SAFE OPERATION OF HYDROGEN, CARBON MONOXIDE, AND SYNGAS PIPELINE SYSTEMS

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SAFE OPERATION OF HYDROGEN, CARBON MONOXIDE, AND SYNGAS PIPELINE SYSTEMS

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1 Introduction

Operation and maintenance guidelines for transmission pipelines are important requirements due to the hazardous nature of certain gases and the presence of the pipelines in the public domain. This is particularly true of hydrogen, carbon monoxide, and syngas due to the flammable and/or toxic nature of the gases being transmitted.

Those involved in the safe operation and maintenance of hydrogen, carbon monoxide, and syngas gaseous transmission and distribution systems should be aware of various documents, guidance, publications, and standards prepared by various multinational organizations that can be pertinent to these systems. While the cited references provide valuable background, it cannot be stated that these are all the standards, documents, or technical papers published by international organizations that could be pertinent to the subject of this publication.

The purpose of this publication is to further the understanding of those engaged in the operation and maintenance of transmission systems. It is not intended to be a mandatory standard or code. It contains a summary of current industrial practices and is based upon the combined knowledge, experience, and practices of the major producers in Western Europe and North America.

2 Scope

This publication provides guidelines for the safe operation and maintenance of industrial gas pipeline systems for gaseous hydrogen, carbon monoxide, and syngas (mixture of hydrogen and carbon monoxide). Pipelines may cross boundaries of jurisdiction and traverse land not under the control of the pipeline operator. All applicable jurisdictional requirements shall be followed in addition to the requirements of this publication. How hydrogen, carbon monoxide, and syngas impact the integrity management programs of industrial gas pipelines in the public domain is discussed herein.

This publication applies to both active (in-service) pipelines and pipelines being considered for repurposing to hydrogen, carbon monoxide, or syngas service, and addresses operations and maintenance guidelines, with references to good design practices. Out-of-service or abandoned pipelines are not covered in this publication. However, the information contained in this publication may be applicable to those pipelines.

This publication identifies some high-level considerations for blending hydrogen into natural gas pipelines; however, this is an emerging application, and best practices and regulations are still evolving. See Section 11 for information on blending.

The applicability of this publication is limited to gaseous products with a temperature range between –40 °C and 150 °C (-40 °F and 300 °F), and pressures from 0.1 MPa up to 15 MPa[1] (14.5 psi up to 2250 psi)[2]

This publication addresses land-based pipelines and does not specifically address offshore pipelines.

This publication does not cover:

- carbon dioxide, nitrogen, oxygen, argon, helium, steam, natural gas (except as noted previously), ammonia or water;
- liquid pipelines; or
- pipelines fabricated from nonmetallic material such as plastic or composite material.

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[1] psi, bar, and MPa/kPa shall indicate gauge pressure unless otherwise noted as (psia; bar, abs; and kPa, abs) for absolute pressure or (psid; bar, dif; and kPa, dif) for differential pressure. All kPa values are rounded off per CGA P-11, *Guideline for Metric Practice in the Compressed Gas Industry* [1].

[2] References are shown by bracketed numbers and are listed in order of appearance in the reference section.

To the extent that they exist, national laws can supersede the practices included in this publication. It should be noted that not all local regulations, tests, safety procedures, or methods are included in this publication and that abnormal or unusual circumstances could warrant additional requirements.
This publication does not apply to the following processes or systems:

- cylinder filling plants;
- production plants;
- compressor units;
- bulk facilities (liquid or high pressure gas) at the customer's site up to the point where gas enters the distribution systems; or
- piping on specialized equipment and machines.

These systems have many specialized needs and requirements. However, this publication may provide useful background information for other processes where hydrogen, carbon monoxide, or syngas are present.

3 Definitions

For the purpose of this publication, the following definitions apply.

3.1 Publication terminology

3.1.1 Shall

Indicates that the procedure is mandatory. It is used wherever the criterion for conformance to specific recommendations allows no deviation.

3.1.2 Should

Indicates that a procedure is recommended.

3.1.3 May

Indicates that the procedure is optional.

3.1.4 Will

Is used only to indicate the future, not a degree of requirement.

3.1.5 Can

Indicates a possibility or ability.

3.2 Technical definitions

3.2.1 Active pipeline

Pipeline under pressure and is flowing product.

3.2.2 In-service pipeline

Pipeline that is either in the process of delivering, or is ready to deliver material to a downstream user or users.

3.2.3 Lower flammable limit (LFL)

Minimum concentration in air of a gas that would burn when ignited.

NOTE—Also known as the lower explosive limit (LEL).

3.2.4 Maximum allowable operating pressure (MAOP)

Maximum internal pressure permitted during the operation of a pipeline.

3.2.5 Pig

Tools used for the routine cleaning, maintenance, and inspection of pipelines.

3.2.6 Pipeline operator

Entity responsible for the safe and efficient operation of pipelines that transport hydrogen, carbon monoxide, or syngas products.

3.2.7 Pressure purge

Process by which gaseous material is introduced to a pipeline or pipeline equipment in order to dilute and safely remove previously contained material from the pipeline or pipeline equipment.

3.2.8 Pressure relief device (PRD)

Device installed in pressurized equipment or integrated with a valve that will release the contained gas in specific conditions.

NOTE—PRDs can be activated by excessive temperature, excessive internal pressure, or both.

3.2.9 Risk assessment

Documented exercise to assess the risks of a specific operation to personnel and the environment. This process usually takes into account safety controls inherent in equipment, operating procedures, and personal protective equipment (PPE) provided. Sometimes it may be deemed appropriate to improve operational safety controls after undertaking a risk assessment.

3.2.10 Station/Metering station

Area within which a pipeline product's flow rate and composition are measured.

3.2.11 Syngas

Mixture primarily of hydrogen and carbon monoxide with a very low dew point that can also contain significant but lower concentrations of methane and carbon dioxide as well as smaller amounts of impurities such as chlorides, sulfur compounds, and heavier hydrocarbons.

NOTE—Syngas is also referred to as “oxogas.”

3.2.12 Transmission pipeline

Pipeline used to safely transport hydrogen, carbon monoxide, and syngas from suppliers to customers. A transmission pipeline usually operates at higher pressure and has a larger diameter than distribution pipelines.

3.2.13 Upper flammable limit (UFL)

Maximum concentration in air of a gas that would burn when ignited.

NOTE—Also known as the upper explosive limit (UEL).

4 General safety considerations

The safe operation of a pipeline system depends on various factors, including the properties of the fluid being transported. This section describes the principal risks and hazards associated with hydrogen, carbon monoxide, and syngas systems and how to mitigate those hazards. This section also provides guidance on general protective measures and electrical hazardous area requirements for hydrogen, carbon monoxide, and syngas pipelines.

4.1 Properties of hydrogen, carbon monoxide, and syngas

4.1.1 Hydrogen

Hydrogen is lighter than air, highly flammable, easily ignited, heats up when reduced in pressure, does not support breathing, and is one of the most difficult gases to prevent from leaking. In the pure state, it presents some unique corrosion mechanisms, and when combined with even small impurities (ppm), corrosion concerns can multiply.

Hydrogen is a flammable gas that burns with an almost invisible blueish flame in daylight and an orange flame at night. The lower and upper flammability limits (LFL and UFL) of hydrogen in air at atmospheric pressure are 4% and 75%, respectively. Hydrogen fires are concentrated, rapid, and only slightly radiative compared to hydrocarbon fires.

Although autoignition of leaks and atmospheric vents is always a possibility with any flammable gas, hydrogen is especially susceptible to this phenomenon due to hydrogen's very low ignition energy and wide flammability range. This tendency towards autoignition of leaks and atmospheric vents, combined with the difficulty in seeing the flame, makes small leaks a potentially serious personnel injury risk. See ANSI/CGA G-5, *Hydrogen*, for more information on the physical and chemical properties of hydrogen and its proper handling and use [2].

All the precautions necessary for the safe handling of a flammable gas shall be observed with hydrogen. To mitigate fire risks, fire prevention practices and operator training shall be implemented.

4.1.2 Carbon monoxide

Carbon monoxide is a flammable gas that is slightly less dense than air. Ignited in air, it burns with a blue flame and generates carbon dioxide. The flammability limits (LFL and UFL) in air at atmospheric pressure are 12.5% and 74%, respectively.

To mitigate fire risks, fire prevention practices and operator training shall be implemented.

In addition to being flammable, carbon monoxide is a toxic gas. It quickly fixes on hemoglobin causing a decrease in cellular respiration, which is harmful to the central nervous system.

The consequences of exposure to higher concentrations are given in the CGA *Handbook of Compressed Gases* [3]. Guidelines for threshold limit values for carbon monoxide in the work environment are provided by the American Conference of Governmental Industrial Hygienists (ACGIH) [4].

To prevent harm to individuals from overexposure, the general safety precautions according to 4.3 shall be observed. The following measures shall be considered:

- Personal carbon monoxide detection device worn by all personnel;

- Permanent carbon monoxide detection and monitoring in metering stations and isolation stations; and
- Leak detection system (LDS) on pipeline.

In addition to its toxicity, carbon monoxide is subject to dangerous chemical reactions. In contact with certain metals, it can create volatile metal carbonyls. The presence of water in combination with carbon monoxide in pipelines introduces serious corrosion issues that are not addressed in this publication.

4.1.3 Syngas

Within the scope of this publication, there are many similarities between hydrogen and carbon monoxide, as well as some important differences (e.g., the high flammability of hydrogen and the toxicity of carbon monoxide). The safe practices for syngas are a combination of those for hydrogen and carbon monoxide since syngas contains both in significant proportions. In practice, this means that the more restrictive of both the hydrogen and carbon monoxide requirements apply.

To accommodate this, it is helpful to set thresholds on hydrogen and carbon monoxide mixtures beyond which they are considered syngas. In general, streams with greater than 10 % hydrogen and greater than 200 ppm carbon monoxide (balance inerts and/or methane) can be considered syngas, although in practice, syngas typically contains a much higher level of carbon monoxide.

As with carbon monoxide pipelines, it is particularly important to exclude water from pipelines in syngas service, since the presence of water introduces serious corrosion issues, which are not addressed in this publication. To eliminate the risk of internal corrosion mechanisms due to moisture, syngas or carbon monoxide distributed in a pipeline shall have a water dew point low enough that condensation is not predicted to occur even in the most extreme foreseeable winter conditions. Sufficient margin shall be applied (e.g., 14°C (25°F) to account for uncertainty in operation and conditions

4.2 Carbonyls

Iron and nickel carbonyls are formed by the action of carbon monoxide upon alloys that contain iron and nickel. The longer the residence time of the carbon monoxide or syngas in the pipeline, the higher the concentration of carbonyl that can be formed. The partial pressure of the carbon monoxide also influences the rate of carbonyl formation.

Generally, carbonyl formation reaction rates are low enough that pipeline structural integrity is not affected even after long-term service (see J. Brynestad, *Iron and Nickel Carbonyl Formation in Steel Pipes and Its Prevention – Literature Survey*) [5]. Using stainless steels limits the formation of iron carbonyls, as a chromium content equal to or greater than 13% mitigates carbonyl formation. However, special attention is required for using stainless steel for syngas service, because hydrogen influences the rate of reaction of carbon monoxide and nickel to form nickel carbonyl.

Iron carbonyl is a toxic substance, and nickel carbonyl is a highly toxic substance. The U.S. Occupational Safety and Health Administration's (OSHA) permissible exposure limit (PEL) for nickel carbonyl is 0.001 ppmv on an 8-hour time-weighted average basis. The OSHA PEL for iron carbonyl is 0.1 ppmv on an 8-hour time-weighted average basis. Regulatory exposure limits can vary by jurisdiction, and the appropriate guidance documents should be consulted. There can also be limits of carbonyls based on product specifications.

4.3 General personnel protective measures

When operating a hydrogen, carbon monoxide, or syngas pipeline, the following protective measures should be employed. When conducting maintenance or repair, these measures typically are mandatory, and additional measures could be required depending on the maintenance or repair task (see 11.1).

- Smoking and other sources of ignition are forbidden in stations and within a minimum distance of 15 ft (5 m);

- Wear PPE, including flame-retardant clothing;
- Wear portable personal gas monitors:
    - Personal monitors can be configured to detect a single gas (e.g., carbon monoxide), or can be multi-sensor monitors (e.g., oxygen, carbon monoxide, flammability) and shall be selected based on the product in the pipeline and potential hazards that could be present in an area.
    - Personal monitors should be fastened to clothing near the breathing zone in accordance with manufacture guidelines. Title 29 of the U.S. *Code of Federal Regulations* (29 CFR) Part 1910.120 provides the general recommendation to fasten the monitor in a hemisphere forward of the shoulders with a radius of 6 to 9 inches [6]; and
- Provide emergency escape breathing apparatus in congested work areas.

4.4 Electrical hazardous area requirements

Electrical equipment that exists in a location where flammable process materials could be present shall comply with the requirements of NFPA 70®, *National Electrical Code*® (NEC), Article 500 – Hazardous Classified Locations, CSA C22.1, *Canadian Electrical Code*, or ATEX Directive 2014/34/EU, *Equipment for potentially explosive atmospheres* [7, 8, 9]. Article 500 covers the requirements for classification of hazardous locations (e.g., a Metering Station, flanged joint, release point) as well as the necessary mitigations to prevent the ignition of flammable materials by the electrical equipment that is present.

Electrical equipment installed in such classified locations shall be specially designed and tested to ensure it does not initiate an explosion due to arcing contacts or high surface temperature of equipment. Electrical equipment installed in a classified location (including instruments) shall be rated for the specific classification.

5 Process safety management

The risks associated with hydrogen, carbon monoxide, and syngas pipeline operation are serious enough that they should be managed with a holistic and systematic approach to ensure the integrity of the pipeline and the safety of the operating staff and public. To that end, a management system shall be in place; and federal, state, provincial/territorial, and local regulations shall be followed. Because pipelines often go through the public domain, there are strict requirements on documentation and notifications, including interactions with third parties.

See CGA P-8.10, *Industrial Gas Pipeline Integrity Management*, for more information [10].

5.1 Management systems

A management system shall be established and implemented with the objectives of ensuring the following:

- safe operation of the pipeline system;
- compliance with design;
- managing pipeline integrity;
- safe and effective execution of maintenance, modifications, and abandonment; and
- dealing effectively with incidents and emergencies.

The management system should include the following:

- identification of personnel responsible for the management of the operation and maintenance of the pipeline and for key activities (see Appendix A);
- appropriate organization chart;

- written plan covering operation and maintenance procedures;
- written control room management plan;
- written emergency response plan covering failure of pipeline systems and other incidents;
- written safe work permit system;
- written management of change process;
- written operator training and qualification program;
- periodic review and update process; and
- effective pipeline integrity management system.

Although pipelines are outside the scope of the OSHA Process Safety Management Regulations (PSM), 29 CFR Part 1910.119, CSA Z767, *Process safety management* in Canada*,* or in Europe, Seveso III Directive 2012/18/EU, the intent behind the regulations applies equally to pipelines: safety leadership, risk identification and assessment, risk management, and review and improvement [6, 11,12]. CGA P-86, *Guideline for Process Safety Management* introduces a framework that may be adopted to manage process or pipeline safety risks, although it's possible that not all process safety management elements in CGA P-86 apply, since pipeline risks may be managed by following national and international codes [13]. In addition, API RP 1173, *Pipeline Safety Management Systems* is a recommended practice (RP) to establish a pipeline safety management systems (PSMS) framework for organizations that operate hazardous liquids and gas pipelines jurisdictional to the U.S. Department of Transportation (DOT). This RP provides pipeline operators with safety management system requirements.

5.1.1 Personnel for operation and maintenance

Personnel who operate, maintain, and repair hydrogen, carbon monoxide or syngas systems shall have knowledge of the potential hazards associated with these gases. They shall know the location of the pipelines, the stations, and the control equipment. A process shall be in place to evaluate, select, and train personnel and to confirm their competency for the role's requirements.

Some specific duties of pipeline operations personnel may include:

- monitoring pressure, temperature, and composition of pipeline materials, usually from a console in a control room;
- responding to alarms and making adjustments to control pipeline conditions;
- coordinating emergency response;
- conducting routine field inspections and safety checks of pipelines and equipment;
- identifying maintenance needs; and
- recordkeeping.

All personnel, including contractors, shall be made aware of any abnormal operating conditions and have access to all relevant safety information.

5.1.2 Operations and maintenance manuals

Operations and maintenance manuals shall be provided for the operation of all hydrogen, carbon monoxide, and syngas pipelines. The operator shall provide all information needed for the safe operation of the pipeline in the form of rules, guidelines, and procedures within this document.

The pipeline system can be influenced by the reliability of the individual components and the experience and training of the operations personnel. To meet performance standards, the following shall be addressed in the manual:

- safe operation of the pipeline system;
- condition monitoring;
- safe and effective maintenance; and
- response to incidents and emergencies.

5.1.3 Control room management

Pipelines and pipeline networks typically are monitored continuously from a control room via a Supervisory Control and Data Acquisition (SCADA) system. Pipeline controllers operate the pipeline or network from the control room, and federal, state, provincial/territorial, and local typically dictate their monitoring and management requirements. Responsibilities of pipeline controllers include:

- monitoring pressure and flow of all pipeline segments;
- adjusting pressures and flows based on customer requirements;
- coordinating pipeline maintenance;
- responding to abnormal operating conditions; and
- responding to public notifications/alerts/queries and taking appropriate action

Since hydrogen, carbon monoxide, and syngas are flammable and/or toxic, developing procedures for pipeline control room management typically is a legal requirement. In the United States, hydrogen, carbon monoxide, and syngas pipeline control rooms fall under the DOT in Title 49 of the U.S. *Code of Federal Regulations* (49 CFR) Part 192.631 *Control Room Management*, and in Canada, CSA Z662, *Oil and gas pipeline systems* which specifies that procedures shall be developed to address the following elements of pipeline safety [14, 15]:

- Roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. This includes addressing shift turnover to ensure handover of responsibility between controllers at shift change;
- Information, tools, processes, and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined;
- Fatigue mitigation, as fatigue can inhibit a controller's ability to carry out the roles and responsibilities the operator has defined;
- Alarm management to provide for effective controller response to alarms;
- Change management to ensure that changes that can affect control room operations are coordinated with the control room personnel;
- Operating experience to ensure that lessons learned from operating experience are incorporated, as appropriate, into the control room management procedures; and
- Training to ensure that each controller can carry out the roles and responsibilities defined by the operator.

API RP 1168, *Pipeline Control Room Management* provides guidance on developing a control room management program that addresses the elements identified in 49 CFR 192.631 and CSA Z662 [16, 14, 15].

Access to the control room should be restricted to authorized personnel only.

In the United States and Canada, operators can be required to submit their control room management procedures to the relevant agency, and records of compliance and deviation shall be maintained for review during agency inspections.

5.1.4 Emergency planning

An emergency plan is prepared so that any incident can receive an effective response. This plan is specific to the pipeline and defines the roles of both the pipeline operator and external first responders in an emergency. It also identifies any emergency contacts, both internal and external, to the operating company. The emergency plan shall consider the response time to potential events. The emergency plan shall be distributed to third parties as required by applicable jurisdictions.

Emergency response plans should be distributed to local first responders and periodic joint drills should be considered. Training local first responders on the specific hazards and effective emergency response measures of hydrogen, carbon monoxide, and syngas should be considered.

Personnel who could be called on to respond to an incident shall receive training appropriate to their role in such an event. Any PPE that might be required is kept readily accessible and is maintained in a fit condition for use.

5.1.5 Safe work permit system

The execution of maintenance and other work activities, if not appropriately managed, can increase risk to personnel and the public. An effective work control and permit-to-work system shall be developed, documented, and followed to control the risks arising from work activities. For more information, see CGA P-86 (Element 17) and EIGA Doc 40, *Work Permit Systems* [13, 17].

5.1.6 Management of change process

Any change introduced into an organization or system, whether temporary or permanent, can introduce additional risk. An effective management of change process shall be developed, documented, and followed to control the risks arising from changes in the organization or pipeline system. The management of change process should ensure that risks arising from any form of change are systematically identified, assessed, and managed. For more information, see:

- CGA P-86 (Element 12) [13];
- EIGA HF 10, *Organisation – "Managing Organisational Change*" [18];
- EIGA Doc 51, *Management of Change* [19];
- ISO 45001, *Occupational health and safety management systems—Requirements with guidance for use* [20]; and

  NOTE—ISO 45001 provides requirements with guidance for use. Clause 8.1.3 covers management of change [20].

- CCPS *Guidelines for the Management of Change for Process Safety* [21].

5.1.7 Pre-startup safety review

Recommissioning a pipeline following a shutdown, maintenance, or repair is a potentially high-risk operation. Management shall ensure that there is a documented, systematic process for checking operational readiness and the integrity of systems before they are brought into service or returned to normal operation. For more information, see CGA P-86 (Element 13) [13].

5.1.8 Audit, review, and update

Regular review and audit of the effective application of the safety management framework is vital to ensure that safety performance continues to meet the defined targets. Management should ensure that there is both routine review and independent audit of each element of the safety management system. For more information, see CGA P-86 (Element 20) [13].

5.2 Hazard identification and mitigation

Before construction of a pipeline, a risk assessment is performed to ensure the risks to people, property, and the environment are kept within tolerable limits and minimized to the extent practical. A similar assessment shall be conducted if the environment around the pipeline changes, or if the system is significantly modified.

Some of the hazards that should be considered are:

- damage by third parties;
- damage mechanisms described in Appendix B;
- external corrosion due to improper cathodic protection;
- leaks at valve packing and gaskets;
- overpressurization of the pipeline;
- improper inerting procedure;
- improper gas inventorying procedure;
- improper operation and maintenance of the pipeline;
- abnormal loads due to landslides, floods, earthquakes, crossing of roads, railways;
- influence of other structures such as high voltage electrical lines or electrical railways;
- damage due to an abnormal event on a parallel pipe; and
- road accident or fire near aboveground parts of the pipeline.

When conducting an analysis, both catastrophic ruptures and leaks consistent with the hazard being evaluated are typically considered. The typical consequence of these events is a release of hydrogen, carbon monoxide, and/or syngas, which ignites immediately or disperses in the open air, possibly with delayed ignition. Consequences of both immediate ignition (radiation from a jet fire) and delayed ignition (blast, flash fire, and radiation) shall be assessed. See API RP 581, *Risk Based Inspection (Methodology)*, for additional information [22].

Depending on the change introduced, some of the mitigations that may be employed include:

- control of third-party interference;
- increased thickness of the pipe;
- pipeline marking;
- isolation valves;
- excess flow or low pressure shutdown valves;
- leak detection system;

- physical protections such as concrete coating or casing and concrete slabs; and
- operating procedures including inspection programs, corrosion control programs, emergency plan, personnel training, information of third parties, and collaboration with local authorities.

For carbon monoxide and syngas, the additional consequence of a release is the formation of a toxic cloud in the vicinity. The impact of toxicity shall be assessed.

5.3 Security and access limitation

Much of a pipeline could be underground, but sections where instrumentation or equipment exist typically are aboveground to allow for maintenance access. When the aboveground sections are in the public domain, appropriate measures should be taken to control access to the site and ensure that the measures taken to mitigate the risk of deliberate or accidental damage are maintained.

Measures typically used for the control of third-party interference are:

- Marker posts on the pipeline route;
- Distribution of “as built” drawings and information on the pipeline route to landowners, local authority planners, and other interested parties (e.g., railway, mining authorities, road authorities, and fire and police departments);
- Distribution of similar information to “one call” systems, a single point of contact where information on all pipelines and services can be obtained (where applicable); and
- Scheduled patrols of the pipeline by foot or aerial survey to search for unauthorized interference, or encroachment and to identify abnormal conditions (see Appendix A).

For underground piping, federal, state, provincial/territorial, and local regulations typically require that:

- Operators of underground structures (pipes, cables, etc.) submit a declaration to the local authorities concerned;
- Contractors performing excavations in the area of underground structures inform the operators of those underground structures, in the form of a declaration, about the nature of such work before starting any work;
- Operators respond to contractors in a timely manner; and
- Operators have a qualified inspector present during any third-party excavations over, adjacent to, or under its underground structures at all times while the work is being performed.

In the absence of federal, state, provincial/territorial, or local regulations, a similar plan for notifications should be adopted.

5.4 Documentation

The pipeline operator maintains a pipeline dossier that includes documents related to the construction, operation, and maintenance of the pipeline: organization and personnel, hazard identification and evaluation, operational control, management of change, planning for emergencies, monitoring performance, maintaining records, and audit/review. Updates to pipeline documents, in particular pipe installation drawings or maps, should be carried out on existing pipelines to reflect deviations and modifications that occurred when work was performed. All pipeline changes shall be managed through the pipeline management of change (MOC) process. Other requirements are dictated by local and national jurisdictions.

The pipeline dossier should also include reports of any pipeline incidents. If a pipeline incident occurs, a thorough investigation should take place, and a clear and concise report issued. Incident reporting is normally included in the legislative requirements of federal, state, provincial/territorial, or local authorities. The report should contain an accurate description of the conditions that existed during the last minutes before the incident, the material involved, and the consequences of the incident such as a secondary ignition, injury to people, and damage to equipment or property. For serious incidents, a root cause analysis should be conducted to determine what should be changed to prevent a similar occurrence.

The pipeline operator should keep the following records associated with third-party interactions:

- Requests from contractors;
- Replies to those requests, with the transmitted documents preferably including global positioning system (GPS) coordinates of the work;
- Work supervision documentation;
- A summary of work carried out on pipelines or near pipelines and of work planned but not yet performed should be made by the pipeline operator; and
- When work is performed adjacent to pipelines, the summary should be formalized by the issuance of a written document countersigned by the site manager.

6 Pipeline systems

The key requirements for maintaining the integrity of any pipeline system are similar irrespective of the fluid within, however, as already identified, there are specific principles that should be considered for hydrogen, carbon monoxide, and syngas pipelines. This section describes these principles such as electrical continuity, identification, and corrosion protection.

6.1 Underground pipeline systems

Underground pipeline systems shall follow good mechanical design practices as applied to any other underground piping system. Due to the possibility of leaks and difficulty to maintain, it is preferable not to have flanged or other mechanical joints underground. If this cannot be avoided, then the number should be limited, and they should be installed in a way that provides access for inspection, joint separation and maintenance, e.g., in valve pits.

Underground piping is vulnerable to damage by lightning strikes, ground fault conditions, or stray/induced currents which can damage/rupture the pipe material. To reduce the likelihood of these occurring, surge protection measures are used.

Aboveground portions of pipeline systems should connect to underground portions through an electrically insulated joint to isolate the underground cathodic protection system. Care should be given to the part of the pipeline between the insulating joint and the underground system. To have an effective cathodic protection there should be conduction of the current. The intermittent presence of water in casings (due to fluctuating groundwater, for example) makes the cathodic protection insufficient, and the corrosion protection solely relies on the quality of the coating.

6.2 Aboveground pipeline systems

Aboveground pipeline systems shall follow good mechanical design practices as applied to any other aboveground piping system. Due to toxicity, leakage is a greater concern for carbon monoxide and syngas than hydrogen, even though hydrogen is more prone to leakage problems than other gases due to its small molecular size. The use of welded connections is strongly recommended whenever possible. Aboveground piping should be coated to an approved specification to protect against atmospheric corrosion.

All aboveground pipelines shall have electrical continuity across all connections except insulation flanges and shall be earthed at suitable intervals to protect against the effects of lightning and static electricity.

Flange bolting provides the necessary electrical bond provided the bolts are not coated with a dielectric material or paint and are well maintained to avoid rust.

In the case of short aboveground sections where insulating flanges are not used, the pipe should be insulated from the support structure by means of an isolating pad.

Above ground pipelines should not be exposed to external forces that can cause a failure or dangerous situation such as external impingement from hot gas or steam vents, vibration from external sources, or leaking oil dripping onto the line, etc.

6.3 Pipeline identifiers

Aboveground piping should be color-coded, identified, or both. Underground piping should be identified with markers placed on the ground near the buried pipeline. Markers should be suitably spaced to indicate the route of the line. See ASME A13.1, *Scheme for the Identification of Piping Systems* for more information on piping identification and marker placement [23].

7 Pipelines and piping components

In addition to the pipeline itself, other typical components of a pipeline system include:

- Pressure-reducing control valve(s) or regulators for flow and pressure control functions;
- Flow measuring devices and other instrumentation. Flow measuring devices can include instrumentation for converting the output from the primary device into a mass flow (e.g., pressure transmitter, temperature transmitter, differential pressure transmitter, mass flow computer);
- Strainers and filters to protect control or metering devices or other pipeline equipment (e.g., compressors) from particulates carried with the gas;
- Purge/vent connections to enable purging in and out of service before and after maintenance;
- Check valves to prevent backflow from a downstream section of the pipeline to an upstream section;
- Isolation valves to isolate portions of the pipeline in emergencies or for routine maintenance and inspection;
- Flanges, which enable line breaking where needed;
- Overpressure protection, which can consist of a pressure relief valve, rupture pin device, or an instrumented protection system (e.g., pressure monitoring with automatic isolation);
- Emergency isolation valves (manual and/or automatic) to provide a means to block flow for inspection, maintenance, or risk management;
- Excess flow valves, which block flow automatically on detection of high flow indicative of a pipeline rupture; and
- Compressors (boosters or recompression) to boost the pressure from a low pressure pipeline segment to a higher pressure segment or to recompress the product at the end of a pipeline for delivery to a customer.

At a minimum, a pipeline system will include metering and control equipment that can be located at the production plant, the customer site, or both. Equipment located at the plant site typically will be maintained as part of the plant maintenance program, while the pipeline maintenance program will cover other equipment associated with the pipeline system.

Because flow metering and pressure control devices require periodic maintenance, they are constructed as a metering and/or control station (or pipeline station), which consists of isolation valves and any other components the operator deems required for operation or maintenance. Figure 1 illustrates a combined metering and control station. Note that not all the components in Figure 1 are used or required in all cases.

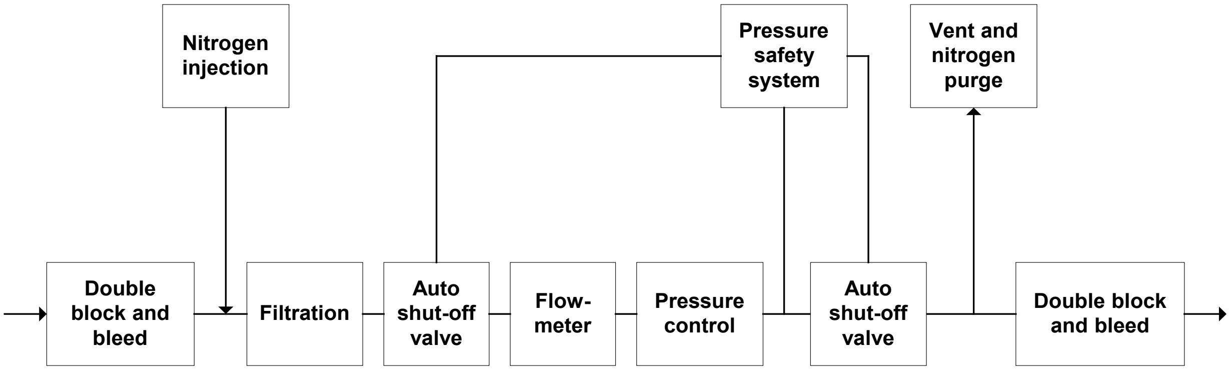

Figure 1—Pipeline station for metering and control showing typical components

Chapter 3 of ASME B31.8, *Gas Transmission and Distribution Piping Systems* provides the requirements for piping system components (excluding piping), including fabrication details [24]. The chapter covers the specifications for and selection of all components that are part of the piping system, other than the pipe itself. This includes valves and pressure reducing devices, flanges, bolting, gaskets, as well as fittings other than valves and flanges.

7.1 Hydrogen, carbon monoxide, and syngas impact on piping components

Hydrogen, carbon monoxide, and syngas may require specific considerations on piping components based on the following characteristics:

- high flammability of hydrogen, carbon monoxide, and syngas, specifically hydrogen and hydrogen mixtures;
- high toxicity of carbon monoxide and carbon monoxide mixtures;
- increased chance of leakage from hydrogen and hydrogen mixtures due to the small molecule size;
- high sonic velocity of hydrogen and hydrogen mixtures; and
- risk of hydrogen embrittlement.

The pipeline components in hydrogen, carbon monoxide, and syngas service thus need to be selected or designed to address those hazards and concerns. The following are some specific examples to be considered:

- To reduce the chance of valve leakage either to atmosphere or across the valve:
  - Use double packing or bellow seal valves
  - Use live loaded bolted packing
  - Use soft seat in a metal retainer, with bubble-tight shutoff for in-line automatic valves and automatic vents
  - Valves one inch and larger shall have welded or flanged body joints. With the exception of drain/vent plugs, threaded connections shall be avoided;
- Valve seats/plugs and similar components should consider hardened components due to hydrogen high sonic velocity;

- If the pipeline gas will contain any amount of hydrogen, the strength and hardness of all piping components should be assessed to reduce the likelihood of hydrogen embrittlement. See API 571, *Corrosion and Materials* [25];
- Pressure relief devices should consider the factors identified in 8.2. Rupture disks should not be used for hydrogen, carbon monoxide or syngas services;
- Insulating joints should be reviewed for suitability;
- Flexible connections should not be used due to potential for leaks. Expansion loops are the preferred method for providing flexibility to the piping system;
- Regulators should not vent to the atmosphere in an uncontrolled way. They should either vent internally or the vents should be handled as in 8.2; and

  Strainers and filters are recommended, especially upstream of pressure control and metering stations for hydrogen services due to the high sonic velocity.

8 Operation, monitoring, and online maintenance

It is important to ensure that the pipeline is appropriately controlled. A control strategy is established to ensure the pipeline supply remains within safe operating limits. Variables incorporated into the control strategy can include:

- Pressure—to ensure that the required delivery pressure from the pipeline is maintained;
- Flow—to match product flow into the pipeline to customer demand;
- Product purity—to ensure any product entering the pipeline system meets specifications; and
- Temperature—to ensure that cryogenic fluids (hydrogen or carbon monoxide) from the storage units do not enter the pipeline system (e.g., associated with the liquid backup on a smaller pipeline).

Any product disposal needed to maintain the required pipeline conditions is preferably achieved through controlled venting on the production site.

Supplier and manufacturer instructions for the equipment and systems shall be followed as received from the supplier or as upgraded by an authorized person in the operating company.

The instrumentation and controls associated with pipelines shall be part of the pipeline maintenance program.

8.1 Alarm and shutdown philosophy

The pipeline shall include suitable instrumentation to monitor the operating conditions and shall be configured with alarms and shutdowns to keep the pipeline within safe operating limits. An alarm and trip summary shall be provided, listing the setpoints of all alarms and trips/shutdowns. This summary may include a column that documents the basis for the alarm/trip setpoint. The alarm and trip summary may be documented within the SCADA system, but updates to either/both (table or SCADA) shall be managed via MOC.

The shutdown may be manual or automatic. Shutdown devices (e.g., emergency shutoff valves) may be triggered by a leak detection system or by sensing high flow, low pressure, or rate of decay of pipeline pressure, sometimes with a time delay to allow for operator intervention.

8.2 Venting considerations

When not prohibited by local regulation, very large flows of hydrogen gas can be vented directly to atmosphere at a safe outdoor location. When large quantities of hydrogen need to be vented to atmosphere, it is recommended to first perform thermal radiation and dispersion studies to guide the vent design. Along the length of the pipeline, it is most common to vent to atmosphere since a flare is not usually available. However, venting to atmosphere is also acceptable where a flare system is available if it presents advantages and is not prohibited.

Hydrogen vents shall be collected and routed either individually or in manifolded headers to a vent stack discharging outdoors in a location and direction that avoids impingement of escaping gas on adjacent equipment, structures, or personnel. The exit should allow the hydrogen to flow easily out to atmosphere, minimize water ingress from the environment, discourage creatures from entering, and provide quick dissipation of the hydrogen into the atmosphere. To minimize the possibility of autoignition when the hydrogen leaves the stack, the piping immediately upstream of the exit should be made either of stainless steel or a nonsparking metallic material.

.Unlike hydrogen, the venting of carbon monoxide or syngas is not allowed, except in very small amounts, such as from filters, if directed to a safe location. All other releases of carbon monoxide or syngas, such as from pressure relief valves, shall be flared to ensure that the gas does not present a toxic hazard. Portable flares can be used for depressurizing carbon monoxide and syngas pipelines.

8.3 Leakage surveys

Pipelines for toxic gases such as carbon monoxide and syngas can present high risks in the event of leaks, and hydrogen is more prone to leakage than other gases. Therefore, it is particularly important to examine these pipelines periodically with a leak detector.

The exact regimen for performing this examination varies with the population density in the area and national , state, provincial/territorial, and local regulations. Particular attention should be paid to known leak prone areas such as flanged connections and other piping components.

8.4 Leak detection systems

For a pipeline in the public domain the hazard assessment may have determined that a leak detection system (LDS) be present as mitigation for the risk of leaks. Such a system can detect a leak in real time and can estimate the size and location of the leak, which allows operations staff to assess the severity of the leak and the type of response that is required.

Automatic leak detection systems monitor continuously for leaks via dynamic flow analysis or other means. The system employed should consider the speed of leak detection required for a given leak size to achieve the overall response time required to avoid a serious incident.

When operating a hydrogen, carbon monoxide, or syngas pipeline equipped with a continuous leak detection system, it is important to check periodically that the system is on-line and operational. Automatic leak detection systems can be configured with a “heartbeat” alarm to provide a warning to the operator if communication is lost.

Any change in the pipeline system requires a new validation of the leak detection system.

8.5 In service maintenance

Pipelines and stations shall be kept in good working order from an operational and safety point of view. The operator shall follow a defined maintenance program including all safety and technical monitoring measures. A detailed description of the work to be carried out shall be documented by outlining specific tasks routinely used for pipeline maintenance. All components of the pipeline system (see Section 5) could fall under the pipeline maintenance program.

In service maintenance includes visual inspection as well as instrumentation checks, valve checks, filter cleaning, etc. Depending on the isolation valves and backup protection available, pressure relief devices may be removed and tested/overhauled while the pipeline is in service. An example of a preventive maintenance program listing some of the required tasks is given in Appendix A. The frequency of inspections is dictated by federal, state, provincial/territorial, and local regulations and/or established company practices.

8.5.1 Specialized surveys

In addition to the routine monitoring of cathodic protection system potentials, consideration should be given to monitoring the integrity of the pipeline coating system and investigating other faults, that can reduce the effectiveness of the cathodic protection system. This can be achieved by the use of specialized survey techniques such as:

- Pearson survey;
- Current attenuation survey;
- Close interval potential survey; and
- Direct current voltage gradient.

These investigations can be undertaken at 5-year to 10-year intervals depending on the pipeline and the type of cathodic protection system applied. It is common practice to compare the results of such surveys with the previous survey and with those obtained immediately following installation, see ANSI/NACE RP0502, *Pipeline External Corrosion Direct Assessment Methodology* [26].

8.5.2 Overpressure protection

Federal, state, provincial/territorial, and local regulations govern the inspection intervals for pressure relief devices and instrumented protection devices. These requirements shall be strictly followed.

9 Integrity management program considerations

One of the primary goals of any pipeline system operator is the safe and reliable continuous operation of the pipeline to deliver industrial gas to customers without interruptions and adverse effects on employees, the public, or the environment. Achieving this requires the implementation of an effective integrity management program, the goals of which are to prevent, detect, and mitigate risks by reducing either the probability or the consequences of incidents, or both. The required elements of a pipeline integrity management program are listed in 49 CFR 192, Subpart O and CSA Z662 [14, 15]. CGA P-8.10 contains general information about integrity management for industrial gas pipeline systems [10].

This section provides a summary of how hydrogen, carbon monoxide, and syngas can impact a pipeline integrity management program. The integrity management program components affected by hydrogen, carbon monoxide, and syngas are risk assessment, integrity assessment, and maintenance and monitoring.

9.1 Risk assessment

Risk assessments provide for both the potential impact of incidents and the likelihood that such events can occur. The probability of failure (PoF) and consequence(s) of failure (CoF) are both impacted by the composition of the gas being transported. The flammability of hydrogen, carbon monoxide, and syngas influences the CoF, including specific cases such as jet fire, flash fire, and vapor cloud explosions. In the case of carbon monoxide and syngas, the toxicity of carbon monoxide can have a greater influence on the CoF than the flammability. The corrosion mechanisms associated with hydrogen, carbon monoxide, and syngas influence the PoF. Description of typical damage mechanisms particular to hydrogen, carbon monoxide, and syngas are given in Appendix B.

Corrosion mechanisms, flammability, and toxicity of hydrogen, carbon monoxide, and syngas shall be considered when conducting a risk assessment in addition to typical pipeline hazard considerations. CGA P-8.10 describes the methodology for conducting risk assessments [10].

Risk assessment results are used to identify areas for integrity assessments and mitigative actions. All threats to pipeline integrity shall be identified and evaluated per ASME B31.8S, *Managing System Integrity of Gas Pipelines* [27].

Per ASME B31.8S, threats to pipelines are classified in the following areas [26]:

- Time-dependent threats—external corrosion, internal corrosion, stress corrosion cracking (SCC);
- Resident threats—manufacturing defects, construction defects, equipment failures; and
- Random or time-independent threats—third-party damage, incorrect operations, weather, outside forces.

When a risk assessment is conducted, the risk scores generated are used to establish the basis for prioritizing all future pipeline integrity assessments and preventative and mitigation measures, and for defining the integrity assessment intervals.

9.2 Integrity assessment

Integrity assessment is a process that includes inspection of the pipeline, evaluating the indications resulting from the inspections, direct examinations, evaluating the results of the examinations, and determining the resulting integrity of the pipeline through analysis. Integrity assessment methods are adapted to each threat category. The effect hydrogen, carbon monoxide, and syngas have on the probability and consequences of failure influence the schedule of inspections, but otherwise the approach to integrity assessment is the same for these pipelines.

See CGA P-8.10 for more information [10].

9.3 Maintenance and monitoring

A monitoring and maintenance plan shall be developed based on risk assessment results or integrity assessment results and applicable regulations. The effect hydrogen, carbon monoxide, and syngas have on the probability and consequences of failure influence the schedule of maintenance and monitoring, but otherwise the approach to maintenance and monitoring is the same for these pipelines.

See CGA P-8.10 for more details and information [10].

10 Corrosion and other damage to the pipeline system

As with any pipeline, damage to a hydrogen, carbon monoxide, or syngas pipeline can occur due to multiple causes, including aging/normal operation, corrosion, mishap, or third-party interference. The main difference between a hydrogen, carbon monoxide, or syngas pipeline and other pipelines is the corrosion mechanisms that apply and, for hydrogen pipelines, the increased potential for leaks due to the size of the molecule.

10.1 Corrosion and other damage mechanisms

Several brittle fracture mechanisms or degradation effects are attributed to hydrogen. These are described in Appendix B; however, not all are pertinent to dry hydrogen gas, dry carbon monoxide, or their mixtures. Specific attention shall be given to carbon monoxide and carbon monoxide mixtures, as the simultaneous presence of carbon monoxide, traces of carbon dioxide, and traces of water at temperatures below the dew point provides a susceptible environment for SCC in carbon and low alloy steels.

Brittle fracture and damage mechanisms that are pertinent to the transmission of hydrogen, carbon monoxide, and syngas by pipelines are as follows:

- For internal corrosion:
  - Hydrogen embrittlement at ambient temperature

  - SCC of carbon and low alloy steels in carbon monoxide environments; and
- For external corrosion (all pipelines):
  - SCC of line pipe materials in underground environments.

Hydrogen embrittlement covers several different phenomena, described in detail in Appendix B, that can lead to cracking during operation due to embrittlement of materials. Variables such as purity, temperature, and pressure can affect the severity of the embrittlement mechanisms encountered. In general, the risk of embrittlement in hydrogen atmospheres increases with increasing pressure.

SCC of pipeline materials in underground environments is a phenomenon that can be linked to several factors such as defective coatings, improper cathodic protection, and poor soil conditions. SCC of carbon and low alloy steels in carbon monoxide environments is usually attributed to the presence of contaminants in the carbon monoxide. Both SCC mechanisms are covered in more detail in Appendix B.

These damage mechanisms can lead to catastrophic failures. However, the normal design approaches to minimize the risks associated with these mechanisms are careful materials selection and reductions in global stress levels. Operational procedures that minimize water and carbon dioxide presence are beneficial for carbon monoxide and syngas services.

10.2 Damage to the pipeline system – leaks and defects

10.2.1 Leaks

It is essential that all leaks be quickly identified so that proper remediation can take place. If leakage of product from a pipeline is suspected and cannot be located through visual, audible, or analytical evidence, it might be necessary to isolate the pipeline in sections and pressure test it to identify the source of the leak or prove that the pipeline is sound.

Another method of locating small leaks is to use sophisticated detection equipment that can identify minute amounts of inert substances known as tracer compounds that are injected into the pipeline.

10.2.2 Defects

Defects can be coating defects, dents, gouges, welding arc strikes, pits, cracks, and corrosion damages to the pipe. Defects shall be evaluated with respect to their severity and the contained fluid to define the proper type of repair, replacement, or reinforcement of the damaged piping and remediated as required.

Coating defects may increase corrosion potential, however the defects might not need to be repaired if the cathodic protection system is functioning and maintaining protection.

It is important to capture the geographic coordinates of the damages to the pipe and track the repairs.

Various methods can be used to detect and assess defects caused by the many different types of threats to a pipeline (see CGA P-8.10, *Industrial Gas Pipeline Integrity Management* [10])

10.3 Significant pipeline damage

Consideration should be given to revalidation (a detailed inspection that includes a pressure test) to establish the pipeline's suitability for continued service after an incident occurs that can call it into question. The contained fluid shall be part of the risk evaluation for continued operation. Substantial damage, possibly with leakage, fire, or other significant pipeline incident could warrant revalidation. Similarly, a significant modification to the pipeline system can suggest comparable action.

10.4 Corrosion protection

10.4.1 Corrosion protection of underground pipelines

Corrosion caused by galvanic action between the outside of the pipe and the soil is probably the most frequent cause of leaks except for mechanical damage. If corrosion is not prevented or sufficiently inhibited, eventually holes will form in the pipe during its working life. Corrosion protection is achieved by a suitable coating system and supported by cathodic protection in the event of the loss of the coating system integrity. To achieve good cathodic protection, it is necessary to understand the soil conditions and the anti-corrosion methods used by nearby pipelines. The advice of an expert in these matters is recommended. Cathodic protection can be done according to recognized standards, such as NACE Standard SP0177, *Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems*, NACE Standard SP0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, or EN 1295, *General principles of cathodic protection of buried or immersed onshore metallic structures* [28, 29, 30].

10.4.2 Corrosion protection of aboveground pipelines

Because aboveground pipelines can be visually inspected, corrosion can be more easily controlled. However, this is only the case if the inspections are frequent, methodical, and all the discovered problems remediated.

Uninsulated aboveground pipelines should be protected against environmental corrosion by an appropriate coating system, usually paint. The system selection varies with the environment, but a system suitable for a chemical plant environment should be used as a minimum.

Insulated aboveground pipelines are also subject to environmentally caused corrosion, which occurs underneath the insulation and is therefore not visible. This type of corrosion is quite common and is recognized as a significant problem in the industry. For more information, see NACE Standard SP0198*, Control of Corrosion Under Thermal Insulation and Fireproofing Materials—A Systems Approach* [31].

11 Pipeline repair and modification

Damage identified during routine pipeline maintenance or damage from incidents (e.g., damage from digging) can require repair. Some damage requires immediate repair, while other damage is less critical such that repair can be scheduled to allow for proper planning and preparation, and still other damage can either be monitored or preventive or mitigative measures taken to reduce or eliminate the threat. The severity of the damage shall be assessed and the pipeline judged to be suitable to return to service either permanently or temporarily, or to require immediate repair. If monitoring rather than immediate repair is possible, the inspection intervals will be determined based on the characterization of the defect indications, the level of mitigation achieved, and the preventive methods employed. Inspection intervals are mandated in 49 CFR in the United States,
CSA Z662 in Canada, and EN 16348, Gas infrastructure. Safety Management System (SMS) for gas transmission infrastructure and Pipeline Integrity Management System (PIMS) for gas transmission pipelines, Functional requirements in Europe [14, 15, 32].

Damage that can require an immediate response include:

- SCC;
- Through-wall damage;
- Corroded areas that have a predicted failure pressure level less than 1.1 times the maximum allowable operating pressure (MAOP);
- Third-party damage (for example, dents with gouges and/or corrosion).

Damage that can have a scheduled response include:

- mechanical damage with or without concurrent visible indentation of the pipe;
- dents with cracks;
- dents that affect ductile girth; or
- seam welds if the depth is more than 2% of the nominal pipe diameter and dents of any depth that affect nonductile welds.

Refer to CGA P-8.10 for more information on how to modify the pipeline integrity management program in response to the discovery of damage [10].

Some repair activities can require the pipeline to be shut down, while others may be completed on an active pipeline.

11.1 Safety considerations for maintenance and repair

When performing work on a hydrogen, carbon monoxide, or syngas system, the following safety precautions are required:

- Safe work permit when performing maintenance and/or repairs. It should specify the presence of a minimum of two persons when there is work that can involve a release of gas. The personnel involved in the work, including contractors, shall be qualified and shall be informed of the abnormal operating conditions, the hazards of hydrogen, carbon monoxide, or syngas, and the tasks to be performed;
- Gas detection and monitoring before and while performing work on a carbon monoxide or syngas system;
- Sufficient emergency escape self-contained breathing apparatuses (SCBA) in the work area based on the number of workers and the type of work being conducted and gases present in the system;
- Use of nonsparking tools, if necessary;
- Positive isolation and zero energy verification before performing maintenance and/or repairs;
- Proper purging and inerting before any work where gas can potentially be released, including welding or cutting; and
- Fire watch when performing welding or cutting.

In addition to the previous requirements, wearing portable personal gas monitors is recommended when working on hydrogen pipelines and is required when working on a carbon monoxide or syngas pipeline. Personal monitors can be configured to detect a single gas (e.g., carbon monoxide), or can be multi-sensor monitors (e.g., oxygen, carbon monoxide, flammability). Personal monitors should be fastened to clothing near the breathing zone.

Venting to a flare system can be required when purging a carbon monoxide or syngas system, depending on federal, state, provincial/territorial, and local regulations and on the volume of gas to be vented. The location of the work and the potential impact on the public during purging and maintenance shall be considered.

Temporary grounding is recommended during maintenance and/or repair.

11.2 Preparation for repair

Before conducting maintenance work on the pipeline, it shall be prepared for maintenance.

A positive shutoff is required if the repair requires the pipeline to be shut down. This shutoff can be carried out by:

- Complete disconnection of the section concerned from the pipeline system;
- Installation of blind flanges; or
- Closure and mechanical locking of two valves arranged in tandem with an open venting valve between them (if the valve has an electric drive, the power also should be disconnected) or a double trunnion-mounted ball valve equipped with a body vent.

A check valve shall not be used as a shutoff mechanism for maintenance work.

Inerting of the section of pipe to be repaired, which should include local analysis, shall be done before the start of any work.

In the case of carbon monoxide and syngas pipeline repair, special care shall be taken as iron (nickel) carbonyl can form due to the action of carbon monoxide on alloys that contain iron (nickel). Nickel carbonyl can be present in stainless steel syngas pipelines, as hydrogen influences the rate of reaction of carbon monoxide and nickel to form nickel carbonyl.

Lockout and tagout procedures shall be used to indicate that the equipment has been placed in the shutoff position and to reduce the risk of uncontrolled operation of the valves. Operations shall inform the maintenance team that the pipeline is ready for their work.

All repairs and alterations to the pipeline shall be performed in accordance with the relevant piping code and any jurisdictional requirements. If provisions in relevant piping codes present a direct or implied conflict with jurisdictional requirements, the jurisdictional requirements shall govern. This includes the requirement for any qualified individuals. Before any repair or alterations are performed, all proposed methods of design, execution, materials, welding procedure, nondestructive examination (NDE) inspection, and testing shall be approved.

See ASME PCC-2, *Repair of Pressure Equipment & Piping Overview* for guidance on performing repairs on a pipeline [33].

11.3 Vent site selection

The location of potential vent sites should be chosen with care and, to the extent practical, avoid the immediate proximity of vulnerable areas and equipment such as electrical equipment, flammable product storage tanks, public roads, public buildings, car parks, and transfer stations. Site selection and safety distances should follow established practices and applicable jurisdictional regulations.

Safe distances for hydrogen in relation to other areas and equipment can be found in NFPA 2, *Hydrogen Technologies Code*, and NPFA 55, *Compressed Gases and Cryogenic Fluids Code* [34, 35]. The OSHA requirements for hydrogen are found in 29 CFR Part 1910.103 [8]. For carbon monoxide or syngas, a release creates two types of risks, both of which shall be considered: one is the thermal and pressure effect if the release is ignited; the other is toxicity due to the presence of carbon monoxide.

During station maintenance, the mass of released gas is limited to the mass contained in the station except in cases of internal leak of a pipeline isolation valve or human error. During pipeline maintenance, the mass of released gas can include the mass contained in the pipeline. In both cases, a dispersion study should be conducted before conducting any significant venting. The parameters to be considered for the dispersion study and the definition of the safety zones are the height of the vent, the flow, the velocity, and the duration of the gas released.

Unless welded and bellow valves are used, unexpected leaks to the atmosphere can occur from equipment such as flanges and valve packings. Detection means and emergency response time are factors to consider in the design of the stations.

11.3.1 Venting

Small quantities of hydrogen, carbon monoxide, or syngas can be vented to the atmosphere in a safe location by maintaining a high upward velocity to facilitate dispersion and adding nitrogen if necessary.

Large quantities of hydrogen, carbon monoxide, or syngas shall be directed to a vent (hydrogen only) or flare system (permanent or mobile).

In case of emergency, when large quantities of hydrogen, carbon monoxide, or syngas require venting to atmosphere and flaring is not possible, the vent shall be routed to a stack that is directed away from personnel, buildings, and enclosures, in a location where neither personnel nor vulnerable items of equipment will be exposed to hydrogen, carbon monoxide, or syngas. It should be assumed that the vent flow can ignite, and an analysis should be performed to confirm that allowable radiation criteria are not exceeded. Venting should not take place directly beneath any overhead power or communication lines.

See CGA G-5.5, *Standard for Hydrogen Vent Systems*, for more information on vent system considerations and design requirements [36].

11.3.2 Purging and inerting

Purging of hydrogen, carbon monoxide, or syngas, except for relatively small quantities, can require the use of a vent (hydrogen only) or flare system. The flare system shall be purged of air before introducing the hydrogen, carbon monoxide, or syngas to avoid ignition inside the piping.

Nitrogen or another inert gas shall be used to purge hydrogen, carbon monoxide, or syngas from the pipeline before loosening or disconnecting flanges, instruments, etc. Dead-ended legs of the pipeline system that cannot be swept by nitrogen shall be pressure purged. The pressure purge starts by introducing the nitrogen (or other inert gas) at a low pressure, ramping up to higher pressure, and then safely venting the nitrogen to bring the pipeline or pipeline equipment to lower pressure and lower concentration of pipeline gas. This sequence is repeated until the nitrogen concentration is high enough (or the original pipeline gas concentration is low enough). The number of pressure purging cycles shall be evaluated for each specific job.

A written purging plan should be prepared that ensures all hydrogen, carbon monoxide, or syngas is removed from the pipeline system to a defined acceptable concentration depending on the gas service and the work being performed.

Unauthorized access to the outlet shall be prevented so no one is endangered by oxygen-deficient atmospheres.

For more details on the requirements of purging out of service, consult NFPA 56, *Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems* [37].

11.4 Welding and cutting

All welding on pipe sections and connections shall meet recognized welding standards. Low hydrogen electrode and preheating methods should be considered. When welding piping or components that have been in hydrogen service, hydrogen bakeout should be considered to improve weldability.

Pipe sections shall be welded together.

Where possible, connections to components shall be welded to minimize potential leak sources. Threaded connections that are seal welded are considered welded connections for this purpose, although threads even when back welded are crevices in the system that can harbor corrosion and should be avoided. Where welded connections are not possible, flanged connections shall be used wherever practical. Seamless or longitudinally welded pipe and wrought or machined fittings shall be used.

Threaded connections shall be used only where welded (including seal welded threaded connections) and flanged connections are not practical. For carbon monoxide and syngas pipelines, the sealant shall be hydrogen and carbon monoxide compatible; for hydrogen pipelines, the sealant shall be hydrogen compatible. In all cases, the sealant shall be high-temperature resistant to reduce the risk of leaks during a fire.

11.4.1 In-service welding and cutting

Any welding on active or in-service pipelines can cause localized heating and/or adversely affect the integrity of the piping system and, therefore, shall be avoided. The only exceptions are drilling small openings in depressurized pipelines during connection work, welding on cathodic protection devices (external but connected to the pipeline), and hot tap welding.

Active or in-service pipeline welding and cutting requires special equipment and procedures and shall be carried out only under the supervision of trained personnel. Before conducting any welding on active or in-service pipelines, it shall be verified that the pipe metallurgy and integrity will not be adversely affected. Although it is preferred that these processes be done when the line is out of service, it is recognized that occasions might arise when this is not practical, but these should be minimized.

11.4.2 Out-of-service welding and cutting

All maintenance welding of pipelines shall be to the standards and requirements called for in:

- API Specification 5L, *Line Pipe* [38];
- EN 10208-2, *Steel Pipes for Pipelines for Combustible Fluids. Technical Delivery Conditions – Pipes of Requirement class B* [39];
- 49 CFR Part 192 [14];
- CSA Z662, *Oil and Gas Pipeline Systems* [40];
- ASME B31.8S [27];
- API 1104, *Welding Pipelines and Related Facilities* [41];
- ASME B31.12, *Hydrogen Piping and Pipelines* [42];
- ASME PCC-2 [33]; and
- ASME B31.3, *Process Piping* [43].

Cold cutting of pipelines for tie-in and repairs is preferred to reduce the possibility of ignition, keeping in mind that this does not reduce any of the requirements for safe maintenance activities.

11.4.3 Hot tapping pipelines

Hot tapping is the technique of attaching a welded branch fitting to piping that is in service and then creating an opening in that piping by drilling or cutting a portion of the piping within the attached fitting. The process is completed without leakage and interruption of flow. A typical hot-tap application includes the use of a fitting designed to contain system pressure welded to the pipeline, a valve used to control the new branch connection, and the drilling/hole cutting machine to make the hot-tap.

Hot tapping is usually performed when it is not feasible, or is impractical, to take the equipment or piping out of service, or to purge or clean it by conventional methods. A hot tap shall not be a routine procedure but shall be used only when there is no other practical alternative.

Because of the risks involved with welding on a pressurized pipeline, it is important to fully evaluate the process before executing the work. Welding parameters and flow conditions shall be set to ensure that welds on the pipeline do not result in burn through (heat input too high) or hard welds (heat input too low). Some operators also limit the inside pipewall temperature to minimize hydrogen absorption by the steel. Before considering hot tapping any hydrogen, carbon monoxide, or syngas pipeline, a thermal analysis shall be performed by a qualified engineer. That analysis will provide the product flow and weld parameters during the hot tap.

More information on hot tapping is available in API RP 2201, *Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries* and ASME PCC-2, Article 216 *Welded Hot Taps in Pressure Equipment or Pipelines for design, fabrication, testing, installation, and recommendations* [44, 33].

11.5 Inspection following repair, modification, or replacement

Following repair, modification, or replacement modification, piping shall be inspected and tested in accordance with the relevant piping code and procedures as defined in the project specification. Such inspections should include as a minimum those to verify the following:

- Correct materials (as a minimum by stamped markings and/or accompanying paperwork such as material testing report [MTR]). Positive materials identification spot checks (for example, 10%) could also be done;
- Pipe concentricity;
- Specified wall thickness;
- Internal cleanliness;
- Protective coating integrity;
- Electrical isolation;
- Absence of mechanical damage, e.g., gouges, dents, etc.;
- Joint preparation;
- Welding fit-up;
- Welding;
- Absence of arc burns; and
- Review of radiographic or other examination.

For pipelines in the public domain, CGA P-8.10 addresses integrity management programs for industrial gas pipelines, including maintenance, inspection, and operation [10].

11.5.1 Documentation

The following documents relating to the repair of the pipeline shall be retrieved and collected in a dossier that is retained for reference by the operator:

- The project specification;
- Pressure test report;
- Weld procedures, procedure qualifications, and qualification records for each welder;
- Weld joint NDE reports (including rejects/repairs, weld map, weld operator identification, welding technique used);
- Summary of all NDE procedures demonstrating that all code, regulatory, and project specific requirements have been met;

- Report of internal pipe cleaning and inspections;
- Reports for all inspection activities;
- Material test reports (MTR);
- Other reports and certificates required by federal, state, provincial/territorial, local authorities, and relevant piping codes;
- Protective coating integrity test report (report on pinholes or defects in the external coating); and
- Cathodic protection and electrical isolation report.

At the completion of the work, the repairer should supply a written statement that all NDE requirements have been met and that the results have been verified by a qualified individual (e.g., level 2 or level 3 NDE qualification per *ASME Boiler & Pressure Vessel Code*, Section V) [45].

11.6 Leak and pressure testing

The purpose of testing is to check that, at a pressure with a defined safety margin in relation to the MAOP, the equipment does not exhibit leaks or deformation. This could be required periodically as part of the integrity management program, following a major repair, or as part of a project to increase the MAOP of a pipeline.

11.6.1 Leak testing

After major maintenance or during recommissioning, a pipeline system is leak tested to verify that it can operate at its operating pressure while not suffering an unacceptable loss of product through leaks. This is done by pressurizing the system with a suitable inert medium (e.g., nitrogen or helium). Leak testing is performed at or below the MAOP of the system. Leak testing is frequently pneumatic, but hydrostatic leak testing is possible. If pneumatic testing is performed, appropriate safe distances shall be established. For more information, see ASME PCC-2 [33].

Typically leak testing is conducted once all the piping has been installed and connected.

11.6.2 Pressure test

Following major repairs, pressure testing could be required to verify its mechanical integrity in accordance with the relevant codes and standards or local jurisdiction requirements. Testing may happen for individual sections of the final assembly, or the entire assembly. This can take place either at a fabricator or in the field. Also, the station is usually tested separately from the pipeline.

Hydrostatic testing is the preferred method of testing rather than pneumatic pressure testing if practical and possible. While hydrostatic testing is generally safer than pneumatic testing due to lower stored energy, it is not without risk, and appropriate safeguards are required. Where hydrostatic testing is not practical or possible, pneumatic pressure testing may be considered. If a complete system dry out is essential, as in cases where water residue would cause operating problems or corrosion, then pneumatic testing is preferred.

After completing a hydrostatic test, the water preferably is removed immediately either by draining, pigging, or a combination of the two. Final drying may be accomplished via nitrogen pressure pumping or, if a very low dew point (e.g., less than –70 °F [–57 °C]) is required, via vacuum drying.

Any residual water in a carbon monoxide or syngas pipeline following a hydrostatic test could lead to failure mechanisms within the pipeline; therefore, it is imperative to achieve a maximum dew point of –58 °F (–50 °C).

For reasons of practicality in the case of pipe tie-ins or final closing welds, it might be acceptable to waive the need for a pressure test if a prescribed alternative method of nondestructive testing is carried out and local regulations do not prohibit it. Before performing any pressure test, a risk analysis shall be performed to review the testing plan and safety precautions shall be taken accordingly.

For additional information on managing, planning, preparation, pressure testing the piping, depressurizing, safe exposure distances, and restoring the system to service, see ASME PCC-2 [33].

11.7 Restoring pipelines and stations to service following outage

After the successful mechanical completion of the repair or maintenance work including all testing, cleaning, and drying, the pipeline is ready for recommissioning. The maintenance team should inform operations of the completion of the work and that the system is ready for recommissioning.

The steps in recommissioning the pipeline are:

a) remove any blind flanges;

b) flow and/or pressure purge the pipeline with nitrogen until all air and moisture are removed, and verify by analysis;

c) leak check at low pressure using an inert gas;

d) depressurization while maintaining slight overpressure to avoid air ingress;

e) introduce hydrogen, carbon monoxide, or syngas and vent (or flare, if appropriate);

f) pressure purge any dead-ended legs with hydrogen, carbon monoxide, or syngas;

g) test for required purity of hydrogen, carbon monoxide, or syngas;

h) close all vent and purge valves;

i) pressurize the system to operating pressure; and

j) leak check all valves, flanges, and fittings.

Once the pipeline has been purged of air using nitrogen or other inert gas, the pipeline is purged with hydrogen, carbon monoxide, or syngas as applicable to remove the nitrogen from the pipeline. The purging process is carried out through the last valve under pressure using throttling and bypass valves if present (depending on the nominal diameter of the pipeline). The hydrogen, carbon monoxide, or syngas should be introduced in a specific direction to ensure hydrogen, carbon monoxide, or syngas purity. All flow purging should be done at low pressure as a safety precaution.

The purity of the hydrogen, carbon monoxide, or syngas should be measured at all outlets using analysis equipment. If the purity, as required by the customer specifications, is adequate at a valve outlet, the relevant valve can be closed.

When the pipeline has been purged and all the purging points have been closed, the pipeline can be pressurized using a bypass, throttling, or control valve to slowly pressurize the pipe up to the operating pressure.

All mechanical connections such as flanges, valve bonnets, threaded couplings, etc., should be checked for leaks at regular intervals during recommissioning.

12 Converting existing pipelines to hydrogen, carbon monoxide, or syngas service

When converting an existing pipeline to hydrogen, carbon monoxide, or syngas service, the pipeline operator shall first confirm the suitability of materials of construction for the new gas service. The strength and hardness of all piping components in hydrogen-containing service shall be considered to address the likelihood of hydrogen embrittlement. For more information on hydrogen embrittlement and mitigations, see Appendix B and API 571 [25].

The pipeline operator shall review original specifications and inspection and maintenance records and develop an inspection plan based on that information. Information regarding the operational history of the pipeline shall be obtained, to the extent available, from the pipeline operator's files and by discussions with the pipeline operator's operating personnel. Based upon assessing this information, the pipeline operator may decide not to convert the pipeline to hydrogen, carbon dioxide, or syngas service.

12.1 Pipeline records

Pipeline records should include all construction documents (including hydrostatic test records, welding procedures, and pipeline specifications) and the operating and maintenance manuals.

12.1.1 Fluid service

It is important to know which fluids have been transported through the pipeline during its operational life. Some fluids are potentially corrosive, while others leave deposits in the pipeline. The pipeline operator shall be requested to provide a list and analysis of the fluids that have been used in the pipeline since construction and the MAOP of the pipeline.

12.1.2 Leaks and repairs

The pipeline operator shall provide a record of incidents and repairs, including the material specifications for the pipeline used in the repairs, from the beginning of operation in the pipeline operator's possession.

12.1.3 Cathodic protection

The quality of the coating of a pipeline and the protection of this coating by cathodic protection are the principal factors that determine the useful life of the pipeline. The condition of the coating and cathodic protection system shall be determined in order to establish the usability of a pipeline being considered and the risk associated with the proposed operation in hydrogen, carbon monoxide, or syngas service.

The pipeline operator should be requested to provide cathodic test records since construction, or at least for the last 10 years, and a map showing the locations of test points. The pipeline operator should check the integrity of the cathodic protection system, including impressed current electrical equipment and anode beds. The pipeline operator should also check for stray currents from any nearby high voltage transmission lines that can cause damage.

12.1.4 Pipeline test data

The pipeline operator shall provide a record of the hydrostatic test(s) carried out at the time of construction and records of any subsequent hydrostatic test(s) and/or instrumented internal inspection device evaluation(s) in the pipeline operator's possession.

12.1.5 Pipeline material records

The pipeline operator should determine the material of construction of all pipeline components, verify material compatibility, and locate and review the material certifications.

The pipeline operator should be requested to provide all mill certificates for pipeline material (including repair material) in the pipeline operator's possession. These should show the chemical analysis, the yield strength, the ultimate tensile strength, and the Charpy impact strength of the pipeline material. The welding procedure and the inspection file should be provided. If the required material data are not available, a material audit and inspection shall be carried out.

12.1.6 Drawings

The pipeline operator should be requested to provide copies of drawings in the pipeline operator's possession covering the pipeline to be converted. They are necessary to locate the pipeline for operational purposes.

12.1.7 Risk assessment

A hazard evaluation and comprehensive risk assessment should be performed to determine the pipeline suitability for conversion, in accordance with 5.2. The initial assessment, based on data gathered from 12.1.1 to 12.1.6, provides a baseline risk profile. This will be further refined through ongoing inspections outlined in 12.2 to 12.7, ensuring up-to-date risk characterization. The results will guide inspection priorities, necessary modifications, and mitigation measures for safe and reliable operation of the pipeline before conversion.

12.2 Visual inspection

12.2.1 Piping

Aboveground piping shall be inspected to observe the condition of paint or coating and the condition of valves or other equipment that are part of the pipeline to be converted. The spacing between isolation valves shall comply with applicable federal, state, provincial/territorial, and local regulations.

Certain sections of pipe might need to be excavated for visual inspection to check coatings and any ultrasonic testing (UT) thickness test based on pigging results or inspection and maintenance records.

12.2.2 Crossings

All points at which the pipeline crosses roads, railways, rivers, and creeks should be examined. Erosion of the soil can have exposed the pipeline at some locations, requiring repair or replacement of the pipeline. There should be markers at all crossings, as these are locations most likely to be subject to excavation or drilling by others.

12.2.3 Route

Perform a route survey to determine class location and conduct a risk assessment to determine if there will be unacceptable risks to any nearby facilities (i.e., schools, hospitals, etc.), and if additional safety measures need to be implemented. Consult with applicable Right of Way (ROW) pipeline operators to understand what other materials are in the ROW and advise the ROW pipeline operator of the intention to repurpose the pipeline.

Document the location and number of occupied buildings in the area of the pipeline and also any other structures that exist on the ROW of the pipeline. Documentation should be made of the location of all markers and cathodic protection connections.

The list of landowners should be updated with current addresses and telephone numbers. Easement agreements should be checked to ensure that they correspond to current ownership. An environmental assessment should be conducted to ensure there are no contaminated or hazardous waste sites on the pipeline route.

12.3 Physical inspection

12.3.1 Location

The pipeline location should be verified (depth and horizontal) and compared to the drawings every mile.

12.3.2 Depth of cover

Pipelines are normally buried at sufficient depth to protect them from agricultural operations. Erosion of soil eventually can reduce this coverage to a point where the pipeline is in danger of being damaged by plowing and other surface activities. If the depth of cover is less than that required by federal, state, provincial/territorial, and local regulations, remedial work can be required.

Pipeline markers and test points should be checked against the drawings, and if missing, replacement shall be included in the project scope.

Federal, state, provincial/territorial, and local regulations can restrict the allowable pressure in the pipeline if there has been an increase in population density in the immediate vicinity.

A survey shall be made to count the number of buildings intended for human occupancy located near the pipeline as required by federal, state, provincial/territorial, and local regulations.

12.4 Material audit in case of unknown material properties

12.4.1 Positive material investigation

Positive material investigation (PMI) should be carried out. This can be done by removal of coupons for analysis, or by in-situ testing.

PMI results should provide evidence of material conformity to specifications.

Charpy impact testing of coupons should be prepared from the base material and welds. A minimum of one base and weld material per mile of pipeline should be examined. Impact test results should also be examined. See 12.4.3 for guidance.

12.4.2 Material analysis

Weld and base metal coupons shall be subject to laboratory analysis to determine metallurgical conditions (martensite-perlite, hardness, and ultimate tensile strength [UTS]). A minimum of one sample per mile of pipeline should be examined.

12.4.3 Compliance

Nonconformance with material specification requirements requires additional evaluation for the use of the pipeline for the intended service.

On a case-by-case basis, it might be deemed necessary to conduct a rigorous metallurgical investigation. Pipeline age, pipeline location, prior history, and the projected operating conditions such as high pressures are factors in the decision and final test plan.

12.5 Internal pipeline inspection and testing

Internal pipeline inspection can be required if:

- Cathodic protection records are missing or if they indicate that protection has been inadequate;
- The previous service history of the pipeline is unknown or if it has carried fluids such as crude oil or wet natural gas, which are known to increase the likelihood of internal corrosion; or
- Original material data reports for the pipeline are missing, whereby internal inspection is required to supplement data obtained from samples (see 12.4.1 and 12.4.2).

Consider running a smart pig for integrity verification. The user shall confirm that the line is able to be pigged before utilizing this technique. The smart pig or other internal pipeline inspection device should be capable of locating internal and external corrosion, buckles and dents, and actual wall thickness. If corrosion is found, either the areas of corrosion may be cut out and replaced with new pipeline, or the pipeline might need to be re-rated according to the applicable design standard.

Pressure test the pipeline (typically with water), at a test pressure that is determined by the required operating conditions (see 11.7).

12.6 Valves, flanges, and instrumentation

Refurbishment of all valves and flanges should be considered, and flange joints should be replaced by welded joints where possible. The suitability and sizing of all valves and instrumentation should be reviewed for the new gas service.

In the case of any recommissioned pipeline, all valves and flange joints shall be tested for fugitive emissions.

Adjust and calibrate flowmeters for the new gas. Older flowmeters might need to be replaced.

12.7 Cleaning

Unless the pipeline has previously been used for a clean, dry gas and continuously inerted when out of service, a cleaning procedure should be carried out. Pigs are commonly used for internal cleaning of pipelines. Other methods include mechanical scraping or high-velocity gas purge.

12.8 Records

Records shall be kept including all investigations, tests, repairs, replacements, and alterations made under the requirements of this publication. The records shall be retained in accordance with applicable regulations and company policies.

13 Transmission of hydrogen blends

Blending hydrogen into natural gas pipeline networks is a means to deliver lower carbon intensity fuels to markets. Blending will also allow the transition of existing natural gas systems to deliver pure hydrogen to the market.

The appropriate blend concentration can vary significantly between pipeline network systems and natural gas compositions and shall therefore be assessed on a case-by-case basis. Any introduction of a hydrogen blend concentration requires extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (e.g., integrity management systems).

Considerations include but are not limited to level of hydrogen, materials of construction of pipeline and soft goods, other gases being blended to control heating value, odorization, etc. The damage mechanisms referenced in this publication specific to hydrogen shall be considered in blending operations. See Section 12 for additional information regarding assessments required for change of pipeline service.

For more information on this topic, please see:

- National Renewable Energy Laboratory (NREL) Report, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues* [46];
- MDPI Report, *Hydrogen Blending in Gas Pipeline Networks – A Review* [47];
- European Commission JRC Technical Report, *Blending Hydrogen from Electrolysis into the European Gas Grid* [48];
- NREL Report, *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology* [49]; and

- Department for Energy Security & Net Zero Report, *Hydrogen Blending into GB Gas Distribution Networks: Government Response to Consultation* [50].

14 Additional codes, standards, and guidelines

Other codes, standards and guidelines exist which may be applicable to the design, operation and maintenance of hydrogen, carbon monoxide and syngas pipelines. See Appendix C.

15 References

Unless otherwise stated, the latest edition shall apply.

[1] CGA P-11, *Guideline for Metric Practice in the Compressed Gas Industry*, Compressed Gas Association, Inc. www.cganet.com

[2] ANSI/CGA G-5, *Hydrogen (an American National Standard)*, Compressed Gas Association, Inc. www.cganet.com

[3] *Handbook of Compressed Gases*, Compressed Gas Association, Inc. www.cganet.com

[4] *Threshold Limit Values (TLVs®) and Biological Exposure Indices (BEIs®)*, The American Conference of Governmental Industrial Hygienists. www.acgih.org

[5] ORNL/TM-5499, *Iron and Nickel Carbonyl Formation in Steel Pipes and Its Prevention – Literature Survey*, J. Brynestad, Oak Ridge National Laboratory, www.osti.gov

[6] *Code of Federal Regulations*, Title 29 (Labor), U.S. Government Printing Office. www.gpo.gov

[7] NFPA 70®, *National Electrical Code®*, National Fire Protection Association. www.nfpa.org

[8] CSA C22.1, *Canadian Electrical Code,* CSA Group. www.csagroup.org

[9] ATEX Directive 2014/34/EU, *Equipment for potentially explosive atmospheres*, European Commission. https://eur-lex.europa.eu/eli/dir/2014/34/oj

[10] CGA P-8.10, *Industrial Gas Pipeline Integrity Management*, Compressed Gas Association, Inc. www.cganet.com

[11] Directive 2012/18/EU, of the European Parliament and of the Council of 4 July 2012 on the *control of major-accident hazards involving dangerous substances, amending and subsequently repealing Council Directive 96/82/EC Text with EEA relevance* (SEVESO). https://eur-lex.europa.eu/eli/dir/2012/18/oj

[12] CSA Z767, *Process safety management,* CSA Group. www.csagroup.org

[13] CGA P-86, *Guideline for Process Safety Management*, Compressed Gas Association, Inc. www.cganet.com

[14] *Code of Federal Regulations*, Title 49 (Transportation), U.S. Government Printing Office. www.gpo.gov

[15] CSA Z662, *Oil and gas pipeline systems*, CSA Group. www.csagroup.org

[16] API RP 1168, *Pipeline Control Room Management*, American Petroleum Institute. www.api.org

[17] EIGA Doc 40, *Work Permit Systems*, European Industrial Gases Association. www.eiga.eu

[18] EIGA SI-HF 10, *Organisation - "Managing Organisational Change"* European Industrial Gases Association. www.eiga.eu

[19] EIGA Doc 51, *Management of Change*, European Industrial Gases Association. www.eiga.eu

[20] ISO 45001, *Occupational health and safety management systems — Requirements with guidance for use*, International Organization for Standardization. www.iso.org

[21] *Guidelines for the Management of Change for Process Safety*, Center for Chemical Process Safety. www.aiche.org/ccps

[22] API RP 581, *Risk Based Inspection (Methodology)*, American Petroleum Institute. www.api.org

[23] ASME A13.1 *Scheme for the Identification of Piping Systems*, The American Society of Mechanical Engineers. www.asme.org

[24] ASME B31.8, *Gas Transmission and Distribution Piping Systems*, The American Society of Mechanical Engineers. www.asme.org

[25] API 571, *Corrosion and Materials*, American Petroleum Institute. www.api.org

[26] ANSI/NACE Standard RP0502, *Pipeline External Corrosion Direct Assessment Methodology (an American National Standard)*, The Association for Materials Protection and Performance. www.ampp.org

[27] ASME B31.8S, *Managing System Integrity of Gas Pipelines*, The American Society of Mechanical Engineers. www.asme.org

[28] NACE Standard SP0177, *Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems*. The Association for Materials Protection and Performance. www.ampp.org

[29] NACE Standard SP0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, The Association for Materials Protection and Performance. www.ampp.org

[30] EN 1295, *General principles of cathodic protection of buried or immersed onshore metallic structures*, British Standards Institute. www.knowledge.bsigroup.com

[31] NACE Standard SP0198, *Control of Corrosion Under Thermal Insulation and Fireproofing Materials—A Systems Approach*, The Association for Materials Protection and Performance. www.ampp.org

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[33] ASME PCC-2, *Repair of Pressure Equipment & Piping Overview*, The American Society of Mechanical Engineers. www.asme.org

[34] NFPA 2, *Hydrogen Technologies Code,* National Fire Protection Association. www.nfpa.org

[35] NFPA 55, *Compressed Gases and Cryogenic Fluids Code*, National Fire Protection Association. www.nfpa.org

[36] CGA G-5.5, *Standard for Hydrogen Vent Systems*, Compressed Gas Association, Inc. www.cganet.com

[37] NFPA 56, *Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems*, National Fire Protection Association. www.nfpa.org

[38] API Specification 5L, *Line Pipe*, American Petroleum Institute. www.api.org

[39] EN 10208-2, *Steel pipes for pipelines for combustible fluids. Technical delivery conditions - Pipes of requirement class B*, British Standards Institute. www.knowledge.bsigroup.com

[40] CSA Z662, *Oil and gas pipeline systems*, CSA Group Testing & Certification, Inc. www.csagroup.org

[41] API Standard 1104, *Welding Pipelines and Related Facilities*, American Petroleum Institute. www.api.org

[42] ASME B31.12, *Hydrogen Piping and Pipelines*, The American Society of Mechanical Engineers. www.asme.org

[43] ASME B31.3, *Process Piping*, The American Society of Mechanical Engineers. www.asme.org

[44] API RP 2201, *Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries*, American Petroleum Institute. www.api.org

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[46] NREL Report on Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, The National Renewable Energy Laboratory. www.nrel.gov

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[51] ISO 11114-4, *Transportable gas cylinders — Compatibility of cylinder and valve materials with gas contents, Part 4: Test methods for selecting steels resistant to hydrogen embrittlement*, International Organization for Standardization. www.iso.org

[52] ASME PVP2018-84658, *Influence of Hydrogen and Oxygen Impurity Content in a Natural Gas / Hydrogen Blend on the Toughness of an API X70 Steel*, The American Society of Mechanical Engineers. www.asme.org

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[54] ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines*, The American Society of Mechanical Engineers. www.asme.org

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[56] ASME B31.4 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, The American Society of Mechanical Engineers. www.asme.org

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[65] ISO 15590-1, *Oil and gas industries including lower carbon energy — Factory bends, fittings and flanges for pipeline transportation systems, Part 1: Induction bends*, International Organization for Standardization. www.iso.org

[66] ISO 17636-1, *Non-destructive testing of welds — Radiographic testing, Part 1: X- and gamma-ray techniques with film*, International Organization for Standardization. www.iso.org

[67] API RP 500, *Classification of Locations for Electrical Installations at Petroleum Facilities Class*, American Petroleum Institute. www.api.org

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Appendix A—Example of preventive maintenance program for hydrogen pipelines (Informative)

Intervals shown are only examples and do not reflect required or universal practices.

Pipeline systems	Checking interval						
	1 mo	3 mo	6 mo	1 yr	3 yr	5 yr	When required
Underground pipelines							
Pipeline patrol	X						
Pipeline patrol in critical areas	Daily						
On-foot servicing inspection				X			
Pipeline risers and casing inspection			X				
Effect of mining (subsidence)					X		
Aboveground pipelines							
Pipeline patrol and servicing			X				
Pipe bridges-inspection and painting				X			
Supports and anchorages						X	
Inner pipeline inspection							X

Cathodic protection	Checking interval						
	1 mo	3 mo	6 mo	1 yr	3 yr	5 yr	When required
Drainage stations	X						
Impressed current stations	X						
Protection devices against AC	X						
Pipe/ground DC potential, on/off			X				
Pipe/ground AC potential and current			X				
Earths, anodes, connections fuses, spark gaps			X				
Insulating joints			X				
Overall cathodic protection effectiveness				X			
Coating defect detection in sensitive areas						X	
Comprehensive system audit							X

Checking of stations	Checking interval						
	1 mo	3 mo	6 mo	1 yr	3 yr	5 yr	When required
General tightness	X						
Telecommunication system	X						
Record measurements gas detector	X						
Emergency shutoff valve			X				
Valves, control valves, etc.				X			
Cleaning filter				X			
Safety valve (if any)					X		
Cleaning and repainting piping			X				
Calibration of flowmeters						X	

Safety management system	Checking interval

	1 mo	3 mo	6 mo	1 yr	3 yr	5 yr	When required
Training of personnel				X			
Emergency response plan-test and update				X			
Audit safety management system						X	
Leak detection system - test				X			
Information to authorities					X		

Appendix B—Damage mechanisms (Informative)

B1 Hydrogen embrittlement

Hydrogen embrittlement is the generic term encompassing all of the detrimental effects that engineered alloys might experience due to the interaction with atomic hydrogen. Some of the effects are more serious than others. Materials variables and actual service conditions affect the appearance of the various hydrogen embrittlement modes. For more information on hydrogen embrittlement and other damage mechanisms, see API 571 [25].

A number of test methods are available to evaluate the suitability of material to resist hydrogen embrittlement (see ISO 11114-4*, Transportable gas cylinders — Compatibility of cylinder and valve materials with gas contents, Part 4: Test methods for selecting steels resistant to hydrogen embrittlement),* some make use of fracture mechanics specimens, others of tensile test or disk specimens [51].

In the presence of hydrogen gas (or another gas bearing hydrogen), a material can experience reduced mechanical properties (e.g., tensile strength, ductility, fracture toughness, fatigue crack growth rate). This phenomenon is generally more pronounced around room temperature for usual metallic materials such as ferritic steels, and disappears rapidly above 150 °F (66 °C). It does not apply for steels greater than 302 °F (150 °C) but could then be replaced at high temperature by hydrogen attack.

In general, the degradation of the mechanical properties of materials is greatest when the strain rate is low and the hydrogen partial pressure and purity are high. However, it should be noted that even a very small amount of hydrogen can severely degrade mechanical properties; see ASME PVP2018-84658 [52]. Under the conditions most appropriate to the operation of a hydrogen-containing gas transmission pipeline, it is generally believed that the gas is dry. Fatigue is not supposed to be a problem, and species that contribute to environmental aggressiveness are not supposed to be present. Nevertheless, the following should be considered when dealing with hydrogen-containing gas pipeline systems: reduction of fracture toughness, reduction of the tensile strength/ductility and notched tensile strength, reduction of fatigue endurance limits, and accelerated fatigue crack growth.

B2 Stress corrosion cracking of line pipe steel in underground environments

SCC of carbon/low alloy steel line pipe in underground environments from both anodic stress corrosion and/or hydrogen embrittlement mechanisms has been reported. This is usually an external corrosion phenomenon and is not influenced by the hydrogen gas being transported. Careful alloy selection, controlled alloy chemistries, and controls over manufacturing processes help mitigate this risk. Poor cathodic protection practices could contribute to the embrittlement mechanism.

B3 Stress corrosion cracking in carbon monoxide environments

It is generally accepted that SCC in carbon monoxide environments is a true SCC process under anodic control. Hydrogen reactions do not play a role in crack initiation and propagation.

SCC requires the simultaneous presence of tensile stresses either residual or directly applied and a susceptible environment. The simultaneous presence of carbon monoxide, traces of carbon dioxide, and traces of water at temperatures less than the dew point provides a susceptible environment for SCC in using carbon and low alloy steels. In pure carbon monoxide environments, carbon dioxide and water species can under certain circumstances be present as contaminants.

Manufacturing or heat treatment procedures that reduce residual tensile stresses mitigate SCC. In this regard, postweld heat treatment is beneficial in reducing SCC susceptibility should liquid water be present. Cleaning, operational, and component assembly procedures that minimize water and carbon dioxide presence are beneficial.

Generally, carbon monoxide SCC does not occur as long as the pipeline is dry.

B4 Inhibiting effects of carbon monoxide in hydrogen environments

It has been established that carbon monoxide present in syngas inhibits hydrogen embrittlement cracking. Other gas impurities including oxygen, carbon disulfide, and sulfur dioxide also have an inhibiting effect. When high carbon monoxide concentrations are present, it is still considered prudent to avoid the use of high-strength steels. Generally, moderate-strength steels are adequate for the pressure and structural requirements and are resistant to hydrogen embrittlement should an unplanned exposure to hydrogen gas occur.

B5 Carbonyl formation

Iron and nickel carbonyls are formed by the action of carbon monoxide upon alloys that contain iron and nickel. The presence of iron and/or nickel carbonyl in process gases can attack the pipeline material, but carbonyl formation reaction rates are generally low enough that pipeline structural integrity is not affected even after long-term service.

Appendix C—Additional codes, standards and guidelines (Informative)

Table C-1 and the Electrical hazardous area requirements section summarize additional codes, standards, and guidelines that may be applicable to hydrogen, carbon monoxide, and syngas pipelines.

Table C-1—Codes, standards, and guidelines applicable to hydrogen, carbon monoxide, and syngas pipelines

Title	Applicability	Description
Pipeline Codes		
API RP 1102, *Steel pipelines crossing railroads and highways* [53]	Welded steel pipelines crossing under railroads and/or highways	Covers the design, installation, inspection, and testing of welded steel pipelines under railroads and highways.
ASME B31G, *Manual for determining the remaining strength of corroded pipelines* [54]	All pipelines and piping systems that are part of ASME B31, *Code for Pressure Piping* [55], i.e., • ASME B31.4 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* [56]; • ASME B31.8 [24]; • ASME B31.11, *Slurry Transportation Piping Systems* [57]; and • ASME B31.12, *Hydrogen Piping and Pipelines*, Part PL [58].	Provides guidance in the evaluation of metal loss in pressurized pipelines and piping systems.
EN 10204, *Metallic products: types of inspection documents* [59]	All metallic products (e.g., plates, sheets, bars, forgings, castings), whatever their method of production. May also apply to nonmetallic products.	Specifies the different types of inspection documents supplied to the purchaser, in accordance with the requirements of the order, for the delivery of all metallic products, whatever the method of production. The standard is used in conjunction with the product specifications, which specify the technical delivery conditions of the products.
ISO 15257, *Cathodic protection - Competence Levels and Certification of Cathodic protection Personnel* [60]	Personnel working in the field of cathodic protection. Certification bodies, delegated bodies, training centers, and examination centers associated with training or certifying cathodic protection personnel.	Defines five levels of competence for persons working in the field of cathodic protection, including survey, design, installation, testing, maintenance, and advancing the science of cathodic protection. It specifies a framework for establishing these competence levels and their minimum requirements.
ISO 3183, *Petroleum and natural gas industries—Steel pipe for pipeline transportation systems* [61]	Seamless and welded steel pipes used in pipeline transportation systems in the petroleum and natural gas industries.	Specifies the requirements for the manufacture of product specification levels PSL 1 and

Title	Applicability	Description
		PSL 2 seamless and welded steel pipes.
ISO 12944-5, *Paints and varnishes — Corrosion protection of steel structures by protective paint systems, Part 5: Protective paint systems* [62]	Steel structures in different environments.	Describes the types of paint and paint system commonly used for corrosion protection of steel structures. Provides recommended paint specification film thicknesses, which experience has shown can give acceptable standards of corrosion protection.
ISO 13623, *Petroleum and natural gas industries—Pipeline transportation systems* [63]	Pipeline systems used for transportation in the petroleum and natural gas industries.	Specifies the requirements and gives recommendations for the design, materials, construction, testing, operation, maintenance, and abandonment of pipeline systems.
ISO 15589-1, *Petroleum, petrochemical and natural gas industries—Cathodic protection of pipeline systems, Part 1: On-land pipelines* [64]	Cathodic protection systems for on-land pipelines.	Specifies requirements and gives recommendations for pre-installation surveys, design, materials, equipment, installation, commissioning, operation, inspection, and maintenance of cathodic protection systems.
ISO 15590-1, *Oil and gas industries including lower carbon energy — Factory bends, fittings and flanges for pipeline transportation systems* *Part 1: Induction bends* [65]	Induction bends made from seamless and welded pipe of unalloyed or low-alloy steels for use in pipeline transportation systems for the petroleum and natural gas industries as defined in ISO 13623 [63].	Specifies the technical delivery conditions for bends made by the induction bending process.
ISO 17636-1, *Non-destructive testing of welds — Radiographic testing* *Part 1: X- and gamma-ray techniques with film* [66]	Applies to the joints of plates and pipes.	Specifies techniques of radiographic examination of fusion welded joints in metallic materials using industrial radiographic film techniques. Does not specify acceptance levels for any of the indications found on the radiographs.
Electrical Hazardous Area Codes		
API RP 500, *Classification of Locations for Electrical Installations at Petroleum Facilities Class* [67]	Petroleum refineries, production and drilling areas, and pipeline stations.	Provides guidelines for classifying locations for the selection and installation of electrical equipment.
European Directive ATEX 2014/34/EU on the harmonization of the laws of the Member States relating to equipment and protective systems intended for	Equipment operating in potentially explosive atmospheres.	Specifies requirements for equipment and protective systems intended for use in explosive atmospheres.

Title	Applicability	Description
use in potentially explosive atmospheres [9]		
European Directive ATEX 199/92/EC on minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres [68]	Facilities that contain potentially explosive atmospheres.	Establishes requirements for protection of workers potentially at risk from explosive atmospheres.
IEC 60079 series of standards [69]	Equipment intended for use in explosive atmospheres.	Specifies the construction and testing of intrinsically safe equipment intended for use in explosive atmospheres.
NFPA 2 [34]	Hydrogen facilities (production, transport, and use).	Specifies safeguards for generation, installation, storage, piping, use, and handling of hydrogen in gas or liquid form.
NFPA 496, *Standard for purged and pressurized enclosures for electrical equipment* [70]	Electrical equipment enclosures.	Provides methods for purging and pressurizing electrical equipment enclosures to prevent ignition of a flammable atmosphere.
NFPA 497, *Recommended practice for the classification of flammable liquids, gases, or vapors and of hazardous (classified) locations for electrical installations in chemical process areas* [71]	Electrical installations in process areas with flammable liquids, gases, and vapors.	Guidelines on classification of flammable liquids, gases, and vapors and of hazardous locations for electrical installations in chemical process areas.

Electrical hazardous area requirements

As hydrogen, carbon monoxide, and syngas systems can pose a fire or explosion risk, electrical systems shall be in accordance with the applicable codes. These provide requirements and suggestions for determining the level of hazard (classification) and mitigating the risks involved. Typically used codes are:

At a minimum, either NFPA 70 or IEC 60079 series of standards should be used [7, 69].

The type of electrical equipment that can be installed and the installation methods depend upon the level of hazard classification and are described in the prescriptive sections of the codes.

It is worth noting that the equipment and piping should be carefully bonded and grounded to drain static electricity and to carry electrical fault currents to earth/ground to prevent the release of electric sparks, which could ignite hydrogen, carbon monoxide, and syngas leaks in the area.