeline facilities. The use of the surface survey as the only survey method is prohibited for use on buried propane gas systems. Propane gas is heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation.

2.2 Subsurface Gas Detection Survey

The subsurface gas detection survey (subsurface survey) shall be conducted by performing tests with a combustible gas indicator (CGI) (capable of detecting 10 percent of the LEL) in a series of bar holes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures) adjacent to the gas facility. The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or pipeline will depend on soil and surface conditions but should never be more than 20 feet apart. Where the facility passes under paving for a distance of 20 feet or less, tests should be made at the beginning and end points of the paved area. Where the paved area over the facility is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive paving, permanent test points should be considered, particularly in low places. The sampling pattern should include tests at potential leak locations such as threaded or mechanical joints, and at building walls at the service riser or service line entrance. All available openings adjacent to the piping facility should be tested.

When testing available openings for propane gas, readings should be taken at both the top and bottom of the structure, such as manholes, valve boxes, etc. When testing subsurface structures (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person, and in which gas could accumulate, or basements, the floor areas, including floor drains, should be thoroughly tested because propane gas can temporarily lie in pockets. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended.

When conducting a CGI survey, all bar holes should penetrate to near the bottom of the pipe in order to obtain consistent and representative readings. CGI readings should be taken at the bottom of the test hole. The probe used should be equipped with a device to preclude the drawing in of fluids. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe and/or coating with the probe bar.

2.3 Pressure Drop Test

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

Facilities selected for pressure drop tests should first be isolated and then tested.

Pressure drop tests are used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. This type of test will not provide a leak location and its use is normally limited to service lines. A test conducted on existing facilities solely for the purpose of detecting leakage should be performed at a pressure equal to the operating pressure. The test duration must be of sufficient length to detect leakage.

2.4 Exposed Piping Test

An Exposed Piping Test may be used to detect leakage on exposed pipe, such as meter set assemblies or exposed piping on bridge crossings.

2.4.1 Instrument Test

Exposed piping may be checked for leakage using approved or evaluated leak detection equipment such as the CGI, semi-conductor, or FI instruments.

2.4.2 Bubble Leakage Test

Exposed piping may also be checked for leakage by using the application of a soap-water mixture or other approved foam forming solution.

The exposed piping should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of bubbles.

A bubble leakage test may also be used to pinpoint leakage detected by other methods.

3. OTHER LEAKAGE DETECTION INDICATORS

The following leakage detection indicators shall be used in conjunction with the subsurface survey.

3.1 Odor Indicator

This process utilizes sense of smell to detect odor from potential gas leakage.

3.2 Sound Indicator

This process utilizes sense of hearing to detect potential gas leakage. A hissing sound from bad connections, fractured pipe, corrosion pit holes, etc. near gas facilities is the usual indication. A gurgling sound is often present if the ground is saturated or the facility is below the water table.

3.3 Vegetation Indicators

This process utilizes visual observations to detect abnormal or unusual indications in vegetation appearance, such as discoloration, defoliation, stunted or deformed foliage, or plush foliage which may indicate leakage.

3.4 Fungus-Like Growth Indicator

This process utilizes visual observations to detect fungus-like growth in valve boxes, manholes, vaults, etc. that may indicate gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

3.5 Insect Accumulation Indicator

This process utilizes visual observations to detect insect migration to areas of leakage. Look for heavy activity of flies, roaches, spiders, etc. near gas facilities.

NiSource
Distribution Operations

Gas Standard

Effective Date: 09/16/2014	**Performing Barholing**	Standard Number: **GS 1708.055**
Supersedes: 02/25/2014		Page 1 of 5

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

REFERENCE 49 CFR Part 192.605

1. GENERAL

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

The purpose of this gas standard is to provide requirements for performing:

"**barholing**" - a technique requiring the manual operation of a purpose-designed tool operated by a single person to create a small hole in order to obtain subsurface gas samples.

Typically, when a combustible gas indicator (CGI) indicates positive gas readings in the barholes, the highest readings are normally found in close proximity to the leaking facility. Therefore, care must be exercised while performing barholing, so that the facility is not damaged by the barholing process.

The following are examples of barholing with a CGI.

a. Conducting an outside leak investigation, including, but not limited to, establishing the perimeter of the leakage area.

b. Conducting an inside leak investigation, and during the course of the investigation, it becomes necessary to extend the investigation outside of the structure and perform subsurface CGI tests.

c. Investigating possible leakage while performing programmed leakage surveys and/or Subsurface Gas Detection Surveys.

d. Reinspection of pending leak orders.

e. Follow-up inspections of closed leak orders.

In addition, this gas standard sets forth the expectation of locating gas facilities prior to barholing, which is required during non-emergency conditions (see Section 3.2 below).

This gas standard is not intended to provide guidance for leakage pinpointing. Typically, gas facilities are/will be located prior to excavation in order to repair the leaking facility. Probing in reasonable proximity to the gas facility is necessary in order to determine the best location to excavate. Refer to GS 1714.030, "Leakage Pinpointing" for additional guidance.

This gas standard is not intended to provide guidance for subsurface investigations of propane (LP gas) systems and/or facilities. Propane (specific gravity of 1.5), is substantially heavier than natural gas (specific gravity of 0.6), and air (specific gravity reference point of 1.0), thus it tends to settle in low places. Refer to GS 1708.050, "Propane Systems Leakage Survey and Test Methods" for guidance on performing leakage surveys on propane (LP gas) systems.

2. SAFETY

To minimize the risk of injury and damage to Company and other underground facilities, the following actions shall be taken by the employee prior to barholing.

a. Use PPE associated with the job.

b. A depth indicator, such as tape or a collar device, shall be used on the probe rod to aid in determining probe depth penetration.

c. Insulated probe bars shall be used and inspected, maintained, and replaced, as necessary.

d. Probe rods should be properly maintained with a blunt or rounded end, inspected for wear and replaced as necessary. Probe rods with a pointed tip shall not be used.

3. LOCATING GAS FACILITIES PRIOR TO BARHOLING

3.1 Emergency Investigation

For the purpose of this gas standard, an emergency investigation shall proceed if there is a suspected indication of a potentially hazardous situation (i.e., Grade 1 leak condition, gas detected inside or near a building, migrating gas).

Prior to barholing the following actions shall be carried out, if possible, without risking life and/or property.

a. When the gas service line enters the building below ground and where access can be gained inside, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

b. If service line and mainline information can be retrieved to give an indication of the location of gas facilities prior to barholing, every effort shall be made to do so.

c. Look for the presence of underground structures to exercise caution to avoid damage. Examples of indications that an underground structure may exist in the area to be barholed include the following.

   i. Aboveground or ground level markers.
   ii. Valve boxes (e.g., water, gas).
   iii. Manhole covers.
   iv. Pedestals.
   v. Electric distribution transformers.
   vi. Telephone, cable and electric drops.

d. Where practical, locate gas facility shut-offs and gain access to them prior to driving barholes.

e. Where practical, remove lids from valve boxes to determine the approximate depth of the facility.

3.2 Non-Emergency Condition

Refer to pipeline records and maps that are available in the field for facility locations prior to barholing and attempt to locate the gas facility using an approved pipe locator. If a locate with an approved locator is unsuccessful (i.e., no tracer wire, break in tracer wire), barhole with caution following the guidance in this gas standard.

If Company records indicate that a curb valve(s) exists, attempt to locate the curb valve(s) and gain access to them prior to driving bar holes in the vicinity of service lines. If a curb valve exists and is not accessible or cannot be found, create a FAR job order in WMS to have the curb valve located and made accessible for future use.

Look for the presence of underground structures to exercise caution to avoid damage. Examples of indications that an underground structure may exist in the area to be barholed include the following.

a. Aboveground or ground level markers.
b. Valve boxes (e.g., water, gas).
c. Manhole covers.
d. Pedestals.
e. Electric distribution transformers.
f. Telephone, cable and electric drops.

3.3 Other Considerations

In non-frost, non-pavement situations, 12 inches should be the standard depth of a typical barhole, but as always, the actual operating circumstances (some of which are outlined below) should dictate the actual depth.

Under frost conditions, judgment should be used to establish appropriate barhole depth if the frost depth exceeds 12 inches.

In addition to frost, other considerations that may require barhole penetrations in excess of 12 inches due to conditions that may inhibit the migration of gas to the surface include, but are not limited to the following.

a. Unusually deep facilities.
b. Soils which have heavy clay content.
c. Soils which contain high concentrations of rock.
d. Extremely wet soil conditions.
e. Paving greater than or equal to 12 inches in thickness.

4. PERFORMING BARHOLING

The guidance contained in this section has been developed to minimize the risk of damage to underground gas facilities while performing barholing.

4.1 Depth

If after attempting to locate, there is still uncertainty regarding the gas facility location, limit barhole depth to less than 12 inches. A depth indicator, such as tape or a collar device, on the probe rod is a practical means of limiting barhole depth to avoid damaging underground gas facilities.

4.2 Barhole Placement

Every attempt shall be made to avoid barholing directly over the gas facility. Bar holes should be placed no closer than 20 inches from the outside edge(s) of the gas facility. One exception is when barholing at the foundation in the immediate vicinity of the outside riser (or service line), barhole between the riser (or service line) and the foundation wall to minimize the potential of damaging the service line.

NOTE: Be aware that some riser types may angle toward the foundation.

4.3 Suspected Damage to a Gas Line

If it is suspected that contact has been made with an obstruction, stop immediately and if no readings are obtained on the CGI, move to another location as the obstruction may be an underground gas facility, If readings are present, an investigation shall commence immediately to determine the leakage perimeter and the leak shall be classified in accordance with GS 1714.010, "Leakage Classification and Response." Call for assistance if necessary, and report the suspected damage to a field leader as soon as practical.

If it is suspected that an underground gas facility was struck and no readings are present, the employee who struck the suspected facility shall consult with a field leader so that a determination may be made if any further action is required, including exposing the facility where contact was believed to have been made. If it is determined that an investigation is warranted, the location of the suspected damage shall be marked with white paint and if excavation is required, all applicable state One Call requirements shall be followed prior to excavation.

4.4 Suspected Damage to Facility Other than Gas

If it is suspected that an underground facility other than natural gas was contacted with the probe rod, the location of suspected contact point shall be marked with white paint and an emergency state One Call notification placed so that a determination can be made as to if and what type of facility may have been contacted. If it appears that an underground facility was contacted based on the locate marks, notify the facility owner of the location where contact may have occurred and report your findings to a field leader.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Inside Leak Investigation	Standard Number: GS 1708.060
Supersedes: 09/16/2014		Page 1 of 7

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE None

1. GENERAL

A reported gas leak or odor takes priority and shall be investigated immediately by qualified personnel.

All equipment (e.g., flashlight, cell phone) taken into the building must be intrinsically safe.

For the purposes of responding to a natural gas emergency, the term "made safe" means that adequate precautionary measures were completed. "Adequate precautionary measures" is defined as action(s) to reasonably ensure the public's safety, which shall be validated by ensuring that the action(s) taken resulted in the gas dissipating and the situation is non-hazardous.

For additional information when responding to a natural gas emergency, refer to GS Series 1150 "Emergency Response" Standards.

2. INITIAL ACTION

The following actions shall be taken.

a. Turn on the Combustible Gas Indicator (CGI) in the outside free air; set scale on the appropriate scale for the investigation to be conducted (e.g., %LEL, monitor mode); and zero the instrument before proceeding into the building.

b. Attempt to gain access by knocking. Do not ring doorbell or operate electrical switches.

c. Before entering the building, take a CGI sample in the free air at the entrance to determine if a hazardous condition does or does not exist inside the building.

d. As you proceed through the building, keep the probe of the CGI in the free air pointing towards the ceiling and continually sample the atmosphere.

If inside access cannot be gained, instruct the Integration/Work Management Center or other designee to call emergency services to provide access to the premises to complete the investigation. Gas shall be shut-off if access cannot be gained. In addition, when access is not granted or denied by emergency services, notify local leadership and document the following information in the Company's customer information system (e.g., DIS, CIS).

a. Date and time access denied.

b. Name and title of emergency services individual (e.g., Bob Smith, Lieutenant).

c. Local emergency services department name (e.g., Portsmouth Fire Department).

3. STRONG ODOR OF GAS AND/OR INDICATION OF GAS ON A COMBUSTIBLE GAS INDICATOR (CGI)

The condition shall be considered hazardous when performing a gas leak or odor investigation and a leak is identifiable by one or more of the following indications.

a. A strong odor or soundof gas.

b. A CGI indicates a gas reading of 2% LEL (i.e., 0.1% gas, 1000 ppm) or greater in the free air (unconfined area) of any room in a residence, apartment, or commercial building.

c. Any indication of gas which has migrated into or under a building.

3.1 Immediate Actions

The following actions shall be taken immediately, in an order appropriate to the particular situation.

a. Evacuate occupants from the affected area and establish a perimeter around the affected area, into which unauthorized persons are not permitted to enter.

b. Prohibit smoking, use of anything that could make a spark or flame, turning on or off any motorized and/or electrical equipment, including but not limited to: garage door openers, lights, fire alarms, intercom systems, appliances, personal electronic devices, etc. or raising/lowering of windows and use of a telephone, etc., to prevent the possible ignition of gas in the area.

c. Turn off the gas at an outside location, if it can be done safely. The choice of where to turn off the gas depends on the situation. If the building is served by an individual service line and meter, turn the gas off at the curb valve or meter valve. In a building with a common service line serving multiple units or sections, and the odor is confined to only one unit or section of the building, the gas shall be turned off to that unit or section, if it can be done safely at an outside location. Otherwise, turn gas off at the curb (if one exists) or meter valve, if it can be done safely at an outside location.

d. If leakage is detected entering the building from an outside source, the investigation shall immediately extend to the outside area around the building. Refer to GS 1708.070 “Outside Leak Investigation.”

NOTE: When the suspected source is from the outside and the outside leak investigation has been completed, continue with the inside investigation.

e. Notify the Integration/Work Management Center or designee to contact emergency services and the electric and telephone companies to shut off service. Work with the other utilities to shut off service in a non-gaseous area so there is no possibility of igniting gas.

f. Verify that the situation has been “made safe.”

3.2 Follow-up Actions

The following actions shall be taken to verify the source of the leakage and to re-establish gas service.

a. Use a CGI at openings in basement walls (e.g., cinder block openings), floor drains and utility service entrances. Also, use a gas detector or leak detection fluid at all meters. If the structure is one apartment unit of a multiple dwelling or one section of a commercial building, use the gas detector at all openings that may be a source of odor from other parts of the building. If indication of gas is found, continue investigation until the source is located. Follow guidance within this gas standard or within GS 1708.070 “Outside Leak Investigation,” as appropriate.

b. The affected customer's house lines and service lines, equipped with a curb valve, shall be pressure drop tested. If no curb valve exists, conduct a Surface Gas Detection Survey of the service line. If the Surface Gas Detection Survey of the service line indicates leakage on the service line, perform a Subsurface Gas Detection Survey (e.g., CGI inspection) in accordance with GS 1708.055 “Performing Barholing.”

c. If it has been determined that the odor is from natural gas and its source has not been definitely located by any of the above procedures, all piping (house and service lines) shall be subjected to a pressure test regardless of the number of units, sections of the building or the valving arrangement.

d. If a pressure test of the house and service line indicates no leakage, a charcoal filter or equivalent shall be used on the gas detector to differentiate between natural gas and petroleum vapors such as, gasoline, cleaning fluid, etc. If odor or leakage is natural gas, continue to investigate until the source is located. If necessary, additional help shall be called to locate the source of the leakage. If the source of the leakage is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 “Investigation of Gas Indication from an Unknown Source” and Systems Operations will continue the investigation in accordance with GS 1714.040 “Gas Sampling.”

e. Do not reestablish gas service until there is no indication of gas inside the building at all levels of the building.

4. NO ODOR OR FAINT ODOR OF GAS AND INDICATION OF GAS LESS THAN 2% LEL ON A COMBUSTIBLE GAS INDICATOR

When there is no odor or a faint odor of gas and the CGI shows an indication of gas less than 2% LEL (i.e., 0.1% gas, 1000 ppm) in the free air of any room of the affected area, proceed with the investigation as follows.

a. Obtain the customer's statement.

1. Determine if the customer notices odor only when an appliance burner is on.
2. Determine when the customer first noticed the odor.
3. Refrain from making conclusions until the investigation is completed.

b. Determine and eliminate all sources of the odor.

1. If the source is from pilot outage or combustion, and can be eliminated by lighting or making necessary adjustments, proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."
2. If the source is caused by a defective or improper vent, turn off all appliances connected to this vent and attach a red tag to each of the appliances (refer to the applicable GS 6500.010 “Use of Red Tag on Appliances”). If the source is a defective appliance, turn off gas supply to the appliance and attach a red tag. Proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."
3. If the source is from leakage at a valve or threaded connection, or an appliance connector, eliminate the leak by repairing or turning off the gas supply to the affected area or meter.

   If repairs are made:

   i. Use leak detection fluid and/or gas detector to verify that the leak is eliminated.

   ii. If it was necessary to turn off gas to house lines to repair the leak, the house lines shall be tested in accordance with GS 6500.050 or GS 6500.050(OH) “Methods for Testing Customer Service Lines and/or House Lines.”

   iii. After the leakage has been eliminated, proceed with Sections 5 "Complete the Inside Investigation," 6 "Inform Customer of Findings" and 7 "Records."

4. If the source of odor is not definitely located by (1), (2) or (3) above, the lines shall be tested as follows.

   i. Pressure test (e.g., drop test, dial test) the house lines. For buildings with a common service line serving multiple units or separate sections, test the house lines to the affected unit or section. If the affected unit or section cannot be isolated, test all house lines.

   ii. The service line shall be pressure tested or tested by the Surface Gas Detection Survey. If the Surface Gas Detection Survey of the service line indicates leakage on the service line, perform a Subsurface Gas Detection Survey (e.g., CGI inspection) in accordance with GS 1708.055 “Performing Barholing.”

   iii. If the Surface Gas Detection Survey does not indicate leakage on the service line, a CGI test in a barhole shall be made as follows (refer to GS 1708.055 "Performing Barholing" for additional guidance).

      For Outside Meters: Place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

      For Inside Meters: A visual observation of where the service line enters the foundation shall be made and measurements taken, so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

      Place the barhole at the foundation near to where the service line enters the building (e.g., 20” from suspected location of service line).

      If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

      Care shall be taken to minimize the risk of damaging the service line.

      For Buildings Without a Live Service Line: Place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

5. If it has been determined that the odor is from natural gas and its source has not been definitely located by any of the above procedures, all piping (house and service lines) shall be subjected to a pressure test regardless of the number of units, sections of the building or the valving arrangement. If the source of the leakage is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 "Investigation of Gas Indication from an Unknown Source" and Systems Operations will continue the investigation in accordance with GS 1714.040 "Gas Sampling."

5. COMPLETE THE INSIDE INVESTIGATION

a. If it is safe to do so, ventilate the area to eliminate any residual odor.

b. Use a CGI at openings in basement walls (e.g., cinder block openings), floor drains and utility service entrances. Also, use a gas detector or leak detection fluid at all meters. If the structure is one apartment unit of a multiple dwelling or one section of a commercial building, use the gas detector at all openings that may be a source of odor from other parts of the building. If an indication of gas is found, continue investigation until the source is located. Follow guidance within this gas standard or in GS 1708.070 "Outside Leak Investigation," as appropriate.

6. INFORM CUSTOMER OF FINDINGS

Provide the customer with the information below. If the customer is not home, leave a door hanger or knob card with the following information.

a. Explain the problem that was found and any corrective action taken.

b. Inform the customer of any leakage, incorrect venting or defective appliance which must be corrected.

c. Instruct the customer to call the Company if the odor is detected again.

7. RECORDS

Record the following on the Company's customer information system (e.g., DIS, CIS).

a. Arrival time.

b. Customer's description of the odor (if different from order instructions).

c. Conditions found (e.g., description of findings, carbon monoxide (CO) readings if found).

d. Test results (e.g., house line leakage, no leakage found on Company facilities).

e. Actions taken (e.g., gas supply to specific appliance(s) shut off, red tagged - what and why).

f. Recommendations made to the customer.

g. Other pertinent information.

Follow the applicable GS 6500.010 “Use of Red Tag on Appliances” for guidance regarding documenting red tag condition(s).

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Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE None

1. GENERAL

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

For additional information when responding to a natural gas emergency, refer to GS Series 1150 “Emergency Response” Standards.

Leak investigations shall be performed by qualified personnel. Classify leaks found in accordance with the applicable GS 1714.010 “Leakage Classification and Response.”

This gas standard is intended to be used when performing work as a qualified first responder to a potential natural gas emergency, regardless of job title.

All barholes shall be made in accordance with GS 1708.055 "Performing Barholing."

For the purposes of this gas standard, when the phrase “building foundation,” “foundation wall,” or “foundation” is used, it includes mobile home skirting.

2. DEFINITIONS

“Surface Gas Detection Survey” is a continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to aboveground gas facilities using an instrument approved for this type of survey on the appropriate sensitivity scale.

“Subsurface Gas Detection Survey” is the sampling of the subsurface atmosphere through barholes and/or available openings with a combustible gas indicator (CGI).

“Establish the leakage perimeter” is the process of creating a boundary of the leakage area. The leakage perimeter consists of subsurface inspection locations that can be monitored for changes in CGI readings, and includes inside inspection results, if applicable. The leakage perimeter is established when 0% gas is obtained in two consecutive subsurface inspections (e.g., barholes, available openings). Refer to Section 4.2 for guidance on establishing the leakage perimeter.

“Suspected leakage area” is defined as (1) the reported odor, emergency, or priority at a specific address or location, (2) leakage found during a programmed leakage survey, or (3) leakage found during an operations and maintenance (O&M) activity.

“6-pack” is a phrase used to give further guidance to determine the minimum amount of buildings included within the immediate vicinity in a congested area (e.g., narrow lots, city block). The “6-pack” includes (1) the building with gas against the foundation; (2) & (3) the buildings on each side of the building with gas against the foundation; and (4), (5), & (6) the buildings on the opposite side of the main(s) from the first three buildings. See Exhibit A, Example 1, for an illustration of the “6-pack.”

“Made Safe” means that adequate precautionary measures were completed. “Adequate precautionary measures” is defined as action(s) taken to reasonably ensure the public’s safety, which shall be validated by ensuring that the action(s) taken resulted in the gas dissipating and the situation is non-hazardous.

3. GENERAL ACTIONS DURING A NATURAL GAS EMERGENCY

Protecting life and property shall always take precedence and dictate the actions to be taken during a natural gas emergency.

A hazardous leak (i.e., Grade 1) 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 actions, in an order appropriate to the conditions encountered. Often, emergency services can assist in a natural gas emergency.

a. Evacuate premises, as necessary.

b. Eliminate sources of ignition.

c. As soon as safety permits, notify the Integration/Work Management Center of the actions required which may include contacting the following.
    1. Property owner.
    2. Emergency services (e.g., Fire, Police) to gain access to involved structure.
    3. Local leadership.
    4. Electric and telephone companies to shut off service. Work with the other utilities to shut off service in a non-gaseous area so there is no possibility of igniting gas.
    5. Request for additional field employees.

d. Shut off the gas by the safest and fastest possible means if there is a threat to life or property.

e. Vent the leakage area, if practicable, by removing manhole covers, barholing, installing vent holes, or other means.

f. Keep all bystanders away from hazardous areas.

g. Stop or reroute vehicular traffic where large volumes of escaping gas are present.

h. When gas facilities are damaged and there is a release of gas, investigate adjacent building(s) and building(s) directly across the street since hazardous conditions may exist. In addition, an investigation must be conducted to determine if secondary damage has occurred.

If the hazardous gas leak (i.e., Grade 1) can be immediately repaired, do so, and then notify the Integration/Work Management Center (dispatcher) of the actions taken.

Complete applicable records in accordance with Section 5.

4. PERFORM OUTSIDE LEAK INVESTIGATION

Obtain information about the suspected leakage area. If this situation is a reported odor call, attempt to talk to the person who made the report.

NOTE: The investigation may need to extend to the inside for a free air CGI reading. A positive reading may be an indication that gas is migrating into the building, secondary damage has occurred, or the odor is coming from the inside.

Turn on the leak detection instrument (e.g., multi-purpose CGI, FI, IR) in the outside free air; set scale on the appropriate scale for the investigation to be conducted (i.e., % LEL, % gas, monitor mode); and zero the instrument before proceeding into the suspected leakage area.

The suspected leakage area to be checked is determined by existing conditions such as frost, hills, conduits, sewers, drain lines, density of buildings, etc.

NOTE: The effectiveness of the Surface Gas Detection Survey may be inhibited by frost, snow, saturated soil, and/or hard surface conditions. However, a Surface Gas Detection Survey over the suspected leakage area set on the appropriate scale (e.g., ppm) may detect gas through cracks or voids, thereby providing an initial leakage perimeter to assist in the positioning of barholes. If the Surface Gas Detection Survey does not produce results due to inhibiting surface conditions, then proceed with the Subsurface Gas Detection Survey (Section 4.2).

Establish an initial leakage perimeter of the suspected leakage area using a Surface Gas Detection Survey (Section 4.1), and then as directed by the results of the Surface Gas Detection Survey, and if a gas indication is found, continue to establish the leakage perimeter by using the Subsurface Gas Detection Survey (Section 4.2). One exception is a facility damage with a release of gas, which in this case may proceed directly to the

Subsurface Gas Detection Survey (Section 4.2).

Refer to GS 1708.030 “Leakage Survey and Test Methods” and GS 1708.055 “Performing Barholing” for additional guidance.

4.1 Surface Gas Detection Survey

The Surface Gas Detection Survey can often be used to establish an initial perimeter of the leakage migration.

Start a Surface Gas Detection Survey by using an instrument approved for this type of survey on the appropriate sensitivity scale to determine the initial leakage perimeter.

The investigation originates with the suspected leakage area. Considerations for establishing the leakage perimeter must include geographic conditions (e.g., terrain) and physical attributes (e.g., driveways, pavement, frost), which affect the migration of gas.

NOTE: The highest instrument readings may be located remotely from the actual leak due to geographic conditions and physical attributes.

If possible, contact the person who placed the call to determine the location and nature of the reported leak.

4.1.1 Areas to Survey

Determine if a suspected leak exists by surveying the following areas, as applicable.

NOTE: Any potential leak found that is suspected to be hazardous (i.e., Grade 1), respond with appropriate actions in accordance with Section 3.

a. Foundation wall(s), including the service entrance and the meter set assembly.

b. Foundation wall(s) of any building(s) in the immediate vicinity, including the service entrance and the meter set assembly.

c. Cracks in the pavement in streets and sidewalks and any other area where gas could escape from the ground.

d. Substructures, such as electric, telephone, and sewer systems. When opening manhole covers, crack the cover to take initial readings. Be aware that manhole seals may exist under the manhole cover and may have to be removed in order to perform subsurface gas detection test.

e. Service line(s). Refer to the applicable GS 1708.020 “Leakage

Surveys" for acceptable leakage survey patterns for service lines.

f. Main(s). Refer to available records for the general location.

g. Structure(s) appearing to be vacant or unoccupied.

4.1.2 Responses to the Surface Gas Detection Survey

Any potential leak found that is suspected to be hazardous (i.e., Grade 1), respond with appropriate actions in accordance with Section 3.

Additional actions to take if gas indication is found (the following is to be performed in an order appropriate to the particular situation).

Indication of Gas at Building Foundation

a. Verify that gas is present by performing a subsurface gas detection test with a barhole.

   i. At a building with an outside meter, place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

   ii. At a building with an inside meter(s) and where access can be gained, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth of the gas facility can be ascertained prior to barholing.

   Place the barhole at the foundation near to where the service line enters the building (refer to GS 1708.055 "Performing Barholing").

   If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

   Care shall be taken to minimize the risk of damaging the service line.

   iii. Where indications are found at building(s) without a live service line(s), place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

b. If gas is present at the building foundation, extend the investigation to the inside and refer to GS 1708.060 “Inside Leak Investigation.”

c. If gas is not present at the building foundation, continue to establish the initial perimeter using the Surface Gas Detection Survey.

Indication of Gas in Substructure (with Conduit that Provides a Means of Entrance into a Building)

a. When there is an indication of gas in a substructure(s) with a conduit(s) that provide a means of entrance into a building (e.g., sanitary sewer, telephone ducts), verify with a CGI that gas is present.

b. If gas is present, perform an inside leak investigation (refer to GS 1708.060 "Inside Leak Investigation") in the building(s) in the area adjacent to readings in the substructure(s) because of possible migration into building(s).

c. Continue checking substructures with a CGI in both directions until no gas readings are present.

d. If gas is not present, continue to establish the initial perimeter using the Surface Gas Detection Survey.

Other Indications of Gas

a. If an indication of gas is found and is suspected to be hazardous, respond with appropriate actions in accordance with Section 3.

b. If an indication of gas is found, but is not suspected to be hazardous, continue establishing the initial perimeter with the Surface Gas Detection Survey.

Once the initial perimeter is established, proceed with the Subsurface Gas Detection Survey guidance in Section 4.2.

No Indication of Gas on Surface Gas Detection Survey Equipment

a. If leakage is not detected, but a gas odor is present, extend the investigation into building(s) in the vicinity of the suspected leakage area by performing an inside leak investigation (refer to GS 1708.060 “Inside Leak Investigation”).

b. If an odor of gas is present and cannot be located via the Surface Gas Detection Survey or the inside leak investigation, proceed to the Subsurface Gas Detection Survey (Section 4.2).

c. If leakage is not detected and there is no gas odor, perform a subsurface gas detection test(s) with a barhole(s) at building(s) in the vicinity of the suspected leakage area shall be conducted as follows.

i. Where the suspected leakage area involves outside meter(s), place the barhole between the service riser and the foundation wall. Care shall be taken to minimize the risk of damaging the service line.

ii. Where the suspected leakage area involves inside meter(s), and where access can be gained, a visual observation of where the service line enters the foundation shall be made and measurements taken so that the entry point and approximate depth can be ascertained prior to barholing.

Place the barhole at the foundation near to where the service line enters the building (refer to GS 1708.055 “Performing Barholing”).

If inside access cannot be gained, attempt to locate the gas facility using an approved pipe locator. If locating facilities with an approved locator is unsuccessful, refer to pipeline records and maps that are available in the field for facility locations prior to barholing.

Care shall be taken to minimize the risk of damaging the service line.

iii. Where the suspected leakage area involves building(s) without a live service line(s), place barhole(s) at the foundation. Consider location of other utilities to avoid damages.

iv. If no building(s) are located in the suspected leakage area, a Subsurface Gas Detection Survey is not required and the outside investigation order may be completed.

d. Complete all necessary documentation as required in Section 5.

4.2 Subsurface Gas Detection Survey

Once the leakage results are known from the Surface Gas Detection Survey used in Section 4.1, the initial leakage perimeter can be more precisely defined by performing a Subsurface Gas Detection Survey.

NOTE: Any leak classified as a Grade 1, respond with appropriate actions in accordance with Section 3.

Considerations for establishing the leakage perimeter must include geographic conditions (e.g., terrain) and physical attributes (e.g., driveways, pavement, frost), which affects the migration of gas.

NOTE: The highest CGI readings may be located remotely from the actual leak due to geographic conditions and physical attributes.

Establish the leakage perimeter by the following actions.

a. Obtain instrument readings in directions extending outward surrounding the leakage area. The leakage perimeter is established when 0% gas is obtained in two consecutive subsurface inspections (e.g., barhole, available openings in substructures). Consider inside inspection results, if applicable.

NOTE: In a Grade 1 condition, the leakage perimeter, as well as the leakage area within the perimeter, shall be monitored on an ongoing basis until the situation is made safe, or turned over to the responsible party (e.g., non-Company gas). More guidance on monitoring is found in Section 5 of this gas standard.

Mark barholes and other monitoring locations in accordance with Exhibit A.

b. If the leak investigation shows that gas is present at a building foundation, the investigation shall be extended to the inside of the building. Refer to GS 1708.060 "Inside Leak Investigation."

Also, continue establishing the leakage perimeter as required in Section 4.2.a. above. Once the leakage perimeter has been established, the leak investigation shall be extended to building(s) in the immediate vicinity by means of either the Surface Gas Detection Survey or the Subsurface Gas Detection Survey.

NOTE: If foundation(s) are inaccessible (e.g., fence), check as close as practicable. If gas is migrating towards the inaccessible building, access shall be gained (i.e., contact emergency services).

In a congested area where buildings are in close proximity to each other (e.g., narrow lots, city block), the immediate vicinity includes, at a minimum, the "6-pack" of buildings. If gas is found against other building foundation(s) of the original "6-pack," then the "6-pack" becomes a dynamic "6-pack" and is extended until no gas is found.

For areas that are less congested (e.g., suburban, semi-rural), the inclusion of additional buildings will be dependent upon geographic conditions (e.g., terrain), physical attributes (e.g., driveways, pavement, frost), and the migration of gas.

In a rural area (e.g., agricultural areas, homes on country lots), where buildings are spread out with hundreds of feet between them, the immediate vicinity may include no additional buildings.

c. If the source of the leak is suspected to be from a foreign company or stray gas, continue to monitor as if it is a leak on Company facilities. Field Operations will continue the investigation in accordance with GS 1708.080 "Investigation of Gas Indication from an Unknown Source" and Systems Operations will continue the investigation in accordance with GS 1714.040 "Leakage - Sampling of Unknown/Stray Gas."

Refer to Exhibit A for additional guidance. Examples 1 and 2 in Exhibit A are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

5. MONITOR LEAKAGE PERIMETER AND LEAKAGE AREA

The monitoring of the leakage perimeter, as well as the leakage area within the perimeter, is to be conducted continuously during Grade 1 conditions to document any changes to the leakage area and to ensure that the leakage migration does not extend beyond the original established leakage perimeter. The leakage perimeter shall be adjusted if necessary, throughout the investigation, until the condition is made safe.

NOTE: The use of additional barholes is recommended to validate that the leakage perimeter has not changed. As work is being done, the leakage perimeter may grow or shift as actions are taken.

Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” (Exhibit B), or equivalent documentation, shall be used to document results of monitoring the leakage perimeter, as well as the leakage area within the perimeter, for below ground Grade 1 conditions.

See Exhibit B for an example showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.”

6. RECORDS

Document the following information on the Company’s customer information system (e.g., DIS, CIS) and/or work management system.

a. Name of investigator.

b. Arrival and departure times.

c. Test results.

d. Conditions found.

e. Actions taken.

f. Any other pertinent information necessary to complete the work order.

In addition, confirmed outside leaks on jurisdictional facilities are documented on Form GS 1708.100-1 “Distribution Plant Inspection and Leak Repair” (DPI or leak order), with the exception of non-hazardous leaks (i.e., Grade 2+, 2 or 3 classified leaks) on outside meter set assemblies. Refer to GS 1708.100 “Leakage Control Records” for additional information.

When used, Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” shall be filed with the associated DPI form(s).

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EXHIBIT A
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GUIDELINES FOR ESTABLISHING A LEAKAGE PERIMETER

Examples 1 and 2 are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

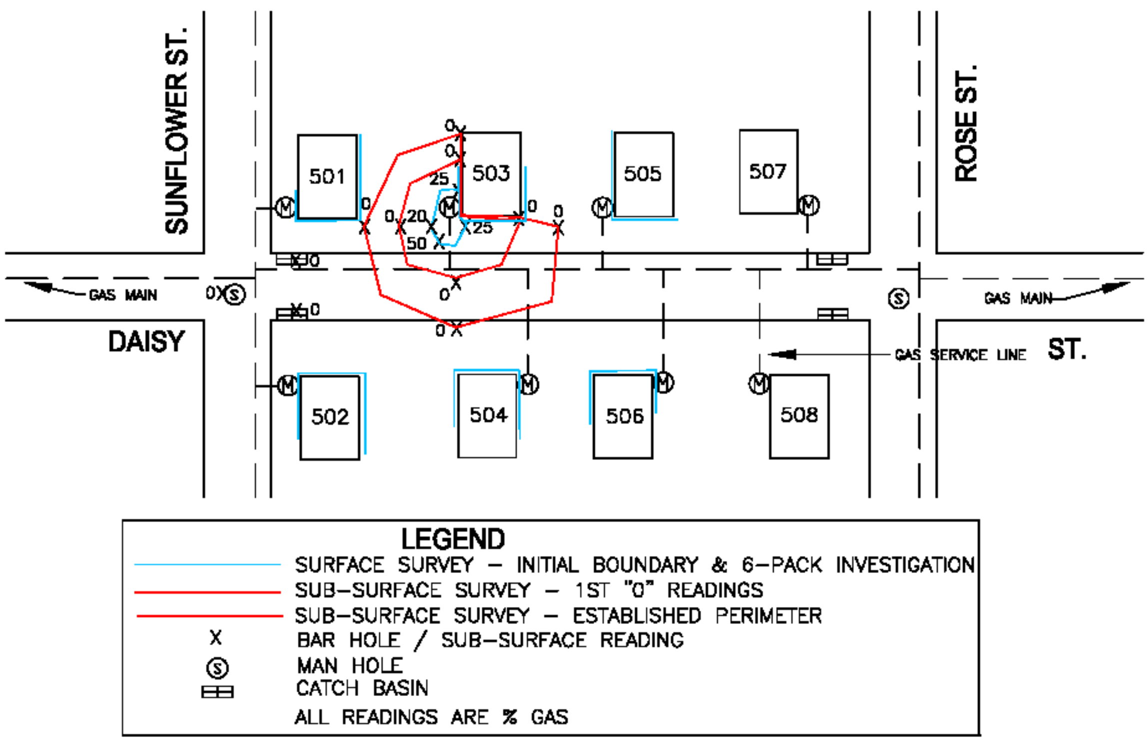
Example 1: Generic Residential Area

A first responder is dispatched to 503 Daisy St. to perform an outside leak investigation. Once initial perimeter of the leakage area is determined with the Surface Gas Detection Survey (Section 4.1), proceed with a Subsurface Gas Detection Survey (Section 4.2) using a CGI and barholes to establish the leakage perimeter.

- Sample barholes in directions extending outward surrounding the leakage area.
- The leakage perimeter is established when results indicate 0% gas in consecutive barholes.
- In this example, gas is verified at the foundation of 503 Daisy St. (25% gas – Grade 1 leak). Since gas is present against the foundation of 503 Daisy St., an inside leak investigation is required. In this example, the inside leak investigation resulted in no gas indications inside of 503 Daisy St.
- Because gas is present at a foundation, the investigation is required to be extended to the buildings in the immediate vicinity (i.e. 6-pack) at buildings at 501, 505, 502, 504, & 506 Daisy St.
- The investigation of the 6-pack is done via the Surface Gas Detection Survey. In this example, the results of Surface Gas Detection Survey of the 6-pack show no gas indications at the foundations of these buildings.
-
- The perimeter has been established.

    NOTE: This example depicts a Grade 1 leak, and in accordance with Section 5, the leakage perimeter is required to be monitored until the situation is made safe.

The example below is for illustration purposes only. Establishing a leakage perimeter is contingent on the location of the gas facilities and the location of structures.



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GUIDELINES FOR ESTABLISHING A LEAKAGE PERIMETER
Examples 1 and 2 are for illustration purposes only. Conditions in the field will dictate if the area of investigation needs to be extended further.

Example 2: Mix-Zoned Area with Buildings Spaced Approximately 200 Feet or Greater Apart

A first responder is dispatched to 11100 U.S. Route 30 to perform an outside leak investigation. Once initial perimeter of the leakage area is determined with the Surface Gas Detection Survey (Section 4.1), proceed with a Subsurface Gas Detection Survey (Section 4.2) using a CGI and barholes to establish the leakage perimeter.

- Sample barholes in directions extending outward surrounding the leakage area.
- The leakage perimeter is established when results indicate 0% gas in consecutive barholes.
- In this example, gas is verified at the foundation of 11100 U.S. Route 30 (5% gas – Grade 1 leak). Since the consecutive 0% gas readings are in close proximity to the address 11100, and the other buildings are not in close proximity to the established leakage perimeter, the extension of the leakage perimeter to other buildings is not required.
  NOTE: Since gas is present against the foundation, an inside leak investigation is required.
- The perimeter has been established.
  NOTE: This example depicts a below ground Grade 1 leak, and in accordance with Section 5, the leakage perimeter is required to be monitored until the situation is made safe.

The example below is for illustration purposes only. Establishing a leakage perimeter is contingent on the location of the gas facilities and the location of structures.

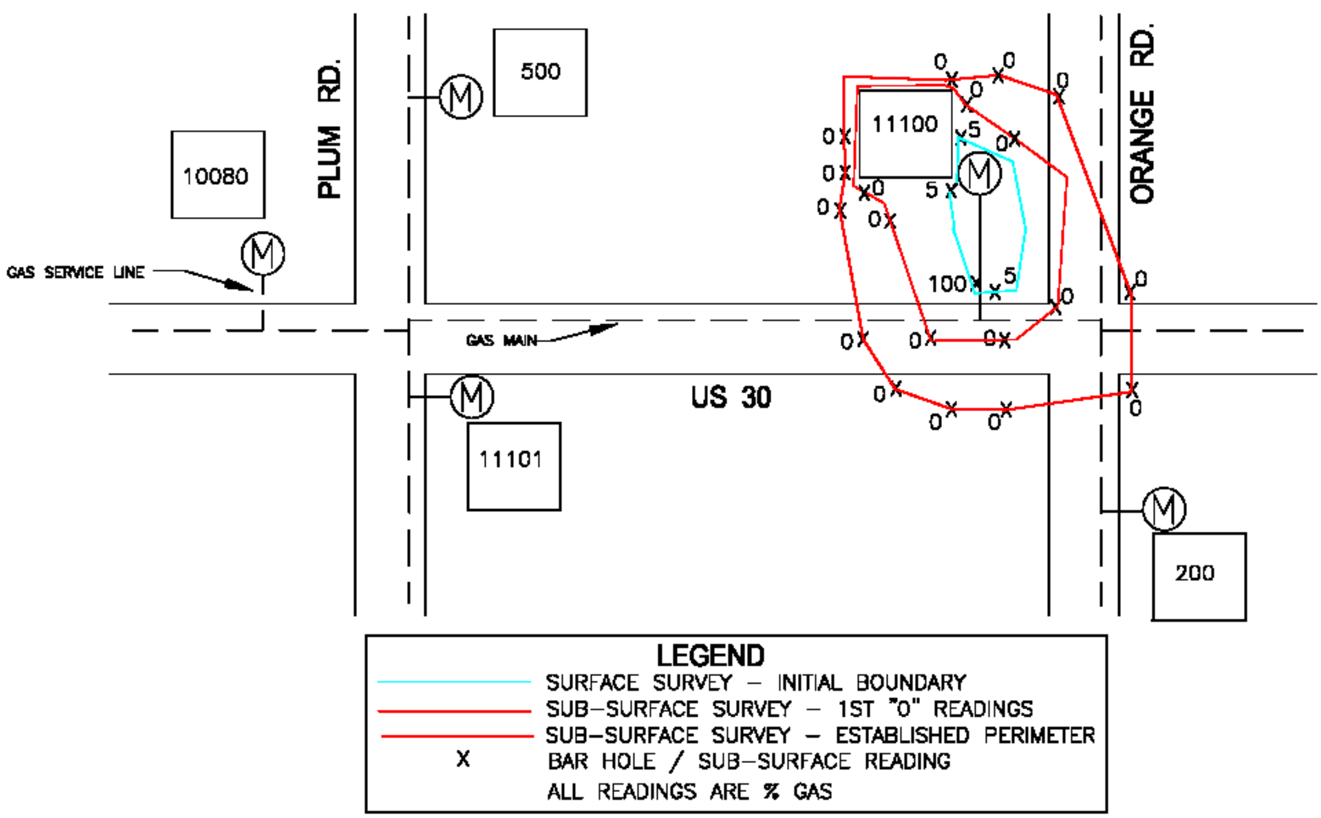

**EXHIBIT B
(1 of 10)**

Instructions for Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document”

Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document” is used to document the location, date, time, and instrument readings related to monitoring a leakage perimeter. Information related to the numbers on the Form GS 1708.070-1 “Leakage Perimeter Monitoring Document” shown in the figure below is described in the following section.

1. Cover Page – Date: Indicate the date of arrival on site for the leak investigation.

2. Cover Page – Time of Arrival: Indicate the time of arrival on site for the leak investigation. When time is recorded use the 24-hour clock system.

3. Cover Page - DPI, PSID, or Site ID: Indicate the DPI number from Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” or the site identification number (i.e., PSID or Site ID) from the customer information system (i.e., DIS or CIS) related to the leakage area being monitored.

4. Cover Page - J.O.#: Indicate the work management system (WMS) job order number related to the leakage area being monitored.

5. Cover Page - Address/Location: Indicate the address or description of the location of the leakage area.

6. Sketch - Sketch Area: Indicate the following items to help identify the leakage area and locations to be monitored.
   a. Buildings and addresses in the vicinity of the leakage area.
   b. Monitoring locations with an identifier (e.g., A, B, C).
   c. Existing buried facilities in and around the leakage area. Indicate the following, if known or appropriate:
      (1) Company mains – show size and approximate location.
      (2) Service lines – show location of service line(s) and curb box(es), if applicable.
      (3) Other facilities – show those facilities which could help identify the approximate area of the monitoring locations. Refer to “Legend” on the form, which provides symbols for manholes, utility poles, etc.

7. Sketch - Indicate North: Indicate north by marking an “N” near the appropriate line or other recognized symbols to indicate north may be used.

8. Sketch - Page ____ of ____: Indicate the current page of the documentation and the total pages included in the documentation.

9. Readings Pages - Employee Name/ID: Indicate the name and employee identification number of the person establishing and monitoring the leakage perimeter.

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10. Readings Pages - Date: Indicate the date that the leakage perimeter was established and monitoring began.

11. Readings Pages – Time: Indicate the time that the leakage perimeter was established and monitoring began. When time is recorded use the 24-hour clock system.

12. Readings Pages - Instrument Serial#: Indicate the manufacturer's serial number or Company tag number of instrument used to take gas readings at the monitoring locations.

13. Readings Pages - DPI or PSID#: Indicate the DPI number from Form GS 1708.100-1 "Distribution Plant Inspection and Leakage Repair" or the customer identification number from the customer information system (i.e., DIS or CIS) related to the leakage area being monitored.

14. Readings Pages - J.O.#: Indicate the work management system (WMS) job order number related to the leakage area being monitored.

15. Readings Pages - Address/Location: Indicate the address or description of the location of the leakage area.

16. Readings Pages - Date: Indicate the date that the row of readings was taken at the designated locations to monitor the leakage perimeter.

17. Readings Pages - Time: Indicate the time that the reading was taken at the location designated with the letter "A." When time is recorded use the 24-hour clock system.

18. Readings Pages - A - % Gas or LEL: Indicate the gas reading at location "A" and the scale of that reading (e.g., 0% Gas). Continue documenting gas readings at locations "B," "C," "D," etc. until each designated location has been monitored.

19. Readings Pages - Receiving Employee Name/ID: Indicate the name and the employee identification number of the person taking over monitoring the leakage perimeter, if applicable.

20. Readings Pages - Date: Indicate the date that the person identified in Key 13 took over monitoring the leakage perimeter, if applicable.

21. Readings Pages - Time: Indicate the time that the person identified in Key 13 took over monitoring the leakage perimeter, if applicable. When time is recorded use the 24-hour clock system.

22. Readings Pages - Instrument Serial#: Indicate the manufacturer's serial number or Company tag number of the instrument used by the person identified in Key 13 to continue monitoring the perimeter, if applicable.

23. Readings Pages - Page ____ of ____: Indicate the current page of the documentation and the total pages included in the documentation.

**EXHIBIT B
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LEAKAGE PERIMETER/AREA MONITORING DOCUMENT

Date: 1 ______________ Time of Arrival: 2 _____________

DPI, PSID or Site ID: 3 ______________________________ J.O.#: 4 ____

Address/Location: 5 ____

Form GS 1708.070-1(02/2014)

Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Outside Leak Investigation	Standard Number: GS 1708.070
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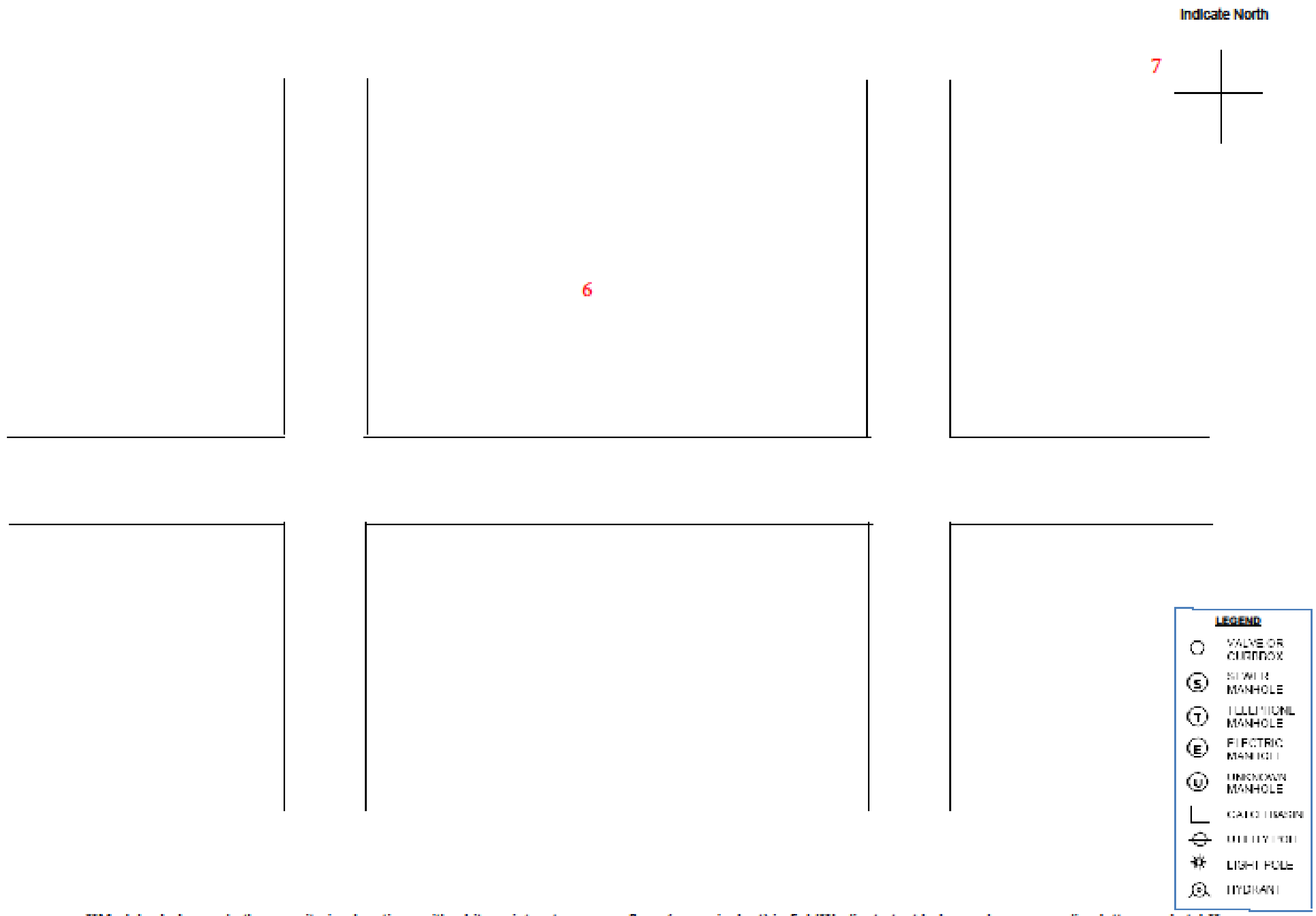

"Mark barholes and other monitoring locations with white paint or temporary flags (or equivalent) in field""Indicate test holes and corresponding letter on sketch""
""Indicate buildings and addresses on sketch""

Page ____ of ____ 8

Form GS 1708.070-1 (02/2014)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Outside Leak Investigation	Standard Number: GS 1708.070
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Leakage Perimeter/Area Monitoring Document

Employee Name/ID: 9 Date: 10 Time of Arrival: 11 Instrument Serial#: 12

DPI, PSID or Site ID: 13 J.O.#: 14 Address/Location: 15

		A	B	C	D	E	F	G	H	I	J	K	L	M
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
16	17	18												

Monitor Change:
Receiving Employee Name/ID: 19 Date: 20 Time: 21 Instrument Serial#: 22

Receiving Employee Name/ID: ____ Date: ____ Time: ____ Instrument Serial#: ____

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The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 "Leakage Perimeter/Area Monitoring Document."

LEAKAGE PERIMETER/AREA MONITORING DOCUMENT

Date: 1/1/2014 Time of Arrival: 17:10

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00

Address/Location: 3 Jones Ave., Mtown, State

Form GS 1708.070-1(02/2014)

NiSource
Distribution Operations

Gas Standard

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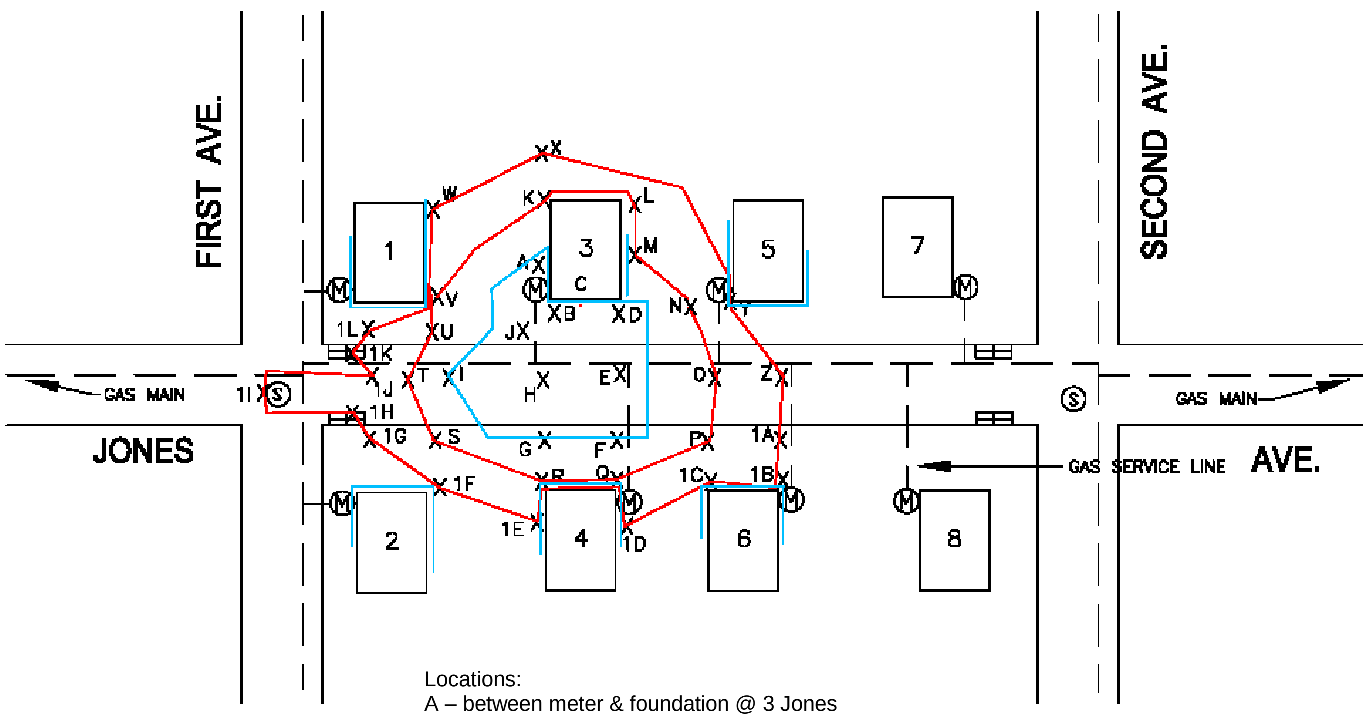
The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)



Locations:
A – between meter & foundation @ 3 Jones
B – at SW corner of 3 Jones
C – inside 3 Jones
H – near tap for 3 Jones
J – in curb box for 3 Jones

Mark barholes and other monitoring locations with white paint or temporary flags (or equivalent) in field Indicate test holes and corresponding letter on sketch**
Indicate buildings and addresses on sketch
Page _1_ of _4_

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Gas Standard

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The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		A	B	C	D	E	F	G	H	I	J	K	L	M
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:35	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:50	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:04	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:18	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:32	25% Gas	25% Gas	0% LEL	10% Gas	20% Gas	5% Gas	5% Gas	60% Gas	5% Gas	50% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:46	22% Gas	23% Gas	0% LEL	8% Gas	18% Gas	5% Gas	5% Gas	30% Gas	5% Gas	25% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:00	18% Gas	18% Gas	0% LEL	5% Gas	10% Gas	3% Gas	3% Gas	0% Gas	2% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:14	10% Gas	10% Gas	0% LEL	0% Gas	5% Gas	1% Gas	0% Gas	0% Gas	1% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:29	5% Gas	7% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:42	0% Gas	0% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:56	0% Gas	0% Gas	0% LEL	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas

Monitor Change:
Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

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NiSource
Distribution Operations

Gas Standard

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(9 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 “Leakage Perimeter/Area Monitoring Document.” (continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		N	O	P	Q	R	S	T	U	V	W	X	Y	Z
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:35	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	17:50	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:04	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:18	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:32	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	18:46	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:00	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:14	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:29	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:42	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas
1/1/2014	19:56	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas

Monitor Change:
Receiving Employee Name/ID: ______ Date: ______ Time: ______ Instrument Serial#: ______

Receiving Employee Name/ID: ______ Date: ______ Time: ______ Instrument Serial#: ______

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(10 of 10)

The following is an example, for illustration purposes only, showing the use of Form GS 1708.070-1 "Leakage Perimeter/Area Monitoring Document."(continued)

Leakage Perimeter Monitoring Document

Employee Name/ID: Joe Smith - 499999 Date: 1/1/14 Time of Arrival: 17:10 Instrument Serial#: 246897531

DPI, PSID or Site ID: C975312 J.O.#: 14-1234567-00 Address/Location: 3 Jones Ave., Mtown, State

		1A	1B	1C	1D	1E	1F	1G	1H	1I	1J	1K	1L	~~M~~
Date:	Time:	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL	% Gas or LEL
1/1/2014	17:15	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	17:35	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	17:50	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:04	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:18	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:32	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	18:46	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:00	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:14	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:29	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:42	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	
1/1/2014	19:56	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	0% Gas	

Monitor Change:

Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

Receiving Employee Name/ID: ______________________ Date: __________ Time: ________ Instrument Serial#: ______________

Page 4 of 4 Form GS 1708.070-1 (02/2014)

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2013	**Investigation of Gas Indication from an Unknown Source**	Standard Number: **GS 1708.080**
Supersedes: 01/01/2012		Page 1 of 4

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

When an odor or gas indication is detected and/or reported through Company surveys or outside sources, the Company's primary obligation is to evaluate conditions and initiate corrective action(s) to make the area safe.

The affected pipeline facilities, whether Company or customer owned, shall be inspected in an attempt to find the source of the gas indication (see GS 1708.030 "Leakage Survey and Test Methods"). Normal operating procedures are followed if leakage is found on either the Company's or the customer's facilities.

If inspection of the Company's and customer's facilities in the area indicates that the source of the positive combustible gas indication is not from those facilities or that the source of a gas odor remains unknown, an investigation for the unknown gas shall be instituted in accordance with this standard.

2. HAZARDOUS CONDITIONS

When a hazardous condition exists, action shall be taken to protect life and property. This action may include but is not limited to such things as evacuation of buildings, excavation for venting purposes, purging and elimination of ignition sources. (Refer to the Company's Emergency Plan for further guidance.) In addition monitoring of the gas facilities in the area shall continue until results of gas sampling are received.

If the efforts to eliminate the gas against or within the structure are unsuccessful, the occupant should be advised and if the structure is served by gas, service will be terminated.

A public safety official should be advised of the actions that have been taken and of the fact that samples of gas are being collected for analyses.

3. TAKING GAS SAMPLES

Samples of gas from the unknown source and from Company facilities shall be taken, in accordance with GS 1714.040, "Gas Sampling." Samples of both gases are required to permit a comparison of the components to assist in determining the source of the unknown gas. Arrangements should be made to get the samples analyzed as quickly as possible.

4. INVESTIGATION/GAS SAMPLE ANALYSES

4.1 Company Gas or Non-Conclusive Results

If the investigation/analysis indicates the source is from the Company facilities, appropriate action to clear the leak should be taken.

If the investigation/analysis is non-conclusive, further investigation of the gas facilities beyond the area covered shall be made. Further investigation may include the following actions:

a. perform additional leakage surveys of adjacent properties, including bar testing,

b. contact local state agency to determine previous gas well or coal bed activities,

c. talk with local property owners about previous drilling activities,

d. patrol surrounding area for potential sources of stray gas, and/or

e. take additional gas samples for analysis.

4.2 Non-Company Gas

If the investigation/analysis indicates the source is from another pipeline operator, they shall be notified.

If the analysis indicates the gas is not pipeline gas, the appropriate state agency with jurisdiction over natural resources and/or a public safety official (usually the local fire chief), whichever is appropriate, shall be notified. If the unknown gas situation was reported by a third party, the party should be contacted and given an oral explanation of the findings and advised of the agency notified.

The existence of a potentially hazardous situation shall be communicated to a public safety official (usually the local fire chief) and a letter sent to confirm the original contact (see Exhibit A). A copy of the letter shall also be sent to the appropriate state agency. Caution must be exercised in composing the letters so that they state only the facts and not assumptions. All letters documenting potentially hazardous situations should be reviewed by the Legal Department before being provided to the authority. Gas sample analysis results are proprietary and should be released to the appropriate state agency only with permission of the Operations Center Manager.

Employees should be as helpful as possible to other agencies, but should keep in mind that the Company expertise is limited to the detection of leakage from the Company distribution system and its subsequent repair. The Company assumes no responsibility for abandoned gas wells, subsurface mines or for detecting origins of fermentation gas. If the city or other responsible agency needs professional assistance, they should be directed to the appropriate state agency. When in doubt, contact the Legal Department for assistance.

5. RESOLUTION OF POTENTIALLY HAZARDOUS STRAY GAS SITUATIONS

If gas sample result(s) indicate that the gas is not pipeline gas, or if the gas sample results are non-conclusive and a thorough investigation has determined that the source of the gas is from an unknown foreign source (or stray gas), a permanent venting system designed to prevent accumulation around the foundation or immediate perimeter of the structure or building, and direct gas away from potential ignition sources is an acceptable resolution.

If the gas sample result(s) and/or a thorough investigation confirms that the gas is not pipeline gas, the Company is not responsible for the design, installation, or monitoring of the permanent venting system.

6. RESTORING SERVICE TO CUSTOMERS

In the event that a customer or a third party requires/demands restoration of service to a premise where the Company has discontinued service due to stray gas against or entering the structure, the NiSource legal department must be contacted for guidance.

After such consultation, service may be restored only on signed, written orders from someone with authority over public safety. The person of authority should be the Mayor, Safety Director, Fire Chief, or similar authority, but not a fireman, secretary, or clerk. Also acceptable is a signed consent from an accredited engineering expert in the remediation of methane. The person of authority must be advised of and must acknowledge in writing, the responsibility they are accepting. In addition, the owner and occupant must be advised of the responsibilities they are accepting, and authorize in writing the restoration of service.

With approval from NiSource legal department, if a written order cannot be obtained, the restoration of gas service shall be dependent upon verification obtained from the authority having jurisdiction that the permanent venting system is properly operating.If during a surveillance program, a customer call or routine meter/ service work reveals the presence of gas in potentially hazardous quantities and/or locations, the investigation will be reopened as though no previous investigation had occurred at this location.

EXHIBIT A

(DATE)

SAMPLE

Fire Chief

City of Easternville

14 Main Street

Easternville, Ohio 12345

Dear Chief:

This letter is to confirm our previous telephone conversation of _(Date)_ of a situation in the vicinity of Elm and Porter Streets regarding the presence of gas from an unknown source.

During a routine leakage survey of the Company's natural gas facilities on _(Date)_, the presence of a combustible gas was detected. On further investigation, the perimeter of the combustible gas was found against the foundation of the residence at 148 Elm Street and the residence at 83 Porter Street. The customer's facilities, both service lines and house piping were tested and no leakage was found. Natural gas service to these two residences was discontinued and cannot be re-established until the condition is made safe.

Samples of natural gas from the Company's distribution system and the unknown gas were taken. The laboratory analyses indicate that the unknown gas is a natural gas with ratio of components different from the Company's gas. Since abandoned gas wells are known to be in the area, the source of this stray gas may be from such a well.

Records retained by the City or the State may assist you in locating and eliminating the unknown gas source.

If you have any questions concerning this matter, please feel free to contact me.

Very truly yours,

Operations Center Manager

cc: Dept. of Natural Resources

NiSource
Distribution Operations

Gas Standard

Effective Date: 06/01/2016	Leakage Control Records	Standard Number: GS 1708.100
Supersedes: 01/01/2015		Page 1 of 19

Companies Affected:

☐ NIPSCO	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

1. SURVEY RECORDS

A schedule shall be maintained of areas to be surveyed using the Repetitive Task (RT) feature in the Company's work management system (WMS).

To ensure that all facilities are being surveyed as required, the schedule shall be maintained in WMS. For each pipeline facility to be surveyed, the RT should include the following.

a. Operations map number.

b. Total footage to be surveyed.

c. Type of inspection area (e.g., business district, outside business district).

d. The frequency the area is to be surveyed (e.g., 12 months, 36 months, 60 months).

WMS will calculate the date each area is due to be inspected, and indicate the date the survey was last completed. WMS shall be used to record the completion of inspections.

Customer service lines surveyed individually or in conjunction with the main inspection program, except for those surveyed with the main under the same program, shall be recorded in accordance with Sections 2 or 3 of this standard.

The WMS schedule shall be reviewed and updated as necessary within each calendar year to correct business district or outside business district footages before beginning the next year's inspection schedule. Any update or changes made to the schedule shall require documentation of any variances from the previous inspection cycle, and shall be maintained through the next completed inspection cycle.

2. LEAKAGE RECORDS (DPI AND WMS)

2.1 Mains and Service Lines Up to Inlet of Meter Valve

Records of leakage found, repaired and cleared on mains and service lines up to the inlet of the meter valve (except for customer-owned service lines in Pennsylvania) shall be recorded both on Form GS 1708.100-1 "Distribution Plant Inspection and Leakage Repair" (DPI or leak order) and in WMS (See Exhibit A.) The form copies are to be used as follows:

Effective Date: 06/01/2016	Leakage Control Records	Standard Number: **GS 1708.100**
Supersedes: 01/01/2015		Page 2 of 19

Paper Original: Field working form while the leak is active, and shall be filed at the Operations Center when the leak is repaired and the DPI is closed. When possible, the paper original is to be filed and retained in the Main history file. Repair, replace and exposure data must be recorded on this copy or on a reproduction of the copy and attached. Applicable data on this form shall be recorded in WMS.

Paper Copy 1: Used as needed by Operations Center.

Paper Copy 2: Used as needed by Operations Center.

NOTE: (1) Re-inspection (re-evaluation). If there is a change in classification, the original leak order shall be cleared by reclassification and a new leak order written reflecting the new conditions. The two (2) leak orders shall be cross-referenced on the original copies and in WMS.

(2) Follow-up inspection. If during the follow-up inspection it is determined that leakage still exists, a new leak order shall be prepared and the two (2) orders cross-referenced on the original copies and in WMS.

(3) Scanned or tablet-originated copies are permissible when coordinating work between persons working in different locations, e.g. centralized support personnel or the Integration Center, as long as other requirements in this standard are met. Scanned copies shall be considered to be equivalent to paper copies.

An individual Main History File shall be maintained for each Distribution Company Transmission Main (refer to GS 1730.010 "Transmission Line Field Repair.")

2.2 Service Lines – Meter Set Assembly

For the purpose of this standard, the meter set assembly extends from the inlet of the meter valve to the connection of the customer's fuel line. The assembly includes components such as piping, fittings, meter and when required the service regulator.

2.2.1 Grade 1 Leaks

Form GS 1708.100-1 (Exhibit A) shall be completed for Grade 1 (hazardous) leaks associated with the meter set assembly. The use of Form GS 1708.100-1 shall follow the guidance contained in Section 2.1.

2.2.2 Non-Hazardous Leaks

Records of non-hazardous (i.e., Grade 2+, 2, & 3) leakage and repair on a meter set assembly shall be recorded on a WMS job order, job type 3811.

2.2.3 Customer-Owned Service Lines

For Pennsylvania, records of leakage and repairs on customer-owned/maintained service lines shall be recorded on a DIS order.

2.3 Maintaining Open Leak Orders

Each work location shall maintain open leak orders. Open leak orders shall be reviewed monthly to ensure that all leakage conditions are cleared or re-inspected in accordance with the requirements of GS 1714.010 "Leakage Classification and Response."

2.4 Filing and Retaining

Leak orders shall be filed and/or retained in accordance with the following schedules.

Clearance Code	Filing and/or Retention Schedule
21 and 22	If the leakage was cleared by main repair, the completed order shall be filed and retained for the life of the main but not less than ten years.
23 and 24	If the leakage was cleared by main replacement or abandonment, the completed order and any related main history records shall be retained for at least ten years from the cleared date.
25 and 26	If the leakage was cleared by Company service line repair, the completed order shall be filed and retained for the life of the service line. If the order contains information pertaining to the condition of both the service line and the associated main, the order shall be retained for the life of the service line or main, whichever is longer. In no case shall the order be retained for less than ten years from the date cleared.
27 and 28	If the leakage was cleared by Company service line replacement or abandonment, and the leak order contains information pertaining to the condition of the associated main, the completed order shall be retained for the life of the main. (Refer to GS 1410.010 "Metallic Pipeline Exposures.") In no case shall the order be retained for less than ten years from the date cleared.

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31 and 32 If determined that leakage is on another company's facility or a customer owned facility, the completed order shall be filed with the main history of the nearest main and retained for the life of that main.

If the order contains exposure information pertaining to the condition of a Company main and/or Company service line, the order shall be retained for the life of the facility.

NOTE: When a leakage condition is reported to an outside company, operator, or owner (including company affiliates), a notation of the method of notification (telephone, in-person, by copy of the leakage report), the name of the person notified, and the time and date of notification shall be noted in the "Remarks" section of the Company leak order file copy.

33 If the order was cleared by reinspection-negative (no leakage was found), the completed order shall be retained for at least ten years from the cleared date.

34 If the order is cleared by reclassification, the original order shall be attached to the new order and handled in the same manner as a new order.

35 and 44 If leakage was cleared by repair or replacement of a Plant Regulator, Plant Regulator Setting, or Plant Regulation Auxiliary Equipment, and the order contains inspection and/or exposure information pertaining to the condition of Plant Facilities (regulator and/or its appurtenances and piping), the order shall be retained for the life of the facilities described. The completed order shall be filed with the main history of the nearest main.

NOTE: Leak Orders pertaining to M&R Retail Sales Stations shall be filed and retained in the same manner as order pertaining to Plant Regulators.

36 and 45 If leakage was cleared by repair or replacement of a Meter Setting and/or Service Regulator(s) and leak order contains inspection information pertaining to the condition of pipeline facilities not replaced, the completed order shall be retained for the life of the pipeline.

37 and 38 If the leakage was cleared by customer service line repair in an area required to maintain customer service lines, the completed order shall be filed and retained for the life of the service line. If the order contains information pertaining to the condition of both the service line and the associated main, the order shall be retained for the life of the service line or main, whichever is longer. In no case shall the order be retained for less than ten years from the date cleared.

39 and 40	If the leakage was cleared by customer service line replacement or abandonment in an area required to maintain customer service line and the leak order contains information pertaining to the condition of the associated main, the completed order shall be retained for the life of the main. (Refer to GS 1410.010 "Metallic Pipeline Exposures.") In no case shall the order be retained for less than ten years from the date cleared.
41, 42 and 43	If the leakage was cleared by valve repair, the completed order shall be filed and retained for the life of the facility but not less than ten years.

3. DIS-SLDS RECORDS

The Customer Service Line Survey records are maintained by the Operations Center.

Reports of leaks shall be documented for verification. Leaks on customer-owned service lines (CPA only) should be recorded on a CS (DIS) order.

Leaks on company-owned buried customer service lines, up to the inlet of the meter valve, shall be recorded on a DPI in accordance with Section 2 of this standard.

3.1 Non-Synched Areas

An Operations Center that has not synched the main line and customer service line leakage inspections, shall request via DIS the “Leakage Inspection Schedule” by location (Exhibit B.)

CAUTION: Printing this schedule will delete any previously issued records for the file. Therefore, previously completed survey records must be posted prior to printing the schedule. Printing the schedule will no longer permit completed inspections to be reported by “Report No. – Page No.” for the prior reporting period.

After receiving the “Leakage Inspection Schedule,” the user needs only to bring up from the Report Request, Selection 3 “Leak Survey Record (Unit/Book/Inspection Year,” Exhibit C, to request survey records. The survey record selection may be made either by entering Unit/Book/Year or Unit/Book/All.

The customer Service Line Survey records requested will be sent to the Operations Center. These records will permit the Operations Center to commence its Customer Service Line Survey.

Upon completion of all or a portion of the survey, the file may be updated by selecting from the Service Line Menu “Change Inspection Date – Page No.” On this screen, the report number shall be entered and then the page number and new inspection date entered by location.

Changing the type of survey for a premise from a three-year survey to an annual survey or vice versa can be accomplished by making a “Keyword Change” on the SLDS.

3.2 Synched Area

Program Leak Survey schedules for Operations Centers that have synched the main line and customer service line leakage inspections are maintained in the WMS.

Leakage Survey areas are typically set up by map or GIS grid. Both main lines and customer service lines are inspected in the same cycle. Customer service line information, i.e. curb box location or meter location, may not be necessary due to Leakage Inspectors familiarity with the area. The “ED” report is furnished annually to assist in identifying customer service line information.

Documentation of the customer service line leakage inspection is the Leak Inspector’s completion of the WM job order.

4. FACILITY FAILURE REPORTS (FFR)

A Facility Failure Report (FFR) and subsequent failure investigation are required when leak orders are cleared with certain clearance codes. Please refer to GS 1652.010 “Investigation of Failures,” ON 13-03 “Facility Failure Reporting Process FAQs,” and Form GS 1708.100-1b “DPI/FFR Field Reference Guide,” for more guidance.

4.1 Required to Create FFR

A facility failure report shall be created if the leak location and location detail codes OR the leak cause code meet ANY of the conditions listed in Exhibit D of this Gas Standard.

Additionally, damages to Company facilities that result in pipe pull-out from mechanical fittings shall be reported as an FFR for the failure of the mechanical fitting.

4.2 May Require an FFR

A facility failure report may need to be created if the leak order clearance codes meet ANY of the following conditions. Either the leak cause code or the leak location code can trigger the creation of an FFR.

a. Leak cause code KZ (Other).

b. Any leak location detail code referring to “other.”

Leak orders cleared with “other” codes shall be reviewed by Field Operations to determine if an FFR is required and/or if the leak order clearance codes need to be changed to more accurately document the clearance of the leak.

4.3 Exceptions and Special Cases

A facility failure report shall not be created, even if the other clearance codes indicate that one should be created, if the cleared by code is 00 (Mistake.)

A facility failure report shall not be created, even if the other clearance codes indicate that one should be created, if the leak cause code is one of the Excavation Damage (C) and Other Outside Force (E) codes, unless the situation involved pipe pulling out of a mechanical fitting. Consult the Gas Standards Engineer or Specialist assigned to your area if you suspect such a situation has occurred.

5. CHANGES TO DPI INFORMATION AFTER THE DPI IS CLEARED

Changes to DPI information for the purpose of records control after the leak is repaired and the DPI is cleared, e.g. DIMP-related adjustments to DPI closure codes or comments, are only required to be made in WMS.

6. REFERRING TO DPI INFORMATION AFTER THE DPI IS CLEARED

WMS shall be used to access DPI information after the leak is repaired and the DPI is cleared. Paper and/or scanned copies may also be used, if necessary, with the understanding that they may not reflect the most current DPI information.

7. RECORDS RETENTION

Destruction of leak orders shall be in accordance with the above and the corporate “Records Management Policy.”

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Instructions for Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair”

Form GS 1708.100-1 “Distribution Plant Inspection and Leakage Repair” (DPI) is used to document the location, classification, and repair disposition of gas leakage. Information related to the numbers and letters on the DPI form shown in the figure below is described in the following section.

1. INSPECTED BY: Signature of person making the inspection in ink.

2. REPORTED TO _______ AT ________ ON _____/____/_____: For Grade 1 and Grade 2+ leaks only: Indicate individual to whom condition was first reported, and time and date. Option for Grades 2 and 3. When time is recorded use the 24-hour clock system. Grade 1 leaks are reported to whomever (Integration Center, crew leader, super visor, etc.). Grade 2+ leaks shall be reported to the appropriate supervisor before the end of the work shift or within 24 hours if the leak is detected after normal working hours.

3. CO*: Note the asterisk. Insert two digit Company code number, which can be found on the back of the DPI form.

4. LOCATION NUMBER: Use appropriate operating location number (4 digit code) where leak area was found.

5. MAP NUMBER: Show map number.

6. SYSTEM NUMBER: Eight character field. Indicate the piping system number (Refer to GS 1660.010 “Piping System Names and Identifiers”) as related to the location of the leak.

7. DATE: Indicate date leak area is found.

8. ORIGINATION CODE*: Note the asterisk. Use code most descriptive of means by which DPI originated. Codes are listed on the back of the DPI form.

9. REFERENCE LEAK ORDER NUMBER: For leak orders originated through a reclassification or positive follow-up inspection the original DPI number shall be recorded.

10. FOOTAGE INSPECTED: Optional. Feet of pipe inspected.

11. LEAK GRADE: Indicated leak grade as follows:

Code	Classification
1	Grade 1
2+	Grade 2+
2	Grade 2
3	Grade 3

12. STREET NAME / RTE ADDRESS LEAK LOCATION: Indicate complete street address, including nearest adjacent house or building number, when available. Examples: 210 Maple St, 511 S Main St

13. MUNICIPALITY: As related to the location of the leak.

14. COUNTY: Do not abbreviate

15. R/R CODE*: No longer completed by the inspector. This is assigned by WMS.

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16. BETWEEN AND: Identify the section of pipe involved by noting the streets intersecting the street identified in Key 12 space. Example: Between 1st St and 2nd St.

17. DETECTOR NUMBER: Record manufacturer's serial number or Company tag number of instrument used to verify leakage. When leak is readily visible, such as a dig-in, record the instrument number used to test for secondary damage. When leakage is verified by a Pressure Drop Test (PDT) or Bubble Leakage Test, enter "PDT" or "soap tested" or equivalent phrase to indicate the test method performed to verify leakage if an instrument was not used.

18. SERVICE OR PLANT ORDER NUMBER: Optional. A leak report originating from a Service type activity, such as a customer call or customer service line survey can be referenced here by recording the service order or other document number.

19. TIME FOUND: Indicate for Grade 1 and Grade 2+ leaks the time at which the leak area was found. Optional for Grade 2 and 3 leaks. "Time Found" is the time that a Company employee arrived at the scene and verified the existence of a leak. When time is recorded use the 24-hour clock system.

20. GPS LONGITUDE (X) COORDINATE: Not required at this time. If used, obtain coordinate from Global Positioning System (GPS) instrument. “X” coordinate will be negative (-) for Company locations. Record instrument reading to six (6) digits to the right of the decimal point for accuracy within one (1) foot.

21. GPS LATITUDE (Y) COORDINATE: Not required at this time. If used, obtain coordinate from Global Positioning System (GPS) instrument. “Y” coordinate will be positive (+) for Company locations. Record instrument reading to six (6) digits to the right of the decimal point for accuracy within one (1) foot.

22. LEAK GRADE CRITERIA: Refer to GS 1714.010 “Leakage Classification and Response,” for lists of classification criteria valid for each leak grade. Refer to Form GS 1708.100-1b “DPI/FFR Field Reference Guide,” for the list of codes to be used to complete this field on the DPI.

23. SKETCH:

    a. Indicate for existing buried facilities in and around the leak area the following, if known or appropriate:
        (1) Company mains – show size, year of installation and approximate location.
        (2) Service – show location of service line(s) and curb box(es.)
        (3) Other facilities – show those facilities which influence leak classification or that should be considered during leak elimination; such as sewers, telephone and electrical conduits, manholes, catch-basins, utility valves and meter boxes. Refer to “Legend” on DPI form.
    b. Show extent of leak area by using shaded area or cloud-like pattern. Refer to “Legend” on the DPI form.
    c. Show prominent structures in or near leak area.
    d. Center leak area and designate center by an “X” on the sketch. Show the distance from the leak area center to a building line, street or alley intersection or other readily-identifiable permanent feature.
    e. Show the highest concentration of gas. Express sustained readings as either “% GAS” or “% LEL.”
    f. Indicate north by circling and marking an “N” near the appropriate arrow or other recognized symbols to indicate north may be used.

24. SURFACE TYPE CODE*: Note the asterisk. Indicate the most descriptive code of the type of surface cover at the suspected leak location, such as asphalt, concrete, gravel, etc. Codes are listed on the back of the DPI form.

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25. TYPE OF AREA: Check appropriate block. When in doubt, check "OUTSIDE BUSINESS DISTRICT (3 YR OR 5 YR SURVEY)." This will ensure that a job order is created if applicable according to the requirements of GS 1714.060 "Leakage Repair Follow-Up Inspections" in the Company's work management system.

26. PROBABLE LEAK SOURCE: Check appropriate block. Check only one block. Note: When the leak source is a critical valve, the valve number must be noted in the remark section.

    The probable leak source is the Company facility where the leak appears to be coming from.

    - Transmission Line: Select this when the probable leak source is on a pipeline that is labeled as "TC" or "Transmission Class" or has the GIS attribute for Pipeline Type indicating "DOT Transmission."
    - Distribution Main: Select this when the probable leak source fits the definition of a "Main" in GS 1012.010 "Definitions."
    - Main Valve: Select this when the probable leak source is a main valve.
    - Service Line: Select this when the probable leak source is on the pipeline from the tapping tee on the main to the inlet of the meter valve. This includes when the probable leak source is a curb valve that is on a service line.
    - Customer Meter Setting: Select this when the probable leak source is on a customer meter setting downstream of the inlet of the meter valve to the outlet of the meter.
    - Station Piping: Select this when the probable leak source is on a pipeline within the site or fenced area of a Point of Delivery (POD) or a district regulator station.

27. JOB ORDER OR ACCOUNT NO.: Use WMS Job Order Number.

28. REMARKS: Use as appropriate to convey any additional information that could assist in the repair or replacement.

29. EXPOSURE DATA: Repair crews shall provide information regarding exposed Main and Service components. Please refer to "LEAK REPAIR CODES - EXPOSURE DATA - MAIN OR SERVICE LINE." Codes are listed on the back of the DPI form. A material code must be provided, except for DPIs "Cleared By" Codes 31, 32, or 33. When using these codes to clear a leak, only "Company Number," "Location Number," and "Cleared By Code," shall be completed along with the "Cleared By" signature and date. An internal corrosion examination shall be performed on any pipe that is cut out (Refer to GS 1440.010 "Internal Corrosion Inspection Requirements.")

    Most of the Exposure Data Codes have meanings that are straightforward. However, for the Soil Type Removed Codes, a few are further explained below:

1	Sand
2	Loam - a mixture between sand, silt, and clay.
3	Clay
4	Rocky
5	Slurry - very wet soil; cannot be stacked.
6	None - use this for no-dig valves, washouts, or exposed facilities.

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30. LEAK CLEARANCE DATA: Repair Crews shall provide data regarding leak clearance as follows. Codes are listed on the back of the DPI form.
    a. Cleared by Code* - Indicate numeric code for method that contributed most to action taken to clear the leakage condition. It is recognized that more than one method may be required to clear a leak area, such as replacing a service line and installing repair devices on the main. In this case, decide which clearance code contributed most to leakage elimination.
    b. Leak Location: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak location. Leak location and detail code combinations that require a Facility Failure Report (FFR) are listed in Exhibit D of this standard.
    c. Leak Cause: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak cause. Leak cause codes that require a Facility Failure Report (FFR) are listed in Exhibit D of this standard.

       If leak cause code KA (Other, Not Exposed) is used to clear a DPI by replacement without excavation to expose the cause of the leak, the leak cause shall be KA, the leak location shall be 51 (Body of Pipe), and the location detail shall match the pipe material shown in company records for the main or service line in question. Use of this code combination shall be monitored by Compliance staff.

    d. Number of Clamps Installed – The value to enter will depend upon the repair method used in the field.

       If repair clamps were installed, enter the number of repair clamps regardless of the size of the clamps used: 1 installed clamp = 1, 2 installed clamps = 2, etc.

       If repair tape in kit form is used, enter the number of kits used in the repair. A partial kit counts as a whole kit.

       If repair tape in bulk form is used, enter the total number of continuous lengths of tape used in the repair, regardless of how much tape is in each length installed. For example, installing a length of tape is 1 repair device. Also installing another length of tape takes the repair device count to 2.

    e. Number Anodes Installed – Indicate the number of anodes installed with the current DPI.
    f. Operating Pressure Code – Indicate type pressure system, codes are shown on the back of the DPI form.
    g. Leak Location Detail: Refer to Form GS 1708.100-1b "DPI/FFR Field Reference Guide," for the list of valid codes for the leak location detail. Leak location and detail code combinations that require a Facility Failure Report (FFR) are listed in Exhibit D of this standard.

31. CLEARED DATE: This is the date that the order was completed and shall agree with the date furnished for the "CLEARED BY" and "DATE" shown in Key 34.

32. REMARKS: Use the "Remarks" space to add any information that would be helpful in the future to anyone searching the records for information on that piece of pipe.

33. REPAIRED BY: Signature of repair crew leader and date when leak order has been cleared either by repair or replacement. When a leak area is cleared by main replacement, it shall not be deemed repaired until the deteriorated section has been physically retired in accordance with procedures.

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34. CLEARED BY: The leak order shall be signed and dated by the person who determines that the area is cleared of leakage, or the order reclassified and a new order written. This may be by a repair crew leader, a leak inspector, a supervisor, or an authorized contractor; however, there shall be an onsite evaluation before the order can be cleared.

35. FOLLOW UP INSPECTION BY: Optional. Defer to Follow Up Inspection Job Order.

36. FOLLOW UP INSPECTION RESULTS: If the inspection is positive, a new DPI shall be written and the new DPI number cross-referenced. See Key 38. The number of the old order shall be recorded in the “Ref. Leak Order No.” block of the new DPI, see Key 9.

37. REINSPECTED BY: Optional. Defer to Reinspect Job Order(s).

38. NEW ORDER NUMBER: Whenever a new DPI is written to replace an existing DPI, due to a reclassification or a positive follow-up inspection result, the new DPI number shall be recorded. See Key 36. The number of the old leak order shall be recorded in the “Ref. Leak Order No.” block of the new DPI, see Key 9.

39. OTHER REFERENCE NUMBER: Related report numbers such as Form GS 1652.010-1 “Facility Failure Report” should be referenced.

40. PIPE TO SOIL POTENTIAL: Pipe to Soil Readings when required on steel pipe will be entered in this block.

41. PROBABLE MAIN KIND: When a DPI is written for a main or a transmission line, enter the type of pipe material (Steel, Plastic, Plastic Insert, Cast Iron, etc.) that is believed to be in the ground based on currently available information.

42. PROBABLE MAIN SIZE: When a DPI is written for a main or a transmission line, enter the type size of pipe that is believed to be in the ground based on currently available information.

43. MADE SAFE INFORMATION: For use in COH and CKY only, when working a grade 1 leak on the segment of a service line located between the property line and the meter.

    a. Person taking action
    b. Made safe time
    c. Made safe date
    d. Made safe action. If a different action is taken than is specified on the form, write the action taken into remarks.

44. PIPE ABOVE GROUND Y/N: Select Y (Yes) if the pipe, as installed, was intended to be above ground. Examples of this situation are: bridge crossings, above-ground header piping or meter set piping. Select N (No) for pipe that was originally buried and was intended to remain buried. Pipe that has been exposed due to erosion, subsidence or other situations where the soil has been removed should still be marked as N (No), because the piping was not supposed to be above ground/exposed. Non-planned exposures shall be reported in accordance with the Operation Center’s local process.

45. LEAK ORDER NUMBER: Also called the DPI number. This identifier is pre-printed onto the form. The current alpha prefix is “D.” All new DPIs must be filled out on forms that carry a “D” alpha prefix.

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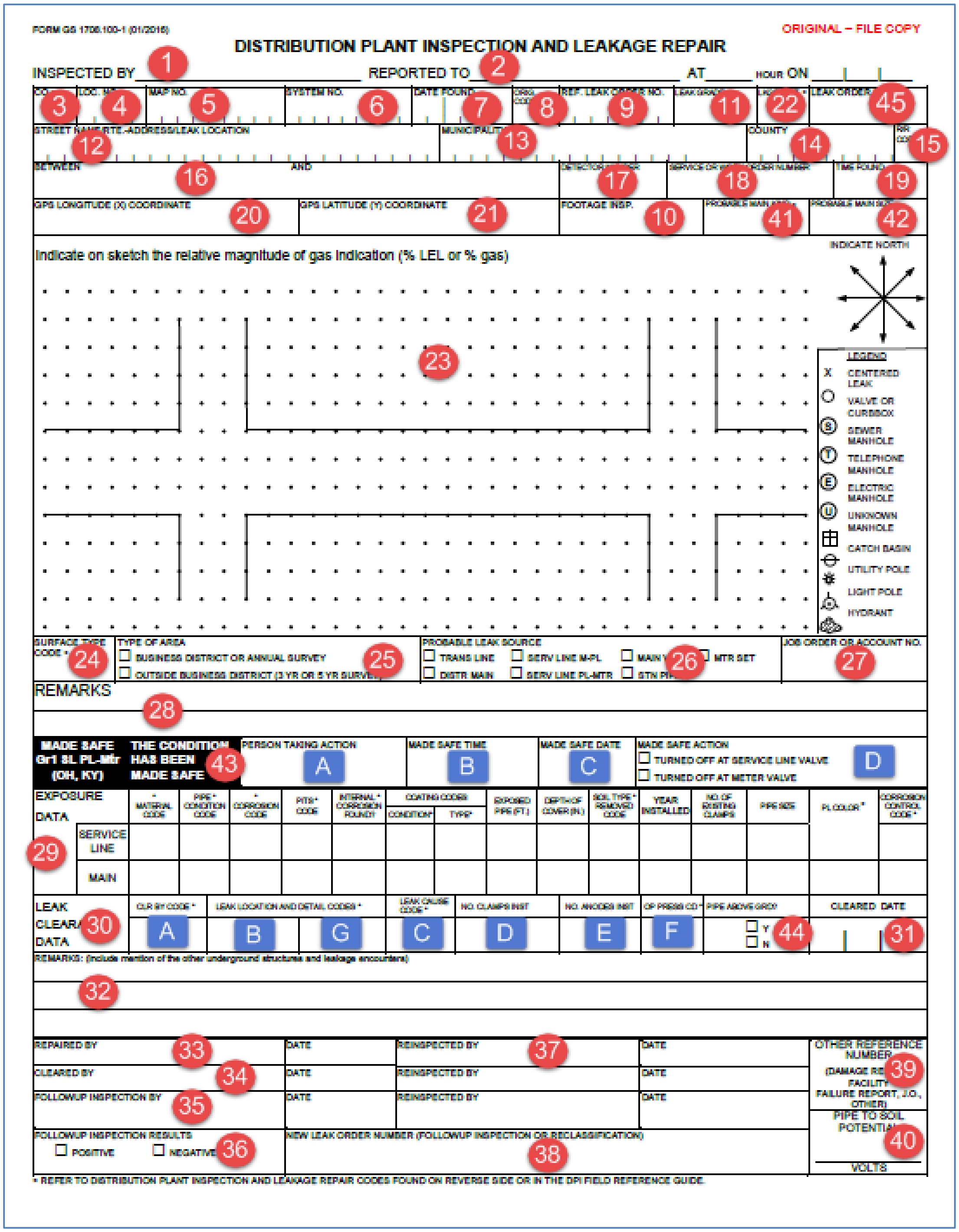

FORM GS 1708.100-1 (01/2016)

ORIGINAL – FILE COPY

DISTRIBUTION PLANT INSPECTION AND LEAKAGE REPAIR

INSPECTED BY 1 REPORTED TO 2 AT HOUR ON

CO. 3 | LOC. NO. 4 | MAP NO. 5 | SYSTEM NO. 6 | DATE FOUND 7 | ORIG. CODE 8 | REF. LEAK ORDER NO. 9 | LEAK GRADE 11 | 22 | LEAK ORDER 45

STREET NAME/RTE.-ADDRESS/LEAK LOCATION 12 | MUNICIPALITY 13 | COUNTY 14 | RR CO. 15

BETWEEN 16 AND | DETECTION INSTR 17 | SERVICE OR WORK ORDER NUMBER 18 | TIME FOUND 19

GPS LONGITUDE (X) COORDINATE 20 | GPS LATITUDE (Y) COORDINATE 21 | FOOTAGE INSP. 10 | PROBABLE MAIN 41 | PROBABLE MAIN SIZE 42

Indicate on sketch the relative magnitude of gas indication (% LEL or % gas) 23

INDICATE NORTH

LEGEND
X CENTERED LEAK
VALVE OR CURBBOX
SEWER MANHOLE
TELEPHONE MANHOLE
ELECTRIC MANHOLE
UNKNOWN MANHOLE
CATCH BASIN
UTILITY POLE
LIGHT POLE
HYDRANT

SURFACE TYPE CODE * 24 | TYPE OF AREA ☐ BUSINESS DISTRICT OR ANNUAL SURVEY ☐ OUTSIDE BUSINESS DISTRICT (3 YR OR 5 YR SURVEY) 25 | PROBABLE LEAK SOURCE ☐ TRANS LINE ☐ SERV LINE M-PL ☐ MAIN 26 ☐ MTR SET ☐ DISTR MAIN ☐ SERV LINE PL-MTR ☐ STN PIPE | JOB ORDER OR ACCOUNT NO. 27

REMARKS 28

MADE SAFE Gr1 SL PL-Mtr (OH, KY) | THE CONDITION HAS BEEN MADE SAFE 43 | PERSON TAKING ACTION A | MADE SAFE TIME B | MADE SAFE DATE C | MADE SAFE ACTION ☐ TURNED OFF AT SERVICE LINE VALVE ☐ TURNED OFF AT METER VALVE D

EXPOSURE DATA 29 | MATERIAL CODE | PIPE CONDITION CODE | CORROSION CODE | PITS CODE | INTERNAL CORROSION FOUND? | COATING CODES CONDITION TYPE | EXPOSED PIPE (FT.) | DEPTH OF COVER (IN.) | SOIL TYPE REMOVED CODE | YEAR INSTALLED | NO. OF EXISTING CLAMPS | PIPE SIZE | PL COLOR | CORROSION CONTROL CODE
SERVICE LINE
MAIN

LEAK CLEARANCE DATA 30 | CLR BY CODE * A | LEAK LOCATION AND DETAIL CODES * B G | LEAK CAUSE CODE * C | NO. CLAMPS INST D | NO. ANODES INST E | OP PRESS CD F | PIPE ABOVE GRD? ☐ Y ☐ N 44 | CLEARED DATE 31

REMARKS: (Include mention of the other underground structures and leakage encountered) 32

REPAIRED BY 33 | DATE | REINSPECTED BY 37 | DATE | OTHER REFERENCE NUMBER (DAMAGE REPORT, FACILITY FAILURE REPORT, J.O., OTHER) 39
CLEARED BY 34 | DATE | REINSPECTED BY | DATE
FOLLOWUP INSPECTION BY 35 | DATE | REINSPECTED BY | DATE | PIPE TO SOIL POTENTIAL 40
FOLLOWUP INSPECTION RESULTS ☐ POSITIVE ☐ NEGATIVE 36 | NEW LEAK ORDER NUMBER (FOLLOWUP INSPECTION OR RECLASSIFICATION) 38 | VOLTS

* REFER TO DISTRIBUTION PLANT INSPECTION AND LEAKAGE REPAIR CODES FOUND ON REVERSE SIDE OR IN THE DPI FIELD REFERENCE GUIDE.

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LEAK REPAIR CODES - EXPOSURE DATA - MAIN OR SERVICE LINE

CODE	MATERIAL
S	STEEL
P	PLASTIC
CI	CAST IRON
WI	WROUGHT IRON
OT	OTHER
CU	COPPER
PI	PLASTIC INSERT
ST	STEEL TREATED

CODE	PIPE CONDITION
G	GOOD
F	FAIR
P	POOR

CODE	CORROSION
N	NONE
G	GENERALIZED
P	LOCALIZED PITTING
C	CAST IRON GRAPHITIZATION

CODE	PROBABLE MAIN KIND
CI	CAST IRON
CU	COPPER
OT	OTHER
P	PLASTIC
PI	PLASTIC INSERT
S	STEEL
ST	STEEL, TREATED
WI	WROUGHT IRON
UN	UNKNOWN

CODE	PITS
N	NONE
S	SHALLOW
D	DEEP

CODE	INTERNAL CORROSION FOUND?
Y	YES
N	NO
X	INTERIOR NOT EXAMINED

CODE	COATING CONDITION
N	NONE
G	GOOD
P	POOR

CODE	COATING TYPE
CT	COAL TAR- BLACK
EX	EXTRUDED-YELLOW OR BLACK
WA	WAX-BLACK OR BROWN
EP	EPOXY-WHITE, GREEN OR BROWN
CJ	COATED JOINT OR FITTING
OT	OTHER
NO	NONE
TP	TAPE

CODE	SOIL TYPE REMOVED
1	SAND
2	LOAM
3	CLAY
4	ROCKY
5	SLURRY
6	NONE

CODE	CORROSION CONTROL TYPE
C	CATHODICALLY PROTECTED
M	MITIGATED
N	NO. C.P./MITIGATION
U	UNKNOWN

LEAK REPAIR CODES - LEAK CLEARANCE DATA

CLEARED BY CODE

00 - MISTAKE (COMMENTS REQUIRED)
21 - MAIN REPAIR-COMPANY
22 - MAIN REPAIR-CONTRACTOR
23 - MAIN REPLACEMENT OR ABANDONMENT-COMPANY
24 - MAIN REPLACEMENT OR ABANDONMENT-CONTRACTOR
25 - COMPANY SERVICE LINE REPAIR-COMPANY
26 - COMPANY SERVICE LINE REPAIR-CONTRACTOR
27 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT-COMPANY
28 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT-CONTRACTOR
31 - LEAKAGE IS ON CUSTOMER OWNED FACILITY
32 - LEAKAGE IS ON FOREIGN COMPANY'S FACILITY OR DET. TO BE STRAY GAS
33 - NEGATIVE READINGS
34 - RECLASSIFIED
35 - PLANT REGULATOR/STATION PIPING/AUXILIARY EQUIPMENT REPAIRED
36 - SERVICE METER/REGULATOR/SETTING REPAIRED
37 - CUSTOMER SERVICE LINE REPAIR-COMPANY
38 - CUSTOMER SERVICE LINE REPAIR-CONTRACTOR
39 - CUSTOMER SERVICE LINE REPLACEMENT OR ABANDONMENT-COMPANY
40 - CUST. SERVICE LINE REPLACEMENT OR ABANDONMENT-CONTRACTOR
41 - VALVE REPAIR - DIG
42 - VALVE REPAIR – NON-DIG
43 - VALVE REPAIR – POT HOLE
44 - PLANT REGULATOR/STATION PIPING/AUXILIARY EQUIPMENT REPLACED
45 - SERVICE METER/REGULATOR/SETTING REPLACED

LEAK GRADE CRITERIA

REFER TO THE DPI FIELD REFERENCE GUIDE

LEAK CAUSE CODES, LEAK LOCATION AND DETAIL CODES

REFER TO THE DPI FIELD REFERENCE GUIDE

OPERATING PRESSURE CODE

LP - LOW PRESSURE (UNDER 1 PSIG)
IP - INTERMEDIATE PRESSURE (1 TO 10 PSIG)
MP - MEDIUM PRESSURE (OVER 10 TO 60 PSIG)
HP - HIGH PRESSURE (OVER 60 PSIG)

PLASTIC COLOR

01 BLACK
02 BLACK WITH YELLOW STRIPES
03 GRAY
04 ORANGE
05 PINK
06 RED
07 TAN
08 WHITE
09 YELLOW
10 OTHER (PROVIDE COMMENTS)

LEAK INSPECTION CODES

CO. (COMPANY) CODES

32 - COLUMBIA GAS OF KENTUCKY, INC.
34 - COLUMBIA GAS OF OHIO, INC.
35 - COLUMBIA GAS OF MARYLAND, INC.
37 - COLUMBIA GAS OF PENNSYLVANIA, INC.
38 - COLUMBIA GAS OF VIRGINIA, INC.
80 - COLUMBIA GAS OF MASSACHUSETTS

LEAK GRADE CODE

1 - GRADE 1 LEAK
2+ - GRADE 2 PRIORITY LEAK
2 - GRADE 2 LEAK
3 - GRADE 3 LEAK

R/R (REPLACE OR REPAIR) CODE

00 - REINSPECT GRADE 3 ONLY
01 - REPAIR MAIN OR COMPANY SERVICE LINE
02 - COMPANY SERVICE LINE REPLACEMENT OR ABANDONMENT
03 - MAIN REPLACEMENT OR ABANDONMENT, OR SERVICE LINE REPLACEMENT ASSOCIATED WITH MAIN REPLACEMENT
04 - CUSTOMER SERVICE LINE REPAIR, REPLACEMENT OR ABANDONMENT
05 - MAIN RETIRE / ABANDONMENT
07 - MITIGATION INSTALLATION

ORIG (ORIGINATION) CODE

00 - MISTAKE DPI #
01 - PROGRAMMED PLANT SURVEY
02 - SUPPLEMENTAL SURVEY
03 - PATROL
04 - CUST. SERV. LINE INSPECTION, INCL. BLDG. INSP.
05 - DIG-IN CALL
06 - POLICE OR FIRE
07 - SERVICE DEPARTMENT
08 - CUSTOMER/PUBLIC CALL
09 - RECLASSIFICATION
10 - FOLLOW-UP INSPECTION
11 - OTHER COMPANY OR CONTRACTOR ACTIVITY
12 - MITIGATION SURVEY
13 - MITIGATION INSTALLATION
14 - PROPANE SYSTEM

\# WORK MANAGEMENT ONLY

SURFACE TYPE CODE

CODE	DESCRIPTION	CODE	DESCRIPTION
ASPHALT	ASPHALT	WATER	SUBMERGED
BRICK	BRICK	EXPOSED	EXPOSED DUE TO EROSION
CONCRETE	CONCRETE	ABOVEGRD	DESIGNED ABOVE GROUND
GRAVEL	GRAVEL	OTHER	OTHER (COMMENTS REQD)
SOIL	SOIL		

Distribution Operations

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EXHIBIT B
(1 of 1)

PROCESS DATE 10-11-89
REPORT DATE 10-19-89

COLUMBIA GAS DISTRIBUTION COMPANY
LEAKAGE INSPECTION SCHEDULE
LOCATION 1326

DP2740-01
PAGE 7

INSPECTION SCHED 5

REQUEST	UNIT	BOOK	INSPECT YEAR	NUMBER OF CUSTOMERS
	18	07	1985	204
			1986	2
			1987	2
			1988	2
			1989	2
	19	07	1985	289
			1986	3
			1987	3
			1988	4
	19	20	1989	285
	20	05	0000	1
			1987	264
			1988	7
			1989	7
	20	20	1989	139
	21	02	1900	2
			1980	1
			1984	11
			1986	1
			1989	108
	21	05	1989	178
	TOTALS		0000	7
			1900	4
			1980	1
			1984	22
			1985	697
			1986	1941
			1987	2163
			1988	1894
			1989	2021

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Distribution Operations

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EXHIBIT C
(1 of 1)

PROCESS DATE 10-19-89
REPORT DATE 10-31-89
INSPECTION CODE 5 UNIT/BOOK 19 91

COLUMBIA GAS DISTRIBUTION COMPANY
LEAKAGE SURVEY RECORDS
LOCATION 2225 REPORT NUMBER 020487

DP2790-01
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MTR LOC / KS	MTR NBR / MTR INST / LAST INSP	DATE OF INSP	METHD OF INSP	CUSTOMER NAME / SERVICE ADDRESS / SERVICE CITY, STATE	CUST PHONE	MASTER TAP LOC / CURB BOX LOC / CUST VALVE LOC	MT SERV / SPEC LGTH / PSID NBR	OUT-SIDE RSLT	IN-SIDE RSLT	ORDER NUMBER	CGI CARD LEFT
602 94	8651709 000000 00-1998			SAMMY ANGOTT 120 HELEN ST WASHINGTON PA	000-000-0000	METER VALVE	400249800				
818 88	D412550 000000 00-1998			L TIANO JR 132 HELEN ST WASHINGTON PA	000-000-0000	METER VALVE	400249801				
818 88	2233114 000049 90-1998			GEORGE D LEHEW 210 HELEN ST WASHINGTON PA	000-225-9694	48FFB 27LRB METER VALVE	400249802				
608 88	7964159 000000 00-1998			SUSAN C BURCHETT 149 HELEN ST WASHINGTON PA	000-222-7238	METER VALVE	400249803				
755 88	3662383 000000 00-1998			CARL DAVIDSON 119 HELEN ST WASHINGTON PA	000-000-0000	3FFM METER VALVE	400249804				
755 88	3662563 000000 00-1998			FRANK F JUNKO JR 109 HELEN ST WASHINGTON PA	000-000-0000	METER VALVE	400249805				
818 88	2089233 000000 00-1998			TONY ANGOTT 104 KIMBERLY DR WASHINGTON PA	000-000-0000	METER VALVE	400249810				
630 88	4613948 000000 00-1998			JOHN BECK 153 KIMBERLY DR WASHINGTON PA	000-000-0000	63FFB 2RLB METER VALVE	400249806				
818 88	681086 000049 90-1998			CHARLES SARNICKE 143 KIMBERLY DR WASHINGTON PA	000-000-0000	1FM METER VALVE	400249807				
818 92	1081362 000000 00-1998			SAMUEL J INSANA JR 133 KIMBERLY DR WASHINGTON PA	000-225-6905	58FFB 2RRB METER VALVE	400249808				
630 88	2757369 000000 00-1998			MARK A CONNOLLY 123 KIMBERLY DR WASHINGTON PA	000-111-1111	METER VALVE	400249809				
608 88	7434165 000000 00-1998			NORMAN G HORNER 32 KIMBERLY DR WASHINGTON PA	000-000-0000	6FM METER VALVE	400249811				
814 88	5919371 000000 00-1998			GEORGE MCCONNELL 1114 W WYLIE AV WASHINGTON PA	0[illegible] 000-0000	SEE SKETCH METER VALVE	400249812				

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EXHIBIT D (1 of 3)

DPI CLEARANCE CODES REQUIRING A FFR

Leak Location Code		Leak Location Detail Code		Company
56	BELL & SPIGOT JOINT	01	EXISTING REPAIR CLAMP	All
65	REPAIR DEVICE	01	CLAMP	All
66	FITTINGS - STEEL	02	COUPLING - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	03	COUPLING - THREADED	CGV
66	FITTINGS - STEEL	05	INLINE TEE - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	06	INLINE TEE - THREADED	CGV
66	FITTINGS - STEEL	08	SERVICE SADDLE - MECHANICAL	All
66	FITTINGS - STEEL	10	SERVICE SADDLE TEE - MECHANICAL	All
66	FITTINGS - STEEL	12	SERVICE TEE - THREADED	CGV
66	FITTINGS - STEEL	17	ELL - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	18	ELL - THREADED	CGV
66	FITTINGS - STEEL	20	END CAP - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	22	OTHER - MECHANICAL COMPRESSION	All
66	FITTINGS - STEEL	23	OTHER - THREADED	CGV
67	FITTINGS - PLASTIC	01	COUPLING - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	05	COUPLING - STAB	All
67	FITTINGS - PLASTIC	06	COUPLING - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	07	INLINE TEE - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	11	INLINE TEE - STAB	All
67	FITTINGS - PLASTIC	12	INLINE TEE - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	13	SERVICE SADDLE TEE - MECHANICAL	All
67	FITTINGS - PLASTIC	17	SERVICE TEE CAP - THREADED	All
67	FITTINGS - PLASTIC	18	ELL - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	22	ELL - STAB	All
67	FITTINGS - PLASTIC	23	ELL - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	24	END CAP - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	28	END CAP - STAB	All
67	FITTINGS - PLASTIC	29	END CAP - LYCOFIT/METFIT	All
67	FITTINGS - PLASTIC	30	OTHER - MECHANICAL COMPRESSION	All
67	FITTINGS - PLASTIC	35	OTHER - STAB	All
67	FITTINGS - PLASTIC	36	OTHER - LYCOFIT/METFIT	All

EXHIBIT D
(2 of 3)

DPI CLEARANCE CODES REQUIRING A FFR

Leak Location Code		Leak Location Detail Code		Company
68	SERVICE RISER - PLASTIC	01	FIELD ASSEMBLED	All
68	SERVICE RISER - PLASTIC	02	FACTORY ASSEMBLED	All
69	SERVICE RISER - STEEL	01	FIELD ASSEMBLED	All
69	SERVICE RISER - STEEL	02	FACTORY ASSEMBLED	All
69	SERVICE RISER - STEEL	03	METALLIC FITTING ASSEMBLED	All
71	VALVE - PLASTIC	04	SERVICE LINE VALVE - BALL - MECHANICAL	All
71	VALVE - PLASTIC	05	SERVICE LINE VALVE - BALL - STAB	All
71	VALVE - PLASTIC	09	SERVICE LINE VALVE - PLUG - MECHANICAL	All
71	VALVE - PLASTIC	10	SERVICE LINE VALVE - PLUG - STAB	All
71	VALVE - PLASTIC	14	MAIN LINE VALVE - BALL - MECHANICAL	All
71	VALVE - PLASTIC	18	MAIN LINE VALVE - PLUG - MECHANICAL	All
72	VALVE - STEEL	07	SERVICE LINE VALVE - BALL - MECHANICAL	All
72	VALVE - STEEL	11	SERVICE LINE VALVE - PLUG - MECHANICAL	All

EXHIBIT D
(3 of 3)

DPI CLEARANCE CODES REQUIRING A FFR

Leak Cause Code		Company
FA	ABOVE GROUND THREADED CONNECTION	CGV
FB	BELOWGRADE THREADED CONNECTION	CGV
FD	DEFECTIVE BODY OF PIPE	All
FE	DEFECTIVE COMPONENT BODY	All
FF	DEFECTIVE FUSION JOINT	All
FG	DEFECTIVE PIPE SEAM	All
FH	DEFECTIVE WELD	All
FJ	MECHANICAL FITTING	All
FK	REPAIR DEVICE FAILURE	All
FZ	OTHER MATERIAL FAILURE	All
GA	DOPING/CAULKING/O-RING	CGV
GB	MALFUNCTION OF CONTROL/RELIEF EQUIPMENT - DEBRIS ON SEAT	All
GC	MALFUNCTION OF CONTROL/RELIEF EQUIPMENT - OTHER	All
GD	VALVE FAILURE/PACKING	All
GZ	OTHER EQUIPMENT FAILURE	All
HA	INADEQUATE/NOT FOLLOWED PROCEDURE	All
HB	LOOSE CONNECTION	All
HC	STRIPPED THREADS	All
HZ	OTHER OPERATOR ERROR	All

Effective Date: 01/01/2014	**Leakage Classification and Response**	Standard Number: **GS 1714.010(KY)**
Supersedes: 07/01/2011		Page 1 of 8

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE 49 CFR Part 192.706, 192.709, 192.723

1. LEAKAGE CLASSIFICATION AND RESPONSE

All leaks shall be classified as either a Grade 1, 2 (i.e., 2 or 2+), or 3 according to the criteria in Tables 1, 2, and 3. "All leaks" means leaks found on jurisdictional facilities, including mains, company service lines, customer service lines, customer meter settings, etc.

Evaluating leaks and determining the leak grade may require equipment capable of indicating the concentration of gas. The lower explosive limit of gas is a concentration of 5% gas in air. When evaluating any gas leak indication, the initial step is to determine the perimeter of the leak area. When this perimeter extends to a building wall, the investigation should continue into the building. Classification of the leak takes into account both the concentration of gas and the perimeter of the leak area.

Responding employees shall take all necessary actions directed toward protecting people first and then property.

"Cleared" as used in this procedure means the source of the leak has been eliminated by repairing, replacing, or retiring the facility.

The "leakage area" concept, as used in this procedure, is the basis for describing the extent of the leakage reported for a particular leak record. A leakage area is an area of positive combustible gas indicator (CGI) tests surrounded by an area of negative CGI tests. A separate leak record shall be made for each "leakage area." It may include mains and service lines, a single main, several mains and/or a single or several service lines. The only exceptions are:

a. Continuous leakage in a platted (i.e., urban, suburban, business) area exceeding one block in length. A separate leak record shall be prepared for each full block or part of a block. When a leakage area extends into two or more blocks, two or more leak records are required. They shall be cross-referenced to each other to indicate that each is a continuation of the same leakage area and a common intersection should be shown on each leak record.

b. Continuous leakage in an un-platted (i.e., cross country, rural) area exceeding 500 feet in length. A separate leak record shall be prepared for each 500 feet or part of 500 feet. When a leakage area extends beyond a 500 foot area, two or more leak records are required. They shall be cross-referenced to each other to indicate that each is a continuation of the same leakage area.

c. Cast-iron or mechanically coupled lines indicating consecutive joint leakage shall be reported on one leak record even though the leakage areas do not run together. If, after a thorough investigation, the leakage inspector cannot determine that the leakage is entirely joint leakage, a separate leak record shall be written for each leakage area. A separate leak record shall also be prepared for isolated joint leakage.

d. Not more than one leak record is to be made for a service line, regardless of the number of leakage areas found on the service line.

The following tables provide the definition of each leak classification, response criteria, and examples of conditions for each classification. When a leak is reevaluated, a qualified person shall classify the leak being reevaluated using the classification criteria listed in the tables below. Examples of conditions listed for each classification in the tables below are not all inclusive. For the purposes of the tables below, “building” is defined as a structure which is occupied or likely to be occupied or has a potential source of ignition.

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Effective Date: 01/01/2014	Leakage Classification and Response	Standard Number: GS 1714.010(KY)
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Table 1

Grade 1 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**
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.	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 Company's emergency plan. 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. *Follow-up inspection:* Where there is residual gas (residual gas is defined as gas remaining in the soil after the leak is cleared and is expected to dissipate through normal means) in the ground after the repair of a Grade 1 classified leak, a follow-up inspection shall be conducted as soon as practical after allowing the soil atmosphere to vent and stabilize, but in no case later than the last day of the next calendar month following the repair date. See GS 1714.060 "Leakage Repair Follow-Up Inspections" for additional requirements.	**Examples of classification criteria that indicate a Grade 1 classified leak include the following.** a. Any leak which, in the judgment of the person performing the inspection, is regarded as an immediate hazard. b. Blowing gas that (1) creates a serious operating problem or hazard, such as the possibility of ignition, or (2) has ignited. c. Any indication of gas which has migrated into or under a building. d. Any indication of underground migration to an outside wall of a building, or where gas would likely migrate to an outside wall of a building. e. Any sustained reading of 4% gas, or greater, in any subsurface structure (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person, and in which gas could accumulate. f. Any sustained reading of 4% gas, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building or to a source of ignition. g. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property. h. Sustained readings in consecutive manholes, catch basins or substructures. i. An above ground leak confirmed by an approved instrument or bubble leak test, with blowing/hissing sound, within close proximity to a building, that in the judgment of the person performing the inspection is an immediate hazard.

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Table 2

Grade 2 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**[1]
A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	**<u>Grade 2 Classified Leaks - Normal Schedule Repair</u>** Many Grade 2 classified leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic re-evaluation. Grade 2 classified leaks not cleared shall be reevaluated* not later than the last day of the sixth (6th) month following the date the leak is discovered or last reevaluated until cleared; and either: a. repaired not later than the last day of the fifteenth (15th) month from the date the leak is discovered; or b. eliminated by replacing or retiring the pipeline containing the leak by the last day of the twenty-fourth (24th) month from the date the leak is discovered. NOTE: If a capital replacement project that will clear a Grade 2 classified leak is cancelled after fifteen (15) months from the date the leak was discovered, the leak must be cleared by the commit date of the capital work order. *When a leak is to be reevaluated, it shall be classified in accordance with the criteria listed in this procedure.	**Examples of classification criteria that indicate a normal schedule repair Grade 2 classified leak include the following.** a. Any sustained reading of 2% gas, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 classified leak. b. Any sustained reading of 5% gas, or greater, under a street in a wall-to-wall paved area that does not qualify as a Grade 1 classified leak. c. Leakage that has spread to both sides of a paved driveway and/or shows indications of migrating along the driveway toward a building. d. Sustained readings on both sides of a street or corners of an intersection. e. Any sustained reading less than 4% gas in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. f. Any sustained reading of less than 4% gas in any subsurface structure (such as vaults, tunnels, catch basins, or manholes) of sufficient size to accommodate a person, and in which gas could accumulate. g. Any sustained reading of 4% gas, or greater, in small gas associated substructures (e.g., curb box, valve box). h. Any leak which, in the judgment of the person performing the inspection, is of sufficient magnitude to justify scheduled repair. i. An above ground leak confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection is of sufficient magnitude to justify scheduled repair. j. Any corrosion leak on an exposed facility within 100 feet of a building. k. A leak that hisses or blows slightly in an un-platted (i.e., cross country, rural) area, and is in a location where accidental ignition is not likely to occur.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

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Table 2 (Continued)

Grade 2 Classification and Response		
	Response Criteria	**Examples of Classification Criteria[1]**
	<u>Grade 2 Classified Leaks Requiring Accelerated Schedule Repair (i.e., 2+)</u> Grade 2 classified leaks may vary greatly in degree of potential hazard. Some Grade 2 classified leaks, when evaluated by the classification criteria, may justify an accelerated scheduled repair. These situations should be reported to the appropriate supervisor before the end of the work shift or within 24 hours if the leak is detected after normal working hours. These Grade 2 classified leaks requiring accelerated schedule repair shall be reduced to non-hazardous classification, cleared, or, if not company facilities, turned over to the responsible outside party not later than twenty-one (21) calendar days from the date found. *Follow-up inspection*: See GS 1714.060 "Leakage Repair Follow-Up Inspections" for additional requirements.	**Examples of classification criteria that indicate the need for an accelerated schedule (priority) repair Grade 2 classified leak include the following.** a. Any leakage condition which, in the judgment of the person performing the inspection, is serious enough to warrant action in a few days. b. A leakage area close to but not against a foundation or building wall. c. Leakage on a service line under continuous paving from leak area to building wall. d. Leakage detected which would likely migrate to the outside wall of a building under existing or imminent frost conditions. e. Sustained CGI (hot wire) reading of less than 4% gas in a manhole, conduit, catch basin or tunnel (other than a gas associated substructure) in an area with wall to wall pavement. f. An above ground leak confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection is of sufficient magnitude to require an accelerated repair schedule.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

Table 3

Grade 3 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**[1]
A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	Except as noted below, Grade 3 classified leaks not cleared shall be reevaluated* a. during the next scheduled leakage survey, or b. not later than the last day of the fifteenth (15 th) month following the date the leak is discovered or last reevaluated, (whichever is sooner), and continue to be reevaluated on that same frequency until the leak is cleared or reclassified. Exception: Open Grade 3 classified leaks that do not produce a detectable reading during the scheduled leakage survey are not required to be reevaluated but shall remain open until cleared. Any leak detected during the scheduled leakage survey shall be reevaluated.* *Reevaluated means classifying the leak in accordance with this procedure.	**Examples of classification criteria that indicate a Grade 3 classified leak include the following.** a. Any sustained reading of less than 4% gas in small gas associated substructures. b. Any sustained 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. c. An above ground leak that is not caused by corrosion, confirmed by an approved instrument or bubble leak test, that in the judgment of the person performing the inspection can be reasonably expected to remain non-hazardous.

[1] These are examples of minimum classifications; if there is any doubt when classifying a leak, a higher classification should be used.

2. RECLASSIFICATION AND CLEARANCE OF LEAKS

A classified leak shall be cleared only after an on-site evaluation by a person qualified in leak classification. Normally, the indication of gas within a leakage area should be eliminated before the classified leak is cleared.

After initial classification, a Grade 2 or Grade 3 classified leak may be reclassified based on a thorough on-site investigation by a person qualified in leak classification. However, a reclassification of a Grade 1 classified leak can only be accomplished by performing a physical action on the facility, such as repair, replacement, or retirement.

For a Grade 1 classified leak, if a physical action has been taken on the facility to reduce the leakage to a non-hazardous condition, the leak may be reclassified. Although venting and purging may temporarily remove the hazardous condition, these actions are not justification to reclassify a Grade 1 or a Grade 2 leak.

2.1 Temporary Repairs

If a temporary repair has been made to reduce or eliminate the leakage, the leak shall be reclassified to a Grade 2, which can only be cleared by performing an approved permanent repair technique or by replacement.

For Grade 1 leakage conditions found on a customer service line, the curb stop (valve) may be turned off and the repair scheduled if the gas readings dissipate and the leakage area is made safe. Venting and purging may be required to assist in dissipating the gas. The temporary action taken to eliminate the hazardous condition must be documented on the leak order or work management system. The documentation should include the following:

a. date and time,

b. person verifying the made safe condition, and

c. the statement, “The condition has been made safe.”

2.2 Negative Indications

When an authorized company or contractor representative is dispatched to clear or reevaluate a leak and is unable to detect any indication of gas after a thorough investigation by a person qualified in leak classification, the leak record may be cleared.

A “thorough investigation” includes inspecting the entire area surrounding the previously determined leakage area using an approved leakage survey method, checking all facilities, foundation walls, available openings, and other areas where gas could escape to the atmosphere, and verifying the leakage area no longer exists. Refer to GS 1708.070 “Outside Leak Investigation” and/or GS 1714.030 “Leakage

Pinpointing" for additional guidance.

2.3 Leakage on Other Operators' Facilities

A leak subsequently discovered to be on another company's facilities is cleared by notifying the other company. After the leakage is reported to the outside company, operator, or owner, a notation of the method of notification, the name of the person notified, and the time and date of notification shall be documented on the leak record.

Hazardous (or Grade 1 classified) leaks require immediate notification to the operator and/or a public safety official. Company personnel shall take appropriate actions until the hazard to life and property has been eliminated or reduced to a safe level, or the responsible outside party has taken over efforts in the field. "Appropriate actions" in this case includes establishing a perimeter, evacuating as needed, and monitoring the hazardous condition.

NOTE: It is important to properly document all contacts and correspondence with public safety officials and other operators. Regardless of the method of initial notification, written notification shall follow-up other forms of notice and should include a copy of the leak record written by the Company.

3. RESPONSES INVOLVING REPAIRS, REPLACEMENT OR ABANDONMENT

Leaks that are eliminated by repair, replacement, or abandonment shall be done in accordance with the Company's gas standards for repair, replacement, or abandonment.

For repair guidance see GS 1714.020 "Leakage: Distribution Pipe Repair" and GS 1730.010 "Transmission Line Field Repair."

The Company's construction gas standards address replacement and abandonment requirements.

4. RECORDS

Leakage information is to be documented on the applicable Company forms (i.e., Form GS 1708.100-1 "Distribution Plant Inspection and Leakage Repair" (DPI)) and/or in the work management system. Refer to GS 1708.100 "Leakage Control Records" for more information.

The Company shall retain leakage records for at least the life of the pipeline, but not less than 10 years from the cleared date. Exceptions include records of leaks with negative indications after a reevaluation (see Section 2.2 above), which may be discarded after 10 years from the cleared date.

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Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Leakage: Distribution Pipe Repair**	Standard Number: **GS 1714.020**
Supersedes: 07/01/2014		Page 1 of 11

Companies Affected:

☑ NIPSCO	☐ CGV	☑ CMD
	☑ CKY	☑ COH
	☐ CMA	☑ CPA

REFERENCE 49 CFR Part 192.703

1. GENERAL

When repairing gas pipelines, all applicable Company safety procedures shall be followed to protect personnel and the public from hazards. Only those directly involved with the repair work should be in the work area. Care shall be taken when excavating around the pipeline and pipe exposure should be limited so that additional damage does not occur. The pipe on both sides of the known defect shall be assessed to determine if additional defects are present.

Each segment of pipeline that becomes unsafe, i.e., it has been found to be damaged or deteriorated to the extent that its serviceability is impaired (see guidance in sections below) or it has developed leakage classified as Grade 1, must be replaced, repaired, or removed from service. Refer to the applicable GS 1714.010 "Leakage Classification and Response" for leakage response requirements for all leak classifications.

Defect as used in this gas standard includes leaks, dents, gouges, and defective welds.

If temporary measures or repairs were made, as soon as practical, the pipe shall be repaired using a permanent method.

Consider taking the pipeline out of service or reducing the operating pressure as low as practical/feasible before attempting to uncover the pipeline. Whenever the repair requires interrupting the pressure in the line, gauges shall be installed and monitored to ensure that adequate pressure is maintained.

The pressure rating of a permanent repair device shall meet or exceed the Maximum Allowable Operating Pressure (MAOP) of the pipeline. The pressure rating of a temporary repair device shall meet or exceed the operating pressure of the pipeline during the period of time that the repair device is in-service. A temporary repair device that does not meet or exceed the MAOP of the pipeline may remain, only if it is encapsulated with a repair device that meets or exceeds the MAOP of the pipeline.

See GS 1730.010 “Transmission Line Field Repair” and GS 1714.030 “Pinpointing” for additional guidance.

2. REPAIRS ON METALLIC PIPES

Generally repairs on a metallic system are performed by the use of an external repair clamp. Common types of leaks can be repaired with band and saddle clamps, collar clamps, split repair clamps (mechanical or weld), bell joint clamps, and screw fitting clamps. Other approved repair methods, such as anaerobic injection (e.g., Permabond gaseal) and encapsulation, can also be used.

Refer to manufacturer's instructions for the pressure ratings and limitations for the selected repair method.

2.1 Preliminary Assessment

When exposing pipe where restraint style couplings can't be verified or the method of joining is unknown, only one joint of pipe should be exposed at a time. This joint should be treated and backfilled prior to exposing additional pipe. The intent is to limit the number of couplings exposed at any one time.

2.1.1 Mechanical Couplings

The following additional precautions are recommended to help prevent coupling pullout when repairing elevated pressure or large diameter pipelines joined by mechanical couplings.

When repairing existing pipelines, consider the possibility that couplings could exist in the pipeline and could potentially separate when soil, that provides passive restraint, is removed. Maps and records may identify the presence of couplings as well as the lengths of pipe joints used.

To reduce the possibility of coupling pull-out, consider blocking offset fittings which were not strapped or blocked, with concrete by encasing the pipeline. Contact Engineering for recommended blocking sizing. Also, plan for protection of the pipeline from damage due to the concrete, e.g., installation of coating and tape wrap, installation of rock shield, etc. Contact the Corrosion department prior to encasing the pipe for corrosion recommendations.

Refer to GS 1320.010 "Mechanical Coupling Connections" for additional guidelines.

When tying-in while making repairs, refer to GS 1680.010 "Tie-ins and Tapping Pressurized Pipelines."

2.1.2 Evaluate the Defect

Consider the age of the pipeline and type of the defect. Take caution when evaluating defects on higher pressure pipelines such as sharp mechanical damage, dents, old defects, and/or defects that have been in service for an unknown length of time. Defects such as sharp or deep gouges and dents may have cracked during service and need to be handled with caution.

2.2 Defects Involving Corrosion

2.2.1 Localized Corrosion

Localized corrosion pitting is an area on the pipe surface that contains corrosion pits over a non-contiguous area. Localized corrosion does not always affect a pipe's serviceability.

Defects involving leaks in areas of localized corrosion can generally be repaired using an appropriate leak clamp.

2.2.2 General Corrosion

General corrosion is considered corrosion pitting so closely grouped as to affect the overall strength of the pipe and should be considered as affecting the pipeline's serviceability.

Defects involving leaks in areas of general corrosion can be temporarily repaired using an appropriate leak clamp. Supervision should be notified to arrange for permanent repair.

NOTE: Supervision should be notified of defects involving general corrosion prior to backfilling.

2.3 Cast Iron and Ductile Iron Considerations

2.3.1 Graphitization

Graphitization is the process where the ferrous (iron) portion of the cast-iron or ductile iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal.

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). Each segment of cast-iron or ductile iron pipe on which localized graphitization is found to a degree where leakage exists or might result shall be replaced or repaired with an appropriate repair device.

General graphitization occurs as a pipe wall loss over a large area. Each segment of cast-iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or leakage exists or might result shall be replaced.

Both types of graphitization can occur on any segment of pipe.

2.3.2 Joints

Each cast-iron caulked bell and spigot joint that is exposed for any reason shall be sealed. Acceptable means of sealing are: mechanical bell joint clamps, encapsulation, or anaerobic sealants. Sealing methods shall be done in accordance with manufacturer's pressure limitations and instructions.

2.3.3 Backfilling

When routine maintenance, such as leak repairs, bell-joint clamping, or replacement of service connections, occurs on cast-iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast-iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill may be used.

2.4 Dents, Grooves, Scratches, Gouges, and Other Defects

The depth of dents, grooves, scratches, and other defects can be measured by placing a straight edge along the undisturbed contour of the pipe and measuring the deepest point of the gap. A pit depth gage will usually work for this purpose.

3. METALLIC PIPELINE EXPOSURE EXAMINATION REQUIREMENTS

GS 1410.010 "Metallic Pipeline Exposures" provides the requirements for examination of the external condition of an exposed pipeline for evidence of corrosion (or **graphitization** on cast iron) or physical damage. Additional guidance for the excavation of a pipeline is provided below.

The excavation of a leaking pipeline should be planned by using the guidance provided within GS 1714.030 "Leakage Pinpointing." As the excavation exposes the pipeline, a visual examination of the pipeline should be ongoing to determine the extent of the excavation based on the condition of the pipeline.

Once the pipeline is exposed and the original leak is repaired, perform an investigation by examining the pipeline along the entire pipeline surface (i.e. circumferentially and longitudinally) to determine the extent of corrosion and/or damage. The examination shall extend beyond the original exposed portion by means of one of the following methods.

a. Direct Examination – Expose at least 12 inches* of additional pipeline on each end of the excavation, if conditions warrant, and examine the newly exposed pipeline along the entire pipeline surface (i.e., circumferentially and longitudinally). Conditions that warrant extending the excavation include visual observations that pitting continues into the bank of the original excavation, site conditions (e.g., traffic flow, soil conditions, weather) that allow for continued safe excavation, etc. Extend the excavation* until no corrosion that requiring repair or replacement is found.

b. Indirect Method – Examine the unexposed pipeline by making sidebar holes, prior to backfilling the original excavation, at 3, 6, 9, and 12 o'clock approximate positions around the pipe as it enters the earth on both sides of the excavation and test with a combustible gas indicator for leakage.

*If the excavation continues to require extension beyond typical repair limits, consider performing spot checks along the existing pipeline to determine the extent of corrosion and/or if the pipeline segment should be a candidate for replacement. Contact local field operations leadership and/or field engineering personnel for guidance, if necessary.

If no leakage requiring repair or replacement is found, a pipe-to-soil potential measurement should be obtained. Install anode (if required), and coating according to GS 1460.010 “Corrosion Remedial Measures – Distribution,” and then backfill the excavation. If additional leakage exists, investigate according to GS 1708.070 “Outside Leak Investigation,” GS 1714.030 “Leakage Pinpointing,” and other applicable leakage gas standards.

4. ADDITIONAL REMEDIAL MEASURES FOR REPAIRS ON METALLIC PIPE

4.1 Steel Pipeline

Whenever a corrosion leak is repaired on a steel pipeline, a pipe-to-soil potential measurement (refer to GS 1430.110 “Pipe-to-Soil Potential Measurements”) should be obtained after the repair, but prior to other remedial actions being performed.

Corrosion leak repairs on steel pipeline require the installation of an anode (if the pipe-to-soil potential measurement is less negative than -1.000 V in reference to a copper-copper sulfate electrode) and the application of an approved coating.

Refer to GS 1460.010 “Corrosion Remedial Measures – Distribution” for detailed guidance.

4.2 Coated Steel Pipeline

In addition to the general requirements in Section 4.1 above, the installation of a test station is also required for corrosion leak repairs on coated steel pipeline.

Also, before a leak repair on coated steel pipeline is backfilled, field personnel should notify the local corrosion personnel so that investigative tests can be performed near or at the pipeline to help determine the root cause of the leak if the pipeline is cathodically protected.

4.3 Cast Iron or Wrought Iron

When a repair fitting is installed, apply an approved coating and install an anode, where required.

5. REPAIRS ON POLYETHYLENE AND PVC PIPES

In all cases, care must be exercised to prevent a static charge from igniting a combustible mixture of air and gas. The pipe shall be wrapped with wet soapy burlap or cotton rags or other approved static reducing material contacting the earth to protect against static charge.

When it is necessary to squeeze off polyethylene pipe, the squeeze off shall be done in a separate bellhole remote to the leak whenever possible.

Permanent repairs on polyethylene pipe that has been severed in half, gouged or punctured and is leaking, require cutting out and replacing the damaged pipe. The pipe must be isolated by operating a valve(s) or squeezed off and a pre-tested section installed using mechanical, electrofusion, socket fusion, butt fusion, or a combination of these methods.

The installation of electrically isolated metallic fittings within plastic pipelines should be avoided when possible. However, when electrically isolated metallic fittings are installed in a plastic pipeline, the installation of an anode, the installation of a test station, and the application of an approved coating is required, with the following exception. If the isolated metallic component can be bonded to an adjacent cathodic protection system, then only the application of an approved coating is required.

5.1 Working in Excavations with Blowing Gas

Because static electricity charges can build up on any non-conductor such as polyethylene and PVC pipe, there is a possibility of a spark discharge of sufficient energy to cause ignition if the proper air/gas mixture is present. It is also possible for repair crew members to receive shocks even though ignition does not occur. Before personnel are permitted in the excavation where live gas is escaping, static electricity control measures shall be applied. Refer to GS 1770.010 “Prevention of Accidental Ignition” for guidelines.

The objective is to provide a path to ground for any static discharge.

5.1.1 Temporary Repair Clamps on Polyethylene Pipe

The installation of a full encirclement stainless steel or carbon steel repair clamp as a temporary or permanent repair on polyethylene pipe is prohibited.

A full encirclement clamp may be used to slow down or eliminate gas flow to more safely enable a permanent repair or pipeline replacement to occur. However, in no case shall the installation of this clamp be buried or left unattended on an in-service pipeline.

5.1.2 Installing Squeeze-Off Units on Polyethylene Pipe

Squeezing the pipe creates an increase in velocity of flowing gas and possible increase in static charge.

Refer to GS 1680.040 “Squeeze-Off Procedure for Plastic Pipe” for guidelines.

5.2 Ten Percent Rule

Polyethylene pipe that has been gouged, nicked or cut to a depth of more than 10% of its wall thickness must be replaced. PVC pipe with the same defects may either be replaced or repaired with an all stainless steel band type clamp. Damages resulting in wall loss of less than 10% requires no remedial action.

5.3 Use of Fusion Equipment in Gaseous Atmosphere

Heat fusion tools can be used in the presence of gas provided they are unplugged from their power source. Never enter a gaseous atmosphere with a heating tool that is plugged into a generator or standard current source. Electrofusion equipment and generators are considered potential sources of ignition and shall be kept outside of any gaseous atmosphere.

5.4 Faulty Butt Fusion Joints and Cracks

Faulty butt fusion joints and cracks should be repaired by installing a new section of pipe. In some instances a faulty butt fusion can be repaired by cutting through the joint and connecting the ends with an approved mechanical or electrofusion fitting.

6. REPAIR METHODS

Approved repair methods for dents, grooves, scratches, gouges, and other defects are provided in Table 1.

Approved repair methods for various conditions in steel and wrought iron pipe are provided in Table 2.

Approved repair methods for various conditions in cast iron and ductile iron pipe are provided in Table 3.

Approved repair methods for various defects in polyethylene and PVC pipe are provided in Table 4.

TABLE 1

Repair Methods for Dents, Grooves, Scratches, Gouges, and Other Defects on Steel Pipe*	
Type of Defect	**Type of Repair**
Dent with stress concentrator such as scratch, gouge, groove or arc burn **or** Dent that affects a seam or girth weld	• Install an appropriate type bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) greater than 2% of nominal O.D. on greater than 12.75" O.D. pipe or greater than ¼" deep on pipe less than or equal to 12.75" O.D. pipe	• Install an appropriate type bolt-on clamp or sleeve **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) less than 2% of nominal O.D. on greater than12.75" O.D. pipe or less than ¼" deep on pipe less than or equal to 12.75" .D.	• Re-coat
Grooves, Scratches, Gouges, and other defects with less than 12.5% metal loss	• Recoat • Grind/Sand
Grooves, Scratches, Gouges, and other defects with 12.5% and greater metal loss	• Install an appropriate bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder

***<u>GENERAL NOTE</u>:**
See GS 1730.010 "Transmission Line Field Repair" for repair methods for Transmission Lines.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Leakage: Distribution Pipe Repair**	Standard Number: **GS 1714.020**
Supersedes: 07/01/2014		Page 9 of 11

TABLE 2

REPAIR DEVICE(S)[1] FOR STEEL OR WROUGHT IRON PIPE*			
TYPE OF DEFECT	**125 PSIG OR LESS**	**GREATER THAN 125 PSIG TO 175 PSIG**	**GREATER THAN 175 PSIG**
<u>CORROSION</u> LOCAL PITTING	BAND TYPE CLAMP or PIT HOLE CLAMP		BAND TYPE CLAMP or WELDED SPLIT SLEEVE
LENGTHY PITTING	LONG BAND TYPE CLAMP		WELDED SPLIT SLEEVE OR REPLACE
GENERAL CORROSION	MECHANICAL SPLIT SLEEVE[2] or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
<u>FAILURES</u> RUPTURE (caused by internal pressure)	REPLACE		
PUNCTURE, BREAK or TEAR (caused by external force)	BAND TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	WELDED SPLIT SLEEVE OR REPLACE
CRACK IN PIPE	MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	REPLACE
<u>JOINT FAILURES</u> COUPLING: GASKET	RETIGHTEN or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
BARREL	J TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
CRACK IN WELD	WELDED SPLIT SLEEVE OR REPLACE		
SCREW FITTING	COLLAR LEAK or PIPE JOINT TYPE CLAMP		NA
<u>OTHER</u> BAG OR PURGE HOLES	BAND TYPE CLAMP or SERVICE SADDLE	NA	
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP	WELDED SPLIT SLEEVE OR REPLACE	

*<u>GENERAL NOTES</u>:

a. The repair techniques for higher pressure steel mains are acceptable for lower operating pressure steel mains.
b. Mechanical or welded split sleeves are acceptable alternatives for any mechanical clamp device installation.
c. Refer to manufacturer's instructions for additional pressure limitations for certain repair fittings.

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[1] Non-mechanical repair devices (e.g., Trident Seal, Clock Spring, Armor Plate) may also be used subject to pressure limitations of the product and if appropriate for the application per the manufacturer's intended use of such products.

[2] Welded split sleeves may be substituted for mechanical split sleeves.

TABLE 3

TYPE OF DEFECT	REPAIR DEVICE(S) FOR CAST IRON PIPE*
GRAPHITIZATION GENERAL	REPLACE
LOCALIZED	BAND TYPE CLAMP OR REPLACE
FAILURES CRACK IN PIPE	FULL SEAL TYPE CLAMP
JOINT FAILURES COUPLING: GASKET OR BARREL	MECHANICAL SPLIT SLEEVE or ENCAPSULATION
BELL JOINT LEAK	BELL JOINT CLAMP[3], ENCAPSULATION, or ANAEROBIC GASEAL
OTHER BAG OR PURGE HOLES	BAND TYPE CLAMP

*GENERAL NOTES:

a. Mechanical split sleeves are acceptable alternatives for any mechanical clamp device installation.
b. Bell joint leak repair devices are subject to pressure limitations.The pipe may be repaired by a clamp or sleeve, provided that the repair clamp or sleeve will cover the graphitized area and the ends of the repair clamp or sleeve are over sound, non-graphitized pipe.

[3] Bell joint leak repair devices are subject to pressure limitations.

TABLE 4

REPAIR DEVICE(S) FOR POLYETHYLENE OR PVC PIPE		
TYPE OF DEFECT	**POLYETHELENE**	**PVC**
RUPTURE (caused by internal pressure)	REPLACE	
PUNCTURE, BREAK or TEAR (caused by external force)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE
CRACK IN PIPE	REPLACE	
LEAK AT FUSIONS (BUTT, SOCKET, SADDLE OR ELECTROFUSION)	REPLACE	NA
NON-LEAKING DAMAGES (deeper than 10% of wall thickness)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE

[4] Repairs on PVC pipe using an all stainless steel band clamp require the gasket to extend 2 ½ inches beyond the damage and holes must be less than one third (1/3) the pipe diameter.

NiSource
Distribution Operations

Gas Standard

Effective Date: 08/01/2010	Leakage Pinpointing	Standard Number: GS 1714.030
Supersedes: N/A		Page 1 of 3

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV ☑ CKY ☑ CMA	☑ CMD ☑ COH ☑ CPA

1. GENERAL

Pinpointing is the process of tracing a detected gas leak to its source. It follows an orderly systematic process to minimize excavation.

The shape and size of the leakage migration pattern is determined largely by the resistance of the subsurface atmosphere to gas venting from a leak. Factors influencing the leakage migration pattern can be soil conditions, main pressure, leak size, depth of cover, other facilities, and recent construction activities.

2. PROCEDURE

2.1 Establishing Leakage Perimeter

Determine the outer boundaries of the leakage migration pattern by taking CGI readings. Check against foundation walls, subsurface structures, sewers, conduits, etc. and along paved areas where gas may migrate and create hazardous accumulations. Look for evidence of recent construction activities that could contribute to the leakage. Gas may also migrate and vent along a trench.

This will define the area where the leak is normally located.

2.2 Locating Facilities

Locate all Company gas lines within the leakage migration pattern to narrow the area of the search paying particular attention to the location of valves, fittings, tees, stubs and connections due to the relatively higher probability of leakage of these facilities.

Identify other facilities within the leakage migration pattern such as sewers, tunnels, conduits, manholes, catch basins and other subsurface structures that can provide a path for the gas leak to follow.

2.3 Bar/Test Holes

Place evenly spaced holes over, and on the same side, of the suspected leaking gas line. Make all holes equal depth and diameter and down to the pipe depth where possible. Take all CGI readings at an equal depth in order to obtain accurate readings. Once the leak area is generally defined over a small area, locate additional bar holes to more closely bracket the area. When the pattern of the CGI readings has stabilized, the bar hole with the highest reading will usually pinpoint the leak.

When the leakage source is not readily apparent, one or more of the following pinpointing techniques may be used.

2.3.1 Top-of-Hole Testing

If readings in several holes are so similar that it is difficult to select the highest, remove the test probe, and place the open end of the hose flush with the top of the hole. This technique will often determine the amount of gas flowing up from a particular hole and can give an accurate indication of which hole is closest to the leak. For example, if three holes are tested with the probe at the bottom and each reads 80% while the top-of-the-hole tests read 30% in two and 80% in one, then the 80% hole is probably closest to the leak. Top-of-the-hole testing is a very helpful technique in pinpointing large volume leaks, particularly if a series of high gas readings are encountered.

2.3.2 Sight

Escaping gas fumes will be similar in appearance to heat waves above a radiator. On a sunny day, escaping gas will cause shadows on the ground or on a piece of white paper held perpendicular to the surface with the hole between the paper and the sun.

Another variation is to reflect sunlight down the hole with a mirror or throw dust into the hole and note the turbulence of the dust particles.

A soap bubble test can also be performed. A soap film drawn across a pipe/tube inserted into the hole will indicate escaping gas.

In making visual observations, the hole with the most fumes, the greatest amount of dust turbulence, or the fastest growing bubble is probably closest to the leak.

2.3.3 Feel

By placing the back of the hand or other sensitive skin surface over the hole, it is sometimes possible to feel which hole is venting the most gas.

2.3.4 Sound

In quiet conditions, the sound of gas escaping from the hole can sometimes be heard indicating which hole is venting the most gas.

2.3.5 Smell

Another useful test is odor. Gas at the point of leakage usually has a very distinctive odor that, in many instances, will be modified as it flows through the soil.

Holes from which the gas most closely smells like the original odor are normally closest to the leak.

2.3.6 Purging

To assist in making the diagnosis of the actual leak location, use a soil purger, air mover or aerator that evacuates the gas and air from individual holes and the surrounding subsurface area thus shrinking the size of the leak pattern. A purger is most helpful for accurately pinpointing a leak when there may be 90% to 100% readings in several consecutive bar holes.

It is not necessary to purge each individual bar hole because this will be accomplished automatically when a specific area is purged. The bar hole that tests positive first after all bar holes have been purged to zero and the purger shut off, is usually nearest the leak.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Leakage - Sampling of Unknown/Stray Gas	Standard Number: GS 1714.040
Supersedes: 08/01/2010		Page 1 of 9

Companies Affected:

☑ NIPSCO Effective: 01/01/2015	☑ CGV	☑ CMD
	☑ CKY	☑ COH
	☑ CMA	☑ CPA

1. GENERAL

Follow manufacturer's and lab instructions for using sample gas collection containers. Available laboratory analysis options can be found on the Gas Distribution Standards page of MySource (on the right side of the page under "General").

Gas leakage investigations can include the investigation of a combustible gas indication or odor complaint where the source and type of combustible cannot be readily determined, or where incidents have resulted in injuries or damages. This usually leads to an investigation to determine if the combustible is Company pipeline gas, or from some other source. Other unknown sources occasionally encountered include the following:

a. methane from coal mines or an organic source, such as land fills, sewers, or swamps,

b. gasoline, propane, or other product type hydrocarbons from tanks or product pipelines,

c. natural gas from wells or other pipelines, and

d. other combustible gases created from chemical reactions or burning synthetics, such as burning electrical coating.

When a laboratory analysis is required of a combustible sample, an effective sampling technique shall be used to obtain the sample to allow a laboratory to make an analysis.

CAUTION: Where a petroleum product, such as gasoline, diesel fuel, etc. is suspected, a charcoal filter or hydrocarbon absorbent type filter installed in the Combustible Gas Indicator (CGI) sample line will temporarily absorb the gasoline vapor and prevent it from affecting the CGI reading.

2. OBTAINING SAMPLES

The following techniques are effective in obtaining gas samples for analysis in connection with leakage, or stray gas investigations.

Safety Precautions: Unknown samples may contain gas mixtures in the explosive range. Take care to ensure the samples are not exposed to ignition sources, e.g., sparks, fire, etc.

2.1 Combustible Gas Indicator Method

The preferred method of taking these gas samples makes use of a Combustible Gas Indicator (CGI). The highest measurable gas samples are drawn into a container that is acceptable to the testing lab. The lab will analyze the sample obtained, but the higher the gas reading in the sample, the more likely an analysis will produce definitive results.

When the sample is drawn through a hot wire CGI using an aspirator bulb, it is important to have the CGI turned off to eliminate the possibility of a portion of the sample or the entire sample being consumed. It is also advisable to take a CGI reading both before and after the sample is taken to confirm the content of the container.

When the sample is captured on the inlet side of the hot wire CGI, or if a non-hot wire CGI is used, it is not necessary to turn the CGI off. The CGI reading should be taken while drawing the sample to confirm the content of the container.

2.2 Containers Approved for Sampling and Shipping

The type of container used for sampling gas depends upon the type of analysis required, volume of gas required for analysis, pressure restrictions of the container, shipping limitations, and lab preference (if preference is indicated). For shipping instructions, area should consult the shipping company (i.e. Federal Express, United Parcel Service).

2.3 Considerations

Consideration shall also be given to the following when taking gas samples for analysis.

a. Obtain a sample sufficient to perform an original test and a retest.

b. Use a sample probe or liquid trap filter when liquids may be present.

c. Use a clean sample container.

d. Purge the sample line before attaching to sample container.

e. When sustained readings are available, the sample container should be purged with the sample gas to ensure a representative sample.

f. When sustained readings are not available, purging of the sample container is not advisable.

2.4 Reference Samples

When an unknown gas sample is taken for analysis, a reference sample(s) from a known source(s) shall be taken and submitted with the unknown sample. This will assist in identifying the unknown gas. Reference samples can usually be obtained at a nearby meter or regulator station.

If there is more than one possible source of an unknown gas, a reference sample from all possible sources, such as foreign gas lines, gas well, etc., shall be taken.

Refer to the Company's gas standard for taking pressurized samples.

3. SHIPPING INSTRUCTIONS

Care shall be taken that gas sample containers are tightly sealed. Containers can be checked for leakage by soaping valves and fittings or by submerging in water. When transported by Company personnel, the package shall be secured to prevent damage to the gas sample container. When transported by a shipping company the sample shall be shipped according to applicable rules and regulations and the shipping company's instructions.

A best practice is to include the business card of a responsible leader in the shipping package as a point of contact should the lab have any problems or questions.

4. RECORDS

Form GS 1714.040-1 "Gas Sample Record" (see Exhibit A)shall be completed for all gas samples taken and shipped along with the sample container to the testing laboratory. A copy of Form GS 1714.040-1 shall be retained and attached to the laboratory analysis record when returned to the Operations Center or applicable department. Form GS 1714.040-1 and the laboratory analysis record shall be retained at the Operations Center or applicable department in accordance with Company document retention requirements or as directed by legal counsel.

EXHIBIT A
(1 of 6)

Instructions for completion of Form GS 1714.040-1 “Gas Sample Record."

The following items are keyed to Form GS 1714.040-1, page 6 of this exhibit. Each block must be completed, if applicable.

Key	Item	Description
1	Work/Job Order No.	Self-explanatory.
2	Related Leak Order No(s)	For unknown gas source samples, indicate number(s) of any related leak order(s) written.
3	Company	Check appropriate box.
4	Operations Center	Name (e.g., PA-Central, Chester, Heartland) or Number.
5	Number of Samples Submitted	Total number of samples submitted for this analysis. This form provides space to document up to two (2) samples. If more than two (2) samples are submitted, attach additional forms to document additional sample information, and state the total number of samples submitted on the first form.
6	Sample(s) Taken By:	List all persons involved with sample taking.
7	Date	Indicate date sample was taken.

EXHIBIT A
(2 of 6)

..8	Time	Indicate time sample was taken.
..9	Unknown Sample Location	In "Sample ID," indicate an identification number or letter to differentiate the unknown sample container from the known sample container included with this Sample Record. NOTE: Label sample containers accordingly. In "Address," indicate nearby street address and municipality name. In "Other," indicate description of where the unknown/stray gas sample was taken (e.g., manhole 30 feet south of north side property line in rear of 2759 Kent Rd., catch basin in NE corner at Front and Town Street intersection). Pressure: Indicate the approximate pressure in the sample container in psig units.
.10	Known Sample Location	In "Sample ID," indicate an identification number or letter to differentiate the known sample container from the unknown sample container included with this Sample Record. NOTE: Label sample containers accordingly. In "Address," indicate nearby street address and municipality name. Check the "NiSource" box, if the known gas sample is from NiSource Company facilities. If not NiSource Company gas, identify the other company. In "Station#," indicate the Company district regulator or POD station number if the known gas sample was taken at a Company regulator station. In "Meter#," indicate the Company meter number if the known gas sample was taken at a customer meter set assembly.

EXHIBIT A
(3 of 6)

		Pressure: Indicate the approximate pressure in the sample container in psig units.

NOTE: if more than two (2) samples are submitted, use additional forms.

11	Field Observations	Provide any information or observation that is pertinent to gas source. Examples of information which will assist in determining the source of an unknown gas sample are: sample taken in land fill area, abandoned gas well in area, septic tank in yard, etc.

CHAIN OF CUSTODY

.12	Lab Shipped To:	Indicate the name and address of the laboratory performing the analysis.
.13	By:	Indicate the name of the Company person that shipped the sample(s)
.14	Date:	Indicate the date that the sample(s) were shipped.
.15	Shipped Via:	Check the appropriate box that indicates the shipping company. If "Other," then indicate the name of the shipping company.
.16	Shipped From:	Indicate the city and state of where the sample(s) were shipped from.

EXHIBIT A
(4 of 6)

.17	Released By:	As the sample moves from person to person, each person that hands the sample(s) off to someone else shall sign and date in the “Released By: column. Print the name below the signature. (e.g., Company sample taker, Company person who shipped the sample if different from the sample taker, laboratory analysis person(s))
.18	Received By:	As the sample moves from person to person, each person that receives the sample(s) from another person shall sign and date in the “Released By: column. Print the name below the signature. (e.g., Company person is responsible for shipping the sample if different from the sample taker, laboratory analysis person(s))
19	CGI Reading	Indicate CGI reading of the sample(s) and whether % gas or LEL. For hand aspirated sample, indicate reading shown on CGI. For water displacement method, the reading indicated is that taken immediately prior to taking the sample. For pressurized sample, identify by writing in "Pressurized Sample."

EXHIBIT A
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20	Analysis Required	Indicate type of analysis. If other combustible non-hydrocarbon compounds are suspected, such as cleaning solvent, check "Other" and indicate type compound suspected. For stray gas issues, check both "Hydrocarbon and Inerts" and "Other," and indicate "Source analysis" to alert the testing lab that an interpretive report is required in addition to the raw data. Suspected other compounds can be mention in the field observations.

REPORTING

21	Report To Be Sent To	Indicate person to receive the analysis report, normally a System Operations Leader. NOTE: If injuries to a person(s) or damages to an entity other than a NiSource Company are involved, an attorney in the NiSource Law Department should be maintaining the Company's file, and that attorney should be identified in this space.

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	**Leakage - Sampling of Unknown/Stray Gas**	Standard Number: **GS 1714.040**
Supersedes: 08/01/2010		Page 9 of 9

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NiSource

GAS SAMPLE RECORD

WORK/JOB ORDER NO.____ 1 ____

RELATED LEAK ORDER NO.____ 2 ____

COMPANY: 3 ☐-CKY ☐-CMA ☐-CMD ☐-COH ☐-CPA ☐-CGV ☐-NIPSCO	
OPERATIONS CENTER: 4	**Number of Samples Submitted:** 5

SAMPLE(S) TAKEN BY: ____ 6 ____ 7 (DATE) 8 : (TIME) ☐ AM ☐ PM

UNKNOWN SAMPLE LOCATION 9 Sample ID:	KNOWN SAMPLE LOCATION 10 Sample ID:
Address:	Address:
Other:	NiSource ☐ Other:
Pressure:	Station#: Meter#: Pressure:

Field Observations:
11

CHAIN OF CUSTODY

LAB SHIPPED TO: ____ 12 ____ **BY:** ____ 13 ____ **DATE:** ____ 14 ____

SHIPPED VIA: 15

☐ **UPS** ☐ **OTHER SPECIFY:** ____ **SHIPPED FROM:** CITY: ____ 16 ____ STATE: ____

	RELEASED BY 17	DATE MM DD YY	RECEIVED BY 18	DATE MM DD YY
SIGN		/ /		/ /
PRINT				
SIGN		/ /		/ /
PRINT				
SIGN		/ /		/ /
PRINT				

INSTRUCTIONS: ALL PERSONS RELEASING AND/OR RECEIVING THIS SAMPLE MUST SIGN AND DATE THE APPROPRIATE SPACE PROVIDED ABOVE. AFTER ANALYSIS, THIS RECORD IS TO BE ATTACHED TO THE GAS SAMPLE ANALYSIS RESULTS BY THE TESTING LAB.

UNKNOWN COMBUSTIBLE GAS/AIR MIXTURE	ANALYSIS REQUIRED
CGI READING ____ 19 %GAS ____ %LEL	☐-HYDROCARBON & INERTS 20 ☐-OTHER ____

REPORTING

REPORT TO BE SENT TO: 21
NAME:
COMPANY:
ADDRESS:
CITY/STATE/ZIP:

Form GS 1714.040-1 01/2016

NiSource
Distribution Operations

Gas Standard

Effective Date: 01/01/2016	Leakage Repair Follow-Up Inspections	Standard Number: **GS 1714.060(KY)**
Supersedes: 01/01/2015		Page 1 of 3

Companies Affected:

☐ NIPSCO	☐ CGV	☐ CMD
	☑ CKY	☐ COH
	☐ CMA	☐ CPA

REFERENCE KY 807 KAR 5:006 Section 26(3)

1. GENERAL

A follow-up inspection to determine the effectiveness of cleared leaks shall be conducted using one of the following acceptable methods as listed in GS 1708.030 “Leakage Survey and Test Methods."

a. Surface Gas Detection Survey

b. Subsurface Gas Detection Survey

c. Pressure Drop Test

d. Exposed Piping Test

2. FOLLOW-UP INSPECTIONS

Follow-ups are not required for cleared leaks on above ground pipelines.

If during the follow-up inspection, no leakage is found, the follow-up order can be completed with no further action.

If during the follow-up inspection it is determined that leakage still exists, a new leak order shall be created and the two orders cross-referenced on the applicable paper documents and in the Company’s work management system.

2.1 Follow-up Inspection Requirements

2.1.1 Grade 1 Leaks

A follow-up inspection is required for the following conditions:

a. all cleared Grade 1 leaks on buried pipelines with residual gas (residual gas is defined as gas remaining in the soil after the leak is cleared and is expected to dissipate through normal means) or

b. all repaired* Grade 1 leaks on buried unprotected metallic pipelines where programmed leakage surveys are not performed at least annually.

2.1.2 Other Cleared Leaks

In areas where programmed leakage surveys are performed annually or on a greater frequency, follow-up inspections are not required.

If leakage surveys are not performed at least annually, follow-up inspections are required in the following instances:

a. a random sample of repaired* Grade 2 leaks on buried unprotected metallic pipelines in accordance with the Company's work management practices or

b. as requested by the person clearing the leak.

NOTE 1: Repaired* as used in this gas standard means a physical repair and does not include leaks cleared by replacement, abandonment, negative readings, etc.

NOTE 2: The following Cleared by Codes do not require a followup inspection: replacement or abandonment (Cleared by Codes 23, 24, 27, 28, 39, 40), negative readings (Cleared by Code 33), mistake (Cleared by Code 00), handed over to another Company or responsible person (Cleared by Codes 31, 32). Refer to applicable GS 1708.100 "Leak Control Records" for additional information on Cleared by Codes.

2.2 Frequency of Required Follow-up Inspections

2.2.1 Grade 1 Leaks with Residual Gas

Grade 1 leaks on buried pipelines with residual gas require a follow-up inspection by the last day of the next calendar month following the leak being cleared. When residual gas remains in the soil after the leak is cleared, it is recommended to wait at least 14 days before doing the follow-up inspection to allow time for the residual gas to vent out of the soil.

2.2.2 Other Cleared Leaks

All other cleared leaks on buried pipelines should have a follow-up inspection prior to the last day of the next calendar month following the leak being cleared. However, if the inspection cannot be completed within this timeframe, the Company shall document the reason for the delay and the expected time-frame to complete the follow-up inspection.

3. RECORDS

Results of a follow-up inspection shall be documented within the Company's work management system.

The date and time of the follow-up inspection shall be recorded in the electronic WMS Job Order execution remarks field.