Requirements and Procedures for Pipelines

December 2005

Alberta Energy and Utilities Board

GUIDE RENAMED AS A DIRECTIVE

As announced in *Bulletin 2004-02: Streamlining EUB Documents on Regulatory Requirements*, the Alberta Energy and Utilities Board (EUB) will issue only "directives," discontinuing interim directives, informational letters, and guides. Directives set out new or amended EUB requirements or processes to be implemented and followed by licensees, permittees, and other approval holders under the jurisdiction of the EUB.

As part of this initiative, this document has been renamed as a directive. As well, changes have been incorporated reflecting the compliance assurance process introduced with *Directive 019: Compliance Assurance—Enforcement*. However, no other changes have been made. Therefore, the document text continues to have references to "guides." These references should be read as referring to the directive of the same number. When this directive is further amended, these references will be changed to reflect their renaming as directives.

ALBERTA ENERGY AND UTILITIES BOARD
Directive 066: Requirements and Procedures for Pipelines

December 2005

Replaces Guide 66: Pipeline Inspection Manual (November 2001)

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1 Overview

1.1 Purpose of the Directive

Directive 066: Requirements and Procedures for Pipelines is designed to ensure that EUB Field Centre staff carry out pipeline project inspections in a consistent manner throughout Alberta. The directive and check sheet are also intended to inform industry personnel about what is required to achieve a satisfactory EUB inspection.

The directive is primarily addressed to Field Centre inspectors. It is also intended for use by industry as a guide to what they can expect during a pipeline inspection.

1.2 What This Directive Contains

This directive describes the role of the EUB Field Centre inspectors and includes the EUB check sheet that inspectors complete for each pipeline project inspected, accompanied by a step-by-step description of how to complete each part of the form.

There are two appendices:

1) Operational Deficiencies, detailing criteria for determining the level of noncompliance
2) The EUB Pipeline Inspectors' Guide to Corrosion Failure Procedures

1.3 The EUB Inspector's Conduct

The purpose of pipeline project inspections is to achieve compliance with EUB regulations and ensure safe and efficient practices at all pipeline projects.

EUB Field Centre inspectors represent the EUB and must display a positive attitude and fairness to all operators, which requires job knowledge and the willingness to "find out" when uncertainty occurs.

Inspectors must offer the operator the opportunity to be present prior to and during a hands-on or active inspection that includes opening and closing valves.

For safety reasons inspectors must contact the operator prior to entering sour facilities.

Inspectors must comply where possible with company policies whenever the company requires notification prior to inspection or lease entry or if the inspection involves the use of specific safety equipment.

Inspectors must always use a cooperative approach as the first method attempted to achieve company compliance with EUB regulations. Where practical, they should have a brief discussion with the company's senior personnel on site after the inspection. This opportunity should be used to establish contacts, exchange information, discuss deficiencies, enforcement, and follow-up, and enhance relations.

Each inspector must have a copy of this inspection manual on site when conducting an inspection.

1.4 Safety

Inspectors must refer to the EUB *Internal Guide 8: Safety Manual* prior to inspection of any facility and be sure to follow all requirements.

They should point out any unsafe operating conditions and practices to the operator. If necessary, the inspectors must also advise Alberta Human Resources and Employment, Workplace Health and Safety (formerly OH&S), and/or Alberta Municipal Affairs, Safety Services (formerly Electrical Protection).

1.5 Industry Compliance

The EUB believes that compliance in meeting or exceeding regulations and standards is the responsibility of the energy industry. The EUB expects all industry participants to understand its requirements and have an infrastructure in place to ensure compliance. However, the EUB also recognizes that on occasion enforcement of regulations will be required to ensure compliance.

The EUB has implemented a three-level enforcement policy to address the business issue of noncompliance with provincial requirements. *Directive 019: EUB Compliance Assurance—Enforcement* defines the enforcement consequences when operators fail to meet requirements and/or regulations. These consequences only escalate to a higher severity when the operator fails to address EUB requirements and requests.

The criteria for determining the level of noncompliance are given in Appendix 1: Operational Deficiencies. EUB Field Centre inspectors follow these criteria when completing the Pipeline Check Sheet and determining the resulting enforcement action.

1.6 Exemptions

Exemptions to the Pipeline Act and Regulation and CSA standards must be approved by the EUB.

2 Inspection Guide and Check Sheet

EUB Alberta Energy and Utilities Board

Pipeline Check Sheet

A. PIPELINE IDENTIFICATION

LICENSEE NAME ☐ LICENSEE CODE ☐ LICENCE NUMBER ☐ FILE/ENV NUMBER ☐ LINE NUMBERS ☐

LICENSEE REPRESENTATIVE ☐ PHONE NUMBER ☐ CONSTRUCTION CONTRACTOR ☐ STARTING (FROM) LOCATION ☐ INSTALLATION NUMBERS ☐

B. INSPECTION DETAILS

INSPECTION DATE ☐ INSPECTOR NAME ☐ FIELD CENTRE ☐

TYPE OF INSPECTION
- ☐ Construction
- ☐ Test
- ☐ Operations
- ☐ Failure/Hit

☐ FAILURE/HIT CAUSE CODE

☐ INITIAL INSPECTION
☐ REINSPECTION

☐ SUBSTANCE

☐ INVESTIGATION COMPLETION DATE

C. INSPECTION RESULTS (Code: Satisfactory "X"; Low Risk Unsatisfactory "L"; High Risk Unsatisfactory "H")

PIPELINE SPECIFICATIONS
1 ☐ Substance
2 ☐ H_2S Content
3 ☐ Outside Diameter
4 ☐ Wall Thickness
5 ☐ Materials Used
6 ☐ Type and Grade
7 ☐ Joint Type
8 ☐ Internal Coating
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10 ☐ From and To Facilities
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61 ☐ Compressor/Oil Pump Station Identification
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63 ☐ Right-of-Way
64 ☐ Pressure Control Devices or Pressure Relief Devices
65 ☐ Surface Pipeline
66 ☐ *Guide 55* Storage Requirements

INCIDENT CAUSE
67 ☐ Failure/Hit
68 ☐ Spill

OTHER (Y/N)
69 ☐ *Guide 58* Waste Management Requirements Met?
70 ☐ Facility Suspended?
71 ☐ Letter to Licensee Required?
72 ☐ Records Review of Licensee Compliance?

OVERALL INSPECTION RESULT ☐ Satisfactory ☐ Unsatisfactory

ENFORCEMENT ACTION
Satisfactory Inspection (no action required) ☐
Unsatisfactory Inspection ☐
Noncompliance Level:____________________
Consequences of Noncompliance:___________

D. COMMENTS

____
____
____
____
____

Licensee's Signature ______________________________ Inspector's Signature ______________________________

Deadline Date ______________________________

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2 Inspection Guide and Check Sheet

2.1 When to Use the Check Sheet

The EUB inspector must complete a Pipeline Check Sheet when conducting a construction, test, operations, or failure/hit inspection.

The inspector must also complete a check sheet if a pipeline is inspected due to a complaint, notification, or incident.

2.2 How to Complete the Check Sheet

Note that the check sheet is in abbreviated format: each item on the form may require several items to be inspected.

Record unsatisfactory item(s) in the appropriate box. Not all items on the check sheet must be inspected during every inspection. Mark only those items that are physically inspected.

This check sheet is used as a written record of every inspection and for input into the EUB's computer database. Complete a separate check sheet for each licence and file number that is inspected during construction inspections and for every licence during operations or failure/hit inspections.

Leave a copy of the inspection form with the operator after each inspection. If no operator is on site, send the inspection form to the licensee.

A Pipeline Identification

Licensee Name — Enter the complete name of the licensee.

Licensee Code — Enter the licensee's code.

Licence Number — Enter the applicable licence number.

File/ENV Number — Enter the file number assigned to the licence or the ENV Event Key number for failures/hits. (See Field Surveillance ENV Completions internal guide.)

Line Numbers — Enter only the specific line numbers inspected.

Installation Numbers — Enter the installation numbers (from the EUB database) of installations inspected that are associated with the licence.

Licensee Representative — Enter the name of the licensee's representative.

Phone Number — Enter the telephone number, including area code, of the licensee's representative.

B Inspection Details

Inspection Date	Enter the date of inspection.
Inspector Name	Enter the name of the EUB inspector.
Field Centre	Enter the name of the inspector's EUB Field Centre.
Type of Inspection	Check the appropriate box(es) that indicates the type(s) of inspection being conducted.
Failure / Hit Cause Code	Enter the applicable incident cause code. For corrosion failures, see Appendix 2 for the necessary procedures to follow.
Initial Inspection or Reinspection	Check the appropriate box that indicates if the inspection is an initial one or a reinspection.
Substance	Enter the applicable code from the licence for the substance that the pipeline transports.

C Inspection Results

All items inspected, except those in the "Other" category, must be marked "X" for satisfactory, "L" for low risk unsatisfactory, or "H" for high risk unsatisfactory. Items under "Other" must be marked "Y" for yes or "N" for no. See *Directive 019* for details on consequences for low and high risk noncompliances. See Appendix 1 for operational deficiencies.

Pipeline Specifications

1. Substance	The substance code on the licence is that of the substance being transported in the pipeline. See *Guide 56*, Unit 3, Table 3.1. By definition, each licence is substance specific. For example, there cannot be a saltwater line and an oil effluent line on the same licence.
2. H_2S Content	The hydrogen sulphide (H_2S) content is equal to or less than that stated on the licence. If any (H_2S) is being transported in the gas, calculate the partial pressure to see if the pipeline must be built to conform to sour specification. The partial pressure is determined by multiplying the mole (mol) fraction of H_2S in the gas phase by the maximum operation pressure (MOP) in kilopascals (kPa). The partial pressure of H_2S in the gas phase determines if sour service materials are required.

For gas pipelines, sour service materials are required if the partial pressure of H_2S in the gas phase exceeds 0.35 kPa.

For multiphase pipelines (oil-well effluent), sour service materials are required if the combination of H_2S in the gas phase is in accordance with either of the following:

- the system pressure is < 1400 kPa and the H_2S content in the gas phase is > 50 mol/kmol, or
- the system pressure is >1400 kPa and the partial pressure of the H_2S in the gas phase is >70 kPa.

If the pipeline is transporting more than 10 moles of H_2S per kilomole of natural gas, certain other requirements must be looked at, adhering to *Interim Directive (ID) 81-3* setback requirements. General design and material requirements are found in *CSA Standard Z662,* Clauses 4 and 5; Pipeline Regulation, Section 13; and *Guide 56*, Schedule 3.

3. Outside Diameter

The outside diameter of the pipe is that stated on the licence.

The outside diameter can be found stencilled on the outside of the pipe coating, as required by *CSA Standard Z245.1*.

4. Wall Thickness

The wall thickness of the pipe is that stated on the licence.

The wall thickness can be found stencilled on the outside of the pipe coating, as required by *CSA Standard Z245.1*.

Wall thickness for repairs and crossings may vary, provided that the minimum requirements in CSA and the regulations are met.

5. Materials Used

Materials used are those stated on the licence (*Guide 56*, Table 3.2; Pipeline Regulation, Section 2(1)).

6. Type and Grade

The pipe type and grade are those stated on the licence (*Guide 56*, Tables 3.3, 3.4, 3.5, and 3.6).

“Type” is the standard to which the pipe was manufactured (API, ASTM, or CSA).

“Grade” is the specification of the material used in the pipe. Mill certificates certifying pipe as meeting a specified grade for the pipe supersede stencilling on pipe.

Type and grade for repairs and crossings may vary, provided that the minimum requirements in CSA and the regulations are met.

7. Joint Type

The joint type is that stated on the licence (*Guide 56*, Table 3.7).

8.	Internal Coating	The internal coating is as approved on the licence (*Guide 56*, Table 3.8).
9.	From and To Locations	The “from” and “to” locations of the pipeline being built are those stated on the licence (Pipeline Regulation, Section 3(1)).
10.	From and To Facilities	The facilities the pipeline is going from and to are those stated on the licence (*Guide 56*, Table 3.9).
11.	Length of Pipeline/Route	The length of the pipeline and its route correspond to what is stated on the licence (Pipeline Regulation, Section 3(1)). The actual route of the pipeline being built corresponds to that stated on the licence (Pipeline Regulation, Section 3(1)).
12.	Environment	The actual environmental crossing of the pipeline corresponds to that represented by the environment code stated on the licence (*Guide 56*, Table 3.11). Confirm that all necessary approvals have been obtained from Alberta Environment (*Guide 56*, Unit 3, Step 10).
13.	MOP	Specifications for valves, flanges, fittings, and pipe are compatible with the licensed MOP (Pipeline Regulation, Sections 9, 10 and 19(1)). If two or more pipelines are connected, see Pipeline Regulation, Sections 9 and 10.

Construction

14.	Construction Approval	The operator holds the necessary EUB approval, in accordance with the Pipeline Act, Part 4, Section 7, which states that no person shall construct a pipeline or undertake any operations preparatory or incidental to the construction of a pipeline unless he is the holder of an approval. (Also see *Guide 56.*) All rights-of-way must be surveyed according to the Survey Act and all notification requirements must be met, as described in *Guide 56*, Table 1.3, Schedule 1, and Appendix 1. An application is not required if • the pipeline is used for a utility cooperative pipeline and is operated at a maximum pressure of 700 kPa or less; • the pipeline replacement is less than 100 metres (m) long, the replaced pipeline is removed, and the work is carried out within the existing right-of-way; • the total pipeline is less than 50 m long and does not convey natural gas > 10 mol/km H_2S;

- a pipeline or tie-in is wholly within a single surface lease boundary, **except when**
  - the pipeline route is within the access road to a well site or
  - the pipeline conveys high vapour pressure (HVP) or natural gas containing > 10 mol/km H_2S.

15. Construction Notice Received

The required 24-hour construction notice has been given to the appropriate Field Centre prior to the start of construction of any pipeline (Pipeline Regulation, Section 17).

16. Conditions

The company has complied with all conditions stated on the licence (Pipeline Act, Section 11).

17. Valves/Fittings/Flanges

All valves, fittings, and flanges have a manufacturer's rating equal to or greater than the proposed MOP of the pipeline (Pipeline Regulation, Section 10).

If used in sour service, the valves, fittings, and flanges must meet the requirements set out in the respective *CSA Standards Z245.15*, *Z245.11*, and *Z245.12* respectively.

All bolt studs extend completely through the nuts on flange installations (*CSA Standard Z662*, Clauses 5.2 and 5.3).

Sectionalizing valves are installed on both sides of major water crossings and other locations appropriate for the terrain (HVP and low vapour pressure [LVP] only) (*CSA Standard Z662*, Clause 4.4.8).

Sectionalizing block valves are installed at spacings commensurate with class locations (*CSA Standard Z662*, Clause 4.4.4 and Table 4.6; Pipeline Regulation, Section 10; *IL 91-8*):

- 25 km for Class 2 Gas
- 13 km for Class 3 Gas
- 8 km for Class 4 Gas
- 15 km for Class 2 HVP or carbon dioxide (CO_2)
- 15 km for Class 3 HVP or CO_2
- 15 km for Class 4 HVP or CO_2

Valve spacing variance should not normally exceed 25 per cent of the applicable distances listed above.

18. Road Crossing Pipe Specifications

Road and highway crossing pipe specifications are at least to minimum standards and extend to the full width of the right-of-way of the highway or road (*CSA Standard Z662*, Clause 4 and Tables 4.8 and 4.9, and Clause 6.2.10; Pipeline Act, Sections 39(1,2,3,4) and 40; Pipeline Regulation, Section 16(1,2)).

A "highway" is a primary roadway within the meaning of the Public Highways Development Act or a secondary road within

		the meaning of the Public Highways Development Act numbered between 900 and 999, Pipeline Act 11F (Pipeline Regulation, Section 18(1a,1b,1c,2)).
19.	Railway Crossing Pipe Specifications	Railway crossing pipe specifications are at least to minimum standards (*CSA Standard Z662*, Clauses 4.8.3 and 6.2.10).
20.	Depth of Cover	Depth of cover meets the minimum requirements of *CSA Standard Z662*, Clause 4 and Table 4.8; and Pipeline Regulation, Sections 18 and 19.
21.	Ditch Preparation	The pipeline ditch is free of any projections or materials that may damage the pipe or coating during lowering in or back filling (*CSA Standard Z662*, Clauses 6.2.6, 13.3.4.6, and 13.1.4.4).
22.	Joining/Inspection and Testing	Methods of joining pipe are in accordance with applicable standards and regulations (*CSA Standard Z662*, Clauses 6.2, 7.2, and 7.2.8 [steel], 13.1.5 [fibreglass], 12.7 [polyethylene gas distribution], 13.3.5 [polyethylene oilfield], 7.4.2 [mechanical interference fit joints], 4.5.2 [threaded]). For joint codes, see *Guide 56*, Table 3.7. Thermoplastic pipe joints have CSA certification (*CSA Standard B 137.4*). Inspection and testing in accordance with *CSA Standard Z662*, Clauses 7.2.8, 7.2.9, 7.2.11, and 7.2.12 where applicable.
23.	Bored Crossings	Bored road, railway, and water crossings have a hole diameter as close as practical to the outside diameter of the carrier pipe (*CSA Standard Z662*, Clause 6.2.10.3).
24.	Pipe Coating/ Condition	Stockpiling, transporting, handling, and placing of the pipe are being done in such a manner as to prevent any damage to the pipe or the coating (*CSA Standard Z662*, Clauses 6.2.5 and 9.2.7).
25.	Backfill Procedures	Precautions are being taken while back filling to prevent any damage to the pipe from rocks or frozen dirt (*CSA Standard Z662*, Clause 6.2.7). Sizing plate runs should be considered if field bends or possible dents from backfilling procedures are suspected. Consideration for wall thickness changes must be addressed (*CSA Standard Z662*, Clauses 6.2.3 and 6.2.7.2). If spoil pile is rocky or in frozen lumps, then rock shield padding or shading the pipe with non-rocky or frozen material is being used (*CSA Standard Z662*, Clause 6.2.7.2).

26.	Lease Piping	All on-lease piping is suitable to withstand the MOP of the pipeline it is connected to (*CSA Standard Z662*, Clause 4). The use of threaded pipe-to-pipe or pipe-to-component connections for buried pipe is **not** permitted (*CSA Standard Z662*, Clause 4.5.2). Supports are designed to support the pipe without causing excessive local stresses and without imposing excessive axial or lateral friction forces that might prevent the desired freedom of movement (*CSA Standard Z662*, Clause 4.6.4). Supports must not be welded to the pipeline if the specified minimum yield strength (SMYS) is greater than 50 per cent (*CSA Standard Z662*, Clause 4.6.5). A pipeline or tie-in is wholly within a single surface lease boundary, **except when** • the pipeline route is within the access road to a well site, or • the pipeline conveys HVP or sour natural gas.
27.	Safety Precautions	All pipeline construction is being done in a safe and efficient manner to ensure the safety of workers and the public (*CSA Standard Z662*, Clause 10.4; Pipeline Act, Part 5, Section 29(1); *IL 92-3*).

Ground Disturbance

28.	Crossing Agreements	The operator has obtained approval in writing from the licensee of an existing pipeline prior to a ground disturbance taking place within the right-of-way of the existing pipeline or within 5 m of an existing pipeline if a right-of-way does not exist (Pipeline Regulation, Sections 20.1 and 22(1)).
29.	Existing Pipelines Marked	The position and alignment of an existing pipeline are marked with clearly distinguishable warning signs at adequate intervals before a ground disturbance takes place in controlled areas (Pipeline Regulation, Section 21(2)). A controlled area extends 30 m on each side of an existing pipeline (Pipeline Regulation, Section 20).
30.	Hand Excavation	Pipelines are hand exposed before any mechanical excavation takes place within 5 m of an existing pipeline (Pipeline Regulation, Section 22(7)).
31.	Machine Within 60 cm	Mechanical excavation equipment is not being used within 60 cm of a pipeline without direct on-site supervision by a representative of the licensee of the existing pipeline (Pipeline Regulation, Section 22(10)).

The pipeline must first be hand exposed or exposed by a method approved by the EUB (e.g., hydrovac, water jet, or other nonmechanical methods).

32.	Notification Prior to Ground Disturbance	Any operator proposing to undertake a ground disturbance in a controlled area has notified the owner of the existing line at least two days and not more than seven days prior to commencing the ground disturbance (Pipeline Regulation, Section 21(1)).
33.	Notification Prior to Backfill	Any operator undertaking a ground disturbance that exposes any part of an existing pipeline has notified the owner of the existing pipeline 24 hours prior to backfilling (Pipeline Regulation, Section 22(5)).

Pressure Testing

34.	Test Notice Received	The appropriate Field Centre must be notified at least 48 hours prior to the commencement of any test (Pipeline Regulation, Section 32(1,2)). Prior to pressure testing, the completed pipe sections have been cleaned of construction debris and foreign matter (*CSA Standard Z662*, Clause 6.2.8).
35.	Test Medium/Disposal	EUB approval is required if • water is the test medium in aluminum pipelines or any liquid other than fresh water is used as a test medium in any pipeline and the volume of the test section exceeds 500 m^3 (Pipeline Regulation, Sections 43 and 44), or • the hoop stress level during the test exceeds 100 per cent SMYS, or the volume of the test section will exceed 3 m^3 and the pipeline crosses or is within 100 m of flowing water and the hoop stress during the test will exceed 30 per cent SMYS (Pipeline Regulation, Sections 43 and 44).
36.	Test Piping	All test piping that is not a permanent part of the pipeline is limited to a test pressure that will result in a hoop stress level not greater than 75 per cent SMYS (*CSA Standard Z662*, Clause 8.9.1). All piping within 20 m from the connection of the test piping is limited to a test pressure that will result in a hoop stress level not greater than 90 per cent of SMYS (Pipeline Regulation, Section 40). All road and railway crossings that will be at 80 per cent SMYS or more during gaseous medium testing must be pretested or the road or the railway must be closed to traffic during the pressure test (*CSA Standard Z662*, Clause 8.2.8).

All valves and fittings on test piping are limited to a test pressure not greater than the manufacturer’s working rating during the test (*CSA Standard Z662*, Clause 8.9.1).

37. Test Under Operating Conditions

Pipelines are tested in place under the same conditions as those that will prevail when the pipelines will be in operation (Pipeline Regulation, Section 29). (The line should be backfilled prior to testing unless conditions apply as outlined in *CSA Standard Z662*, Clauses 8.1.2 and 8.1.3).

Tie-in welds between tested sections for pipelines operating at stresses of 30 per cent SMYS or greater are to be radiographically or ultrasonically inspected until found to be satisfactory, unless the tie-in welds will be subjected to a pressure test (*CSA Standard Z662*, Clause 7.2.8.2.1).

In the case of a sour service pipeline (refer to Section 2 of this directive), the tie-in welds are radiographically inspected irrespective of stress levels (*CSA Standard Z662*, Clause 7.2.8.2.2).

38. Safety Precautions

Testing is done in a manner that ensures the protection of persons and property in the vicinity of the pipeline (Pipeline Regulation, Section 30).

39. Pressure Test

All pressure tests are recorded on a chart unless otherwise allowed by the EUB (*CSA Standard Z662*, Clause 8.6; Pipeline Regulation, Section 35(1)).

Upon completion of any pressure test, results are recorded.

The location and specifications of the tested pipeline or part of the pipeline are identified by reference to an existing plan, as well as an elevation profile where necessary, as outlined in the Pipeline Regulation, Section 37.
The final documentation contains the following information:

- Company name
- Approval number
- Line number and/or section number
- Legal description
- Date
- Time on and off
- Test medium
- Gauge pressure
- Recorder range on chart face
- Significant pressure deviations reconciled by documentation

40.	Pressure Reading Between 25 and 90 per cent	The instrument used to record the pressure during the test is selected so that the pressure reading occurs between 25 and 90 per cent of the full range of the instrument (Pipeline Regulation, Section 35(3)). Each pressure-recording instrument is periodically calibrated to maintain accuracy within 2 per cent of its range. The EUB may require verification of such calibration (Pipeline Regulation, Section 35(4,5); *CSA Standard Z662*, Clauses 8.6.1, 8.6.2, and 8.6.2.4).
41.	Test Pressure/Duration	Test pressure is adequate for the MOP of the pipeline; permissible stress levels during the test are not exceeded (Pipeline Regulation, Section 39(1)). Testing with non-toxic gas is permitted in Class 1 areas up to 95 per cent SMYS (Pipeline Regulation, Section 45). For additional requirements for gaseous air testing, see *CSA Standard Z662*, Clauses 8.2.2, 8.2.4.3, 8.2.6.3, and 8.2.8. Maximum strength test pressure for liquid medium is 110 per cent SMYS (*CSA Standard Z662*, Clause 8.2.4.2) or limit reached by a pressure volume plot. Sour natural gas pipelines (greater than 10 moles of H_2S per kilomole of natural gas) for all class locations are tested to minimum 1.40 x MOP (Pipeline Regulation, Section 41(3)). A testing procedure is approved and a pressure/volume plot is conducted whenever the pipeline is pressure tested above 100 per cent SMYS (Pipeline Regulation, Section 39(1)). The test pressure of any pipeline must not be less than 700 kPa unless the EUB approves a lower test pressure (Pipeline Regulation, Section 41(2)). The MOP is in accordance with *CSA Standard Z662*, Table 8.1. • Note that Pipeline Regulation, Section 41(3), supersedes Table 8.1 for sour natural gas. Pressure tests of lease piping are adequate for the MOP of the connecting pipeline. • Note that testing against a closed valve is not recommended. Pressure test can be conducted up to 1.5 times the rating of the valve or flange. See *CSA Standard Z662*, Clause 8 and Table 8.1, and Pipeline Regulation, Sections 6, 39, 40, 41, 45, and 46.

Discontinued Pipeline

42.	Physically Isolated/ Disconnected	The discontinued line or part of a pipeline is physically isolated or disconnected from any operating facility (*CSA Standard Z662*, Clause 10.13; Pipeline Regulation, Section 61(a,b,c,d); *ID 2000-9*; *Guide 56*). Pipelines that have not been in normal operation within the previous 12 months must have EUB consent to resume operation (Pipeline Regulation 64). These pipelines should be scrutinized to ensure that proper corrosion mitigation procedures have been in place.
43.	Left in Safe Condition	The discontinued pipeline is left in a safe condition (Pipeline Regulation, Section 61(a,b,c,d)). "Safe condition" means that there is no opportunity for explosive, flammable, poisonous, or environmentally damaging gases, liquids, or vapours to be emitted if the pipeline is damaged by any means.
44.	Corrosion Control	Corrosion control measures are maintained on discontinued pipelines (*CSA Standard Z662*, Clauses 9 and 10.13.1.2; Pipeline Regulation, Section 62).

Abandoned Pipeline

45.	Physically Isolated/ Disconnected	The abandoned pipeline is physically isolated or disconnected from any operating facility (*CSA Standard Z662*, Clauses 10.14.1 and 10.14.2; Pipeline Regulation, Section 67(1a,1b,1c,1d); *ID 2000-9*; *Guide 56*).
46.	Cleaned/Purged	The abandoned pipeline is cleaned if necessary and purged with fresh water, air, or inert gas and left in a safe condition (*CSA Standard Z662*, Clause 10.14.2; Pipeline Regulation, Section 67). "Safe condition" means that there is no opportunity for explosive, flammable, poisonous, or environmentally damaging gases, liquids, or vapours to be emitted if the pipeline is damaged by any means.
47.	Plugged/Capped	The abandoned pipeline is plugged or capped at all open ends (*CSA Standard Z662*, Clause 10.14.2; Pipeline Regulation, Section 67).

Operations Review

48.	Operations and Maintenance Procedures	The company has documented an operations and maintenance procedure for its pipeline system (*CSA Standard Z662*, Clause 10.2.1.1; Pipeline Regulation, Section 49).

		The company must • document operating and maintenance procedures; • operate and maintain its pipeline system in conformance with such procedures; and • modify such procedures from time to time as experience dictates and as changes in operating conditions require.
49.	Emergency Procedures Manual	A licensee of a pipeline transporting gas containing 10 or more moles of H_2S per kilomole of natural gas or a liquid-filled pipeline transporting an HVP liquid must maintain an emergency procedures manual (*CSA Standard Z662*, Clause 10.4.10; Pipeline Regulation, Sections 50(1a,1b,1c,1d, 1e) and 50(2)). The licensee of a pipeline transporting HVP liquids must periodically conduct emergency exercises structured to test the licensee's internal capabilities for initial response to the emergency procedures described in the manual and to test any leak detection and supervisory control and data acquisition systems associated with the pipeline (*CSA Standard Z662*, Appendix E; Pipeline Regulation, Section 50(3)). The company must retain a record describing the results of the emergency exercise for a period of two years from the time of the exercise (Pipeline Regulation, Section 5(1)(d)). The emergency procedures manual must be updated at least once each year (Pipeline Regulation, Section 50(2)).
50.	Pressure Test Data Records	All original and follow-up test data results, including any pressure, temperature, or pressure-volume plots, and other documentation must be retained by the licensee for the operating life of the pipeline (*CSA Standard Z662*, Clause 8.6.2).
51.	Internal Corrosion Control	Appropriate methods to detect and mitigate internal corrosion are employed to protect pipelines transporting any liquid or gas or combination thereof that may cause the interior to corrode (*CSA Standard Z662*, Clause 9; Pipeline Regulation, Section 53(a,b,c). Each licensee must monitor to determine the effectiveness of mitigation procedures (*CSA Standard Z662*, Clauses 9.4.3 and 9.5). The results of the inspection or tests must be recorded and retained for a minimum of six years (Pipeline Regulation, Section 53).
52.	External Corrosion Control/ Cathodic Surveys	Each buried steel or aluminum pipeline must have an external protective coating and be cathodically protected in its entirety

within one year following completion of construction (*CSA Standard Z662*, Clauses 9.2.1.2 and 9.2.2; Pipeline Regulation, Section 52(1,2a,2b,2c)).

For existing bare piping, refer to *CSA Standard Z662*, Clause 9.2.3.

Each licensee must conduct an annual inspection or test to determine the effectiveness of external corrosion mitigation procedures on all steel and aluminum lines in its pipeline system (Pipeline Regulation, Section 52(1)).

53. Failure/Repair Records

A licensee must retain a record of all leaks for the life of the pipeline system (*CSA Standard Z662*, Clause 10.3.4; Pipeline Regulation, Section 55(1,2)).

54. Failure Notification

When a leak, break, or contact damage occurs in a pipeline, the licensee must immediately inform the EUB of the location of the leak, break, or contact damage (Pipeline Act, Section 36 (1) and 36 (1.1).

55. Crossing Agreements

If a ground disturbance is to take place in the right-of-way of a pipeline or within 5 m of a pipeline where there is no right-of-way, the licensee has an approval in writing (Pipeline Regulation, Section 22(1)).

56. Crossing Inspection Record

A licensee of an existing pipeline who has been notified of a proposed ground disturbance must

- inspect its pipeline before the start of the ground disturbance to ensure that the locating and marking have been properly carried out; and
- carry out such inspections of the ground disturbance necessary to ensure the continued safety of the pipeline (Pipeline Regulation, Section 22(3)(a)(b)).

The licensee must inspect the exposed part of the pipeline before backfilling to ensure that no damage has occurred (Pipeline Regulation, Section 22(5)).

When a licensee inspects a pipeline, a written record of the inspection must be made and retained by the licensee for a minimum of two years (Pipeline Regulation, Section 22(6)).

57. Leak Detection

Leak detection systems must be tested annually to demonstrate continued effectiveness (*CSA Standard Z662*, Clause E4.3). The licensee of a pipeline transporting HVP liquids must periodically conduct emergency exercises (simulation leaks) structured to test the licensee’s internal capabilities for initial response to the emergency procedures described in its

		emergency procedures manual (see item 50) and to test any leak detection and supervisory control and data acquisition systems associated with the pipeline (*CSA Standard Z662*, Clause 10.2.6 and Appendix E; Pipeline Regulation, Sections 6(3) and 50(3)).
58.	Licence Status	The pipeline's operational status is the same as reflected in EUB records: "O" (operational), "D" (discontinued), "A" (abandoned), "R" (removed). The operational status for discontinued/abandoned must be reported to the EUB within 90 days of completion of the work.
59.	Pipeline Crossing Signs	The licensee has erected pipeline warning signs meeting the requirements of the Pipeline Regulation at each side of a crossing where a pipeline crosses a highway, road, railway, or watercourse (Pipeline Regulation, Section 23). Surface lines are buried at all road and trail crossings, and pipeline warning signs are placed at the point of pipeline entry and exit of each crossing (*CSA Standard Z662*, Clause 10.2.9; Pipeline Regulation, Section 19(2,3)).
60.	Aboveground Facility Identification	Warning signs identify all aboveground pipeline facilities and are erected adjacent to the facility in each case (*CSA Standard Z662*, Clause 10.2.8.6; Pipeline Regulation, Sections 24(1,2) and 25). All pertinent data on signs must be accurate.
61.	Compressor/ Oil Pump Station Identification	A large sign showing the name of the facility, the name of the licensee, an emergency telephone number, and a warning symbol is erected at the entrance to gas compressor stations and oil pumping stations (*CSA Standard Z662*, Clause 10.2.9; Pipeline Regulation, Section 25(1); Oil and Gas Conservation Regulations).
62.	Noise Control	Compressor stations and pump stations are operated so that the maximum noise levels are in accordance with EUB *ID 99-8* (Pipeline Regulation, Section 14; *ID 99-8*; *Guide 38*).
63.	Right-of-Way	Operating companies must patrol their pipelines in order to observe surface conditions on and adjacent to their rights-of-way, indications of leaks, construction activity performed by others, and other conditions affecting the safety and operation of the pipelines. Particular attention must be given to the following: a) construction activity b) dredging operations c) erosion d) ice effects e) scour f) seismic activity g) soil slides h) subsidence i) water crossings

Frequency of patrols are in accordance with Pipeline Regulation, Section 14.1 (*CSA Standard Z662*, Clause 10.5).

64.	Pressure Control Devices or Pressure Relief Devices	During the steady-state operation of a pipeline, the operating pressure of the pipeline must not exceed the MOP as per the requirements described in *CSA Standard Z662*, Clause 4.14.1.

If two or more pipelines are connected such that one operates at a pressure higher than the other, they are designed so that the pipeline system operating at the lower pressure is not subjected to a pressure greater than its MOP (*CSA Standard Z662*, Clauses 4.14.2, 4.14.3, and 4.14.4; Pipeline Regulation, Sections 9 and 58).

Pressure control, pressure limiting, and pressure-relieving systems (or devices) must be inspected at least once per calendar year, as detailed in *CSA Standard Z662*, Clause 10.6.5. Records of such tests and inspections and the records of any corrective action taken must be retained by the operating company.

Pipeline valves that might be required during an emergency must be inspected and partially operated at least once per calendar year, as detailed in *CSA Standard Z662*, Clause 10.6.6.2.

65. Surface Pipeline

All surface pipelines have

- a pressure-relieving device if there is any possibility of a pressure increase to above the allowable MOP due to a rise in ambient air temperature;
- a system to allow for adequate expansion or contraction due to temperature change; and
- suitable restraints to adequately control lateral or vertical movement.

Surface lines are buried at all road and trail crossings, and pipeline warning signs are placed at the point of pipeline entry and exit of each crossing.

Additional precautions, such as extra pipeline warning signs, are taken to indicate the presence of a surface line when equipment might be working in the vicinity of the pipeline or conditions might obscure or endanger the pipeline (Pipeline Regulation, Section 19).

66. *Guide 55* Storage Requirements

Record noncompliance on check sheet and specify details in D: Comments section using Appendix 1.

- Appropriate material and waste storage must be conducted in accordance with *ID 95-3* and *Guide 55*. This includes aboveground tanks, underground tanks, containers, storage facilities, bulk pad storage, and inspection, monitoring, and record keeping requirements for those materials produced, generated, or used by the upstream petroleum industry under EUB jurisdiction.

- All facilities constructed after January 1, 1996, must meet the requirements of *Guide 55*.

- Operators of facilities constructed and operated prior to January 1, 1996, are required to demonstrate that their storage practices, facilities, and containment devices meet the requirements of *Guide 55*.

Incident Cause

67. Failure/Hit

If a noncompliance is noted during the failure investigation and records review, record that noncompliance on the check sheet and specify details in D: Comments section using Appendix 1.

All failures/hits must be reported to the EUB in accordance with the Pipeline Act, Sections 36(1) and 36(1.1). Note that Appendix 2 must be followed when dealing with all corrosion-related failures.

Select/failure mechanism from the following list:

CD	Construction damage
MD	Mechanical damage
JF	Mechanical joint failure
CW	Corrosion at girth or fillet weld
CX	Corrosion external
CI	Corrosion internal
DO	Damage by others
EM	Earth movement
GW	Girth weld failure
IF	Installation failure
MJ	Miscellaneous joint failure
MS	Miscellaneous
OE	Operator error
WF	Other weld failure
OP	Overpressure failure
PF	Pipe failure
SR	Seam rupture
VF	Valve or fitting failure
UN	Unknown

68.	Spills	Spill and line failure details are to be recorded on the EUB's ENV form (see Field Surveillance ENV Completions internal guide). This section (69) applies to noncompliance and enforcement of containment and cleanup. Record non-compliance on check sheet and specify details in D: Comments section using Appendix 1. • Immediate steps must be taken to contain and clean up spills of any size or type. The EUB's authority to require and direct cleanup activities where necessary is detailed in the Pipeline Act, Section 37(1). • Spills of refined products on or off lease must be contained and cleaned up in accordance with the guidelines of the Pollution Control Division of Alberta Environment. (See EUB *IL 98-1: Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*.) • The landowner must be advised of any spills off lease or significant spills on lease, and the company must adequately address all concerns.

Other (Enter "Y" for yes, or "N" for no for items 70-73)

69.	*Guide 58* Waste Management Requirements Met?	Enter "N" if the licensee is not in compliance with the requirements of *Guide 58*. See *Guide 64* for enforcement action.
70.	Facility Suspended?	Enter "Y" if the licensee is requested to suspend operations for any length of time (Pipeline Act, Sections 29(1), 30, and 31).
71.	Letter to Licensee Required?	Enter "Y" if a letter is being sent to the licensee. If the overall inspection result is "H" (high risk unsatisfactory), the inspector must send a letter to the licensee stating escalating consequences for noncompliance.
72.	Records Review of Licensee Compliance?	Enter "Y" if a records review of the pipeline inspection system for licensee compliance has been completed. Escalate or remove the licensee from the enforcement ladder based on the inspection history.
Overall Inspection Result		Indicate if the overall inspection is Satisfactory or Unsatisfactory by entering an "X" in the appropriate box. The overall result is Unsatisfactory if any item on the Pipeline Check Sheet is marked Low or High Risk.

D Comments

Clearly define the necessary work that must be completed by the operator in the Comments section.

Enforcement Action

Enter "X" if the inspection is satisfactory.

Enter the appropriate code (U, M, or S) if the inspection is unsatisfactory.

Indicate the appropriate noncompliance level and consequences for noncompliance (see back of check sheet form).

Licensee's Signature

Be sure that the licensee of the inspected facility signs the completed inspection sheet.

Inspector's Signature

As EUB inspector, sign the completed inspection sheet.

Deadline Date

Enter the date by which the necessary work detailed under Comments must be completed.

2.3 Submission of Check Sheet

Give the licensee a copy of the completed check sheet.

File the completed Pipeline Check Sheet with the local Field Centre.

Follow-Up/Reinspections

A reinspection Check Sheet must be completed and entered to clear unsatisfactory inspections from the database.

Appendix 1 Operational Deficiencies

The **level** of each deficiency is based on the criteria set out in *Directive 019: EUB Compliance—Assurance-Enforcement*.

Inspection Results

- **Low Risk unsatisfactory event/inspection (L)** — a contravention of regulation(s) or requirement(s) that represents an acceptable level of risk that requires mitigative measures within an acceptable time frame.
- **High Risk unsatisfactory event/inspection (H)** — a contravention of regulation(s) or requirement(s) that represents an unacceptable level of risk requiring the inclusion of mitigative measures, provided the benefits outweigh the risks.

The EUB may escalate noncompliance issue(s) to any level should conditions warrant.

Compliance and Noncompliance Results

Inspection results are rated "X" **-** satisfactory, "L" – low risk unsatisfactory, and "H" – high risk unsatisfactory. Items below are numbered in accordance with the Pipeline Check Sheet.

Pipeline Specifications

H 1. Substance is different from that stated on licence and the line is operating.

H 2. H_2S content is higher than that stated on licence and the line is operating.

H 3. a. Pressure design does not meet *CSA Standard Z662*, Clause 4.3.3, or Pipeline Regulation, Section 13.

L b. Outside diameter differs from that stated on the licence but meets the pressure design of *CSA Standard Z662*, Clause 4.3.3, or Pipeline Regulation, Section 13.

H 4. a. Pressure design does not meet *CSA Standard Z662*, Clause 4.3.3, or Pipeline Regulation, Section 13.

L b. Wall thickness differs from that stated on the license but meets the pressure design of *CSA Standard* Z662, Clause 4.3.3, or Pipeline Regulation, Section 13.

H 5. Materials used: Pipe material is not as stated on the licences.

H 6. a. Pressure design does not meet *CSA Standard Z662*, Clause 4.3.3, or Pipeline Regulation, Section 13.

L b. Type and grade differ from that stated on the licence but meet the pressure design of *CSA Standard Z662*, Clause 4.3.3, or Pipeline Regulation, Section 13.

7. Joint type

L a. Joint type is different from that stated on licence but allowed by *CSA Standard Z662* and *Guide 56*, Table 3.7.

H b. Joint type is different from that stated on licence and is not allowed by *CSA Standard Z662*.

H c. Threaded steel is used and buried below ground.

L 8. Internal coating is not as approved.

L 9. From or To location is different from that stated on licence.

L 10. From or To facilities code is different from that stated on licence.

L 11. Length of pipeline/route: Route is different from that stated on licence.

H 12. Environment code is different from that stated on licence.

13. MOP

L a. MOP is greater than that stated on licence but does not exceed the manufacturer's rating of the pipe, valves, flanges, or fittings or the limitations for sour natural gas as applicable.

H b. MOP is greater than that stated on licence and exceeds the manufacturer's rating of the pipe, valves, flanges, or fittings and connecting pipelines**.**

Construction

H 14. There is no approval to construct.

L 15. No construction notice is given to appropriate EUB Field Centre.

H 16. Conditions stated on licence are not met.

H 17. Valves, fittings, or flanges do not meet the requirements of the licence for the pipeline.

H 18. Road crossings are unsatisfactory.

H 19. Railway crossings are unsatisfactory.

H 20. Depth of cover is unsatisfactory.

H 21. Ditch preparation is unsatisfactory.

H 22. Joining/radiograph is unsatisfactory.

H 23. Bored crossings are unsatisfactory.

H 24. Pipe coating/handling conditions are unsatisfactory.

H 25. Backfill procedures are unsatisfactory.

H 26. Lease piping is unsatisfactory.

H 27. Safety precautions are unsatisfactory.

Ground Disturbance

H 28. The status of crossing agreements is unsatisfactory.

H 29. a. Marking of existing pipelines inside a controlled area is unsatisfactory.

H b. Total disregard for the requirements for marking of pipelines inside a controlled area.

H 30. a. Hand excavation: Mechanical excavation takes place within 5 m of existing pipeline prior to hand exposure.

H b. Total disregard for the hand excavation requirements.

H 31. Machine working within 60 cm without authorization from the owner of the existing crossing.

H 32. Notification to the owner of the existing pipeline prior to ground disturbance was unsatisfactory.

H 33. Notification to the owner of the existing pipeline prior to backfill was unsatisfactory.

Pressure Testing

L 34. No test notice is given to the appropriate EUB Field Centre.

H 35. Test medium/disposal unsatisfactory.

H 36. Test piping unsatisfactory.

H 37. Not tested under operating conditions.

H 38. Safety precautions unsatisfactory.

L 39. Pressure test recorded unsatisfactory.

L 40. Test pressure not between 25 and 90 per cent of the pressure recorder range.

H 41. Test pressure/duration does not conform to requirements.

Discontinued Pipeline

L 42. Not physically isolated/disconnected.

H 43. Not left in safe condition.

L 44. Corrosion control unsatisfactory.

Abandoned Pipeline

H 45. Not physically isolated/disconnected.

H 46. Not cleaned/purged and left in a safe condition.

L 47. Not plugged/capped.

Operations Review

L 48. a. Operations and maintenance procedures manual incomplete.

H b. No operations and maintenance procedures manual, or not followed.

H 49. a. Emergency procedures manual unsatisfactory.

H b. No approved site-specific emergency response plan (ERP) where required.

H c. Safety equipment specified in ERP not installed.

H d. Copy of ERP not readily available.

H e. ERP manual not updated yearly, and exercises not held or details not documented.

H f. Operator on-site representative not familiar with ERP.

L g. Operator not communicating with residents in emergency planning zone (EPZ).

L 50. Pressure test data records unsatisfactory.

H 51. a. Internal corrosion control—no records in corrosive environment.

L b. Internal corrosion control—no records in noncorrosive environment.

H c. Internal corrosion control—no monitoring and mitigation in corrosive environment.

H 52. a. External corrosion control/cathodic surveys—no records of survey results.

H b. Cathodic protection system—not operational or not installed.

L 53. Failure/repair records unsatisfactory.

H 54. Failure to notify appropriate EUB Field Centre.

H 55. No crossing approval in place.

L 56. Crossing inspection record unsatisfactory.

H 57. Leak detection unsatisfactory.

L 58. a. Pipe has been discontinued or abandoned but is still shown as operating on EUB records.

H b. Pipe is operating but is shown as discontinued or abandoned on EUB records.

L 59. a. Pipeline sign missing or defaced on one side of crossing.

H b. Pipeline sign missing or defaced on both sides of a crossing.

L 60. Aboveground facility identification unsatisfactory.

L 61. Compressor/oil pump station identification unsatisfactory.

H 62. Facility exceeding permissible sound levels.

L 63. a. Right-of-way maintenance and patrols not being performed and/or documented.

H b. Right-of-way maintenance and patrols not being performed and/or documented in Class 2, 3, or 4 area.

H 64. a. Pressure control devices or pressure relief device installations unsatisfactory (i.e., not installed where required or does not function).

H b. Required function tests not conducted or recorded.

L 65. Surface pipeline unsatisfactory.

66. *Guide 55* Storage Requirements (references are to *Guide 55* sections)

a. General storage practices (Section 3)

L i) Materials not consumed within two years.

L ii) Oilfield wastes/empty barrels stored more than one year.

H iii) All temporary single-walled aboveground tanks not diked (unless operation qualifies for it to be optional).

L iv) Temporary tank (not diked) not emptied or removed from site within 72 hours of completing the operation (drilling, completions, testing, or servicing operations).

H v) Contaminated material stored directly on the ground.

b. Siting of storage areas/facilities (Section 3.6)

L i) Not readily accessible for fire fighting and other emergency procedures.

L ii) Located on a floodplain.

L iii) Located within 100 m of normal high-water mark of a body of water, permanent stream, or water well used for domestic purposes.

c. Aboveground storage tank(s) with an internal volume less than 5 m^3 (Section 5.1)

L i) Not externally coated or made from weather and corrosion-resistant material.

d. Aboveground storage tank(s) with internal volume equal to or greater than 5 m^3 (Section 5.3)

L i) Steel tank(s) not externally coated.

L ii) Spill control device(s) not installed/inadequate.

L iii) No measures in place to prevent overfilling of tanks.

H iv) No tank dike where required.

L v) Liner not installed where required/insufficient liner.

L vi) Tank loading/unloading areas not designed to contain spills or leaks.

L vii) Tank dike(s) deteriorating, developing leaks, or unable to withstand hydrostatic head.

L viii) Insufficient tank dike capacity.

L ix) Tank dike(s) contain openings (e.g., open dike drains).

L x) Impervious liner does not cover the dike and the area within the dike not keyed into dike walls.

L xi) Aboveground tank not tested at the required five-year frequency; operator cannot demonstrate tank integrity.

L xii) Inadequate leak detection methods.

L xiii) Indoor aboveground storage tanks not surrounded by containment device and/or drain and collection tank with sufficient capacity.

e. Double-walled tanks with internal volume >5 m^3 (Section 5.33)

L i) No measures in place to prevent overfilling of tank(s) (alarms/automatic shutoffs).

L ii) Spill control device(s) not installed/inadequate.

L iii) No system to monitor interstitial space.

L iv) No barriers to protect tank from vehicular damage.

L v) Automatic shutdown system not checked on a monthly basis.

f. Underground storage tank(s) including associated piping (Section 6.0)

H i) No leak detection and secondary containment where required.

H ii) Underground storage tank(s) not double walled (tanks installed after October 31, 2001).

H iii) Newly installed tank(s) and associated piping not tested prior to service.

L iv) Steel tank(s) not cathodically protected or externally coated.

L v) Tank loading/unloading areas not designed to contain spills or leaks.

L vi) Spill control devices not installed/inadequate.

L vii) Tank breathing vents not designed to prevent fluid overflow.

L viii) No measures in place to prevent overfilling of tanks.

L ix) Underground tank(s) not tested at the required three-year frequency; operator cannot demonstrate tank integrity.

g. Storage containers with combined volume >1 m^3 on site (Section 7)

L i) Insufficient or no secondary containment (dikes, curbs, and collection trays).

L ii) No weather protection where required.

h. Bulk pads for the storage of solid materials (Section 9)

L i) Using concrete as primary containment where there is potential for stored materials to leach (bulk pads constructed after October 31, 2001).

L ii) Not constructed of compacted clay, synthetic liner, concrete, or asphalt.

L iii) No continuous curb on three sides and/or curb height not minimum 15 cm.

H iv) No leachate collection or leak detection system where required.

i. Inspection, monitoring, and record keeping (Section 10)

L i) Inventory records for last two years not available.

L ii) Records of inspection and corrosion monitoring programs not available.

L iii) Other records not available where required.

L iv) Applicable approvals, licences, or permits not on site or at field/plant offices.

j. Withdrawal of storage tanks from service (Section 12)

L i) Aboveground/underground tanks out of service do not meet the requirements.

Incident Cause

67. Failure/Hit

Consequences for Failure Mechanism

CD CONSTRUCTION DAMAGE

Examples of construction failures include, but are not limited to,

- damage to coating or pipe caused during handling
- bending
- improper installation of river/swamp weights
- improper installation of shrink wraparound sleeves
- poorly taped joint or holiday (jeep)
- damaged/disbonded coating causing shielding of cathodic protection
- improper ditch preparation causing stress failure
- settlement at risers or supports
- improper joint alignment
- poor cleaning and prepping of joints prior to welding or joining

Company representatives are responsible to ensure proper installation during construction to eliminate the above failure mechanisms. Where damage is found, the following will apply:

L a. Poor construction practices resulting in failure after one year's service/operation.

H b. Poor construction practices resulting in failure within one year's service/operation.

H c. Total disregard for CSA requirements and EUB acts and regulations.

MD MECHANICAL DAMAGE

H Includes dents, scrapes, and gouges to pipe body that were not repaired or replaced at time of contact; the system has been allowed into service and failed due to stress or corrosion.

JF MECHANICAL JOINT FAILURE

L Includes gasket, screwed couplings, "O" ring leakage, mechanical interference joints, bell, and spigot overinsertion, damaging internal coating.

CW CORROSION AT GIRTH OR FILLET WELD

Record as either corrosion external (CX) or corrosion internal (CI) (see below).

CX CORROSION EXTERNAL

H a. Cathodic potential is less than nominal –0.85 volts on an operating or discontinued system.

H b. Cathodic protection not installed within one year of service/operation.

L c. Failure to follow the investigative procedures detailed in Corrosion Guide, Section 1.3 (Appendix 2).

H d. Failure to follow the investigative procedures detailed in Corrosion Guide, Sections 2 and 4 (Appendix 2).

CI CORROSION INTERNAL

H a. There is **no** documented monitoring or mitigation program in place and/or company is not following program.

H b. There is **no** monitoring or mitigation program in place for pipelines with major potential public and environmental consequences, as referenced in Appendix 2, Section 4.

H c. Failure to follow the investigative procedures detailed in Corrosion Guide, Sections 2, 3, and 4 (Appendix 2).

L d. Failure to follow the investigation procedures detailed in Corrosion Guide, Sections 1.1, 1.2, and 3 (Appendix 2).

DO DAMAGE BY OTHERS

X a. All ground disturbance requirements were complied with and no records, survey plans, or caveats indicated lines existed.

H b. Proper procedures were not followed.

H c. Complete disregard for the acts and regulations.

EM EARTH MOVEMENT—includes river changes, frost heaves, and slope movement

X a. Right-of-way surveillance was conducted and documented and action was taken.

H b. Right-of-way surveillance was conducted and documented but no action was taken.

H c. **No** right-of-way surveillance was conducted.

GW GIRTH WELD FAILURE—includes metal failure in the heat-affected zone of weld or weld imperfections; **not corrosion related**

X a. Mandatory nondestructive inspection requirements were followed.

H b. Mandatory nondestructive inspections requirements were **not** followed.

IF INSTALLATION FAILURE—failures at a compressor station, pumping station, meter station, etc., that are all part of pipeline surface installation

X a. Compressors and pump units are designed for safe and efficient operation of the units throughout the range of operating conditions with emergency shutdown systems.

H b. Designed for full range of operating conditions, but emergency shutdown and safety protection devices do not meet requirements.

H c. **Not** designed for full range of operating conditions.

MJ MISCELLANEOUS JOINT FAILURE—includes plastic butt fusion, socket fusion, plastic butt and fibreglass threaded or bonded joining, welding or explosion welding of aluminum, mechanical interference fit, or thermal joining

X a. Proper techniques have been used during construction and operation.

H b. Manufacturer's techniques and specifications not followed.

MS MISCELLANEOUS—includes erosion from external jetting action, vandalism, lightning strikes, flooding from rivers

X No enforcement action required—acts outside of operator control.

OE OPERATOR ERROR

H Operating and maintenance procedures manual not followed.

WF OTHER WELD FAILURE—includes weldolet branch connections

L a. Caused by preventable external forces (e.g., wildlife rubbing against riser on line pipe).

H b. Proper installation procedures were not used or followed.

OP OVERPRESSURE FAILURE—includes frozen lines, waxed-off lines, pig stuck in line, hydrate plugs, switch failure, thermal overpressure

H Inappropriate construction or design, or documented operating procedures not followed.

PF PIPE FAILURE—includes pipe body failures, stress corrosion cracking, hydrogen-induced cracking, brittle cracks, running cracks, failure of plastic pipes, failure due to fatigue and lamination separations (metallurgical report must follow)

X a. No enforcement action required if cause is a manufacturing defect and the operator was not aware of potential indicators (as listed above) prior to failure.

H b. Operator is aware of pipe body issues but has not implemented mitigative measures.

SR **SEAM RUPTURE—**includes those caused by electric resistance welding (ERW) mill defects, but not failures due to overpressurization or corrosion

X a. No enforcement action required if cause of failure is a manufacturing defect that the operator was not aware of.

H b. The operator is aware that the line has integrity issues but has not implemented mitigative measures.

VF **VALVE OR FITTING FAILURE—**includes gasket blowouts, pig trap failures

X a. No enforcement action required if manufacturing flaw not detected.

H b. Pressures do not comply with manufacturer's rating, or maintenance and testing frequency are not followed.

UN **UNKNOWN—**lines that fail beneath creeks, roads, or traverse slopes that cannot be readily exposed and are abandoned in place

If the line has a history of previous corrosion failures, use the same mechanism code for this failure as the last. All lines must be cleaned and purged if they are to be abandoned in place. This may require installation of a sleeve to prevent further spillage while product is being displaced. Where a sleeve can be installed, the failure cause must be documented with the EUB.

X No enforcement action required.

68. Spill

H a. Release reporting (Pipeline Act 36(1); *IL 98-1*)—Operator is aware of a reportable release but neglects to report it. The EUB may discover the spill during an inspection, receive a report from a third party, or receive a complaint.

b. Release detail accuracy

L i) Spill reported as contained on lease when it is off lease.

L ii) Actual affected area significantly different from or larger than reported.

L iii) Actual volume of release significantly larger than reported.

H iv) Operator fails to report that spill has entered water.

H v) Operator advises that spill has been cleaned up when it has not. Cleanup refers to all free fluids being removed.

L vi) The reported location of spill is incorrect.

c. Control and containment (Pipeline Regulation 54)

H i) Operator does not take immediate steps to shut off source of liquid release (i.e., continues to produce well with leak while awaiting equipment and/or repairs).

H ii) Unaddressed spill into water, operator aware, no action is being taken.

H iii) Operator does not take steps to contain spill as soon as possible and prevent spill from spreading (e.g., berms, dykes, booms if on water).

H d. Recovery and cleanup—Spill not adequately cleaned up. (Free fluids still remain.)

e. Waste disposal

H i) Spill wastes taken to facility not authorized to accept/handle.

H ii) A one-time treatment site is not limited to a single application of waste, as per *Guide 58,* Section 16.2.

H iii) Inappropriate material put into land treatment site (i.e., salt contaminated).

H iv) Spill material moved off site for land treatment without meeting conditions in *IL 98-2*.

H v) Spill material (waste) not properly stored.

f. Area security

H i) Area is unsafe and steps not taken to restrict public access.

L ii) Steps not taken to restrict animal access.

The above could include fencing, barricades, signage, manning of site, etc.

H g. Landowner notification—Release has affected off-lease area and landowner/resident not contacted.

Other (Y/N)

69. Are *Guide 58* requirements met?

70. Is the facility being suspended?

71. Is a letter to the licensee required because the overall inspection result is “H”?

72. Has there been a records review of licensee compliance?

Appendix 2

EUB Pipeline Inspectors’ Guide to Corrosion Failure Procedures

Appendix 2—Contents

Overview

These guidelines were developed by the EUB in consultation with industry and pipeline corrosion specialists to standardize the EUB and industry approach to dealing with corrosion-related failures by expanding upon the existing Pipeline Act and Regulation and CSA standards. The aim is to enhance pipeline integrity and reduce the frequency of pipeline failures in Alberta. The procedures detailed here are presented in a flowchart in Section 7.

The following definitions explain terms as used in this appendix.

Dry sweet gas—for the purposes **of this guide only**, dry sweet gas contains **no** H_2S and its water dew point is at all times below the minimum pipeline system operating temperature (see *CSA Z662-99*, Clause 9.4.1.1, definition).

Engineering assessment—typically includes an analysis of the design parameters, materials, construction techniques, operating history, and maintenance done regarding a pipeline for the purpose of establishing whether the pipeline is fit for intended service. For further clarification, see Clause 10.11.6 of *CSA Z662-99*. Engineering assessments that involve engineering principles must be reviewed by the EUB Pipeline Section of the Operations Group.

Integrity and integrity assessment—Integrity is the expectation that a pipeline is not leaking and that it is safe to resume operation in a defined service for a defined period of time. Long-term integrity is the expectation that the pipeline is not leaking and that it is safe to resume operation for an indefinite period of time in accordance with defined operating and maintenance criteria. An integrity assessment considers the existing condition of the pipeline and the suitability of the corrosion control plan, operating characteristics, and maintenance programs.

Pipeline Section—The EUB Operation's Group Pipeline Section is the EUB pipeline inspectors' contact for EUB pipeline technical support. The Pipeline Section can be reached at (403) 297-8432, 297-8148, 297-3367, or 297-8967.

Pipeline system—any line or lines licensed for the same substance and associated with one facility.

Repeat failure—any failure that results from the same or similar cause as a previous failure on either the same line or on another line within the same pipeline system.

Sour natural gas—as defined and used in EUB *Guide 56*, gas containing more than 10 mol/kmol H_2S.

1 First Failure

1.1 Internal Corrosion Failures—All Products*

1.1.1 Visual examination of failures

Unless an in situ repair will be completed, the failed pipe must be removed for visual examination. For large-diameter pipe, it may not be feasible or necessary to remove the failure if a repair sleeve is used. The minimum length of pipe to be replaced is specified in *CSA Z662-99*, Clause 10.8.5.3. If corrosion is apparent, an entire joint should be removed, if possible, so it may be examined for severe corrosion. In certain locations it may not be possible, feasible, or necessary to remove full joints, such as at water or road crossings or on slopes. If an in situ repair is completed, the repair will be considered as temporary until the requirements set out here in Section 1.1 are met.

1.1.2 Lab analysis

A sample containing the failure must be cut out and sent for lab analysis to determine failure cause and/or mechanism, unless the cause and mechanism are obvious or already known. Any pipe structural failure (e.g., buckling, collapse, rupture, or seam failure) should be sent for metallurgical or mechanical analysis. The failed section should not be disturbed (e.g., cleaned, torch cut, or split) and should be taped off or sealed on the ends.

1.1.3 Visual examination of adjacent pipe

The remainder of the removed section should be split, cleaned, and inspected for further corrosion.

1.1.4 Replacement

Any replaced section must be replaced with pipe having the same grade and wall thickness or, if not available, grade and wall thickness sufficient to ensure that equal or higher pressure and stress capability are maintained.

1.1.5 Localized corrosion

If the corrosion appears to be localized (restricted to a single area), acceptable options for repair would be to either replace the section and follow with a pressure test or replace the section using pretested pipe followed by radiographic, ultrasonic or other nondestructive weld inspection. A documented corrosion plan must be prepared as outlined in 1.1.8 below.

1.1.6 Nonlocalized corrosion

If the corrosion is not localized (restricted to a single area) or there is reason to suspect that the corrosion could be inherent to other parts of the pipeline, then further action is required. A pressure test or internal inspection must be conducted or an engineering

* For additional requirements for sour natural gas and HVP pipelines, see Sections 1.2 and 4; for pipelines having higher failure consequence, see Section 4; for repeat failures, see Section 2.

assessment done. A documented corrosion plan must be prepared as outlined in 1.1.8 below.

1.1.7 Sleeve repairs

If cutout is not feasible, a temporary repair sleeve may be appropriate. For a leaking internal corrosion failure, a repair would be done by using a pressure containment sleeve. The welds on the sleeve must be inspected without causing damage. As the pipeline is being pressured up for return to service, the sleeve must be visually inspected for any leaking defects (e.g., using a soap test). See *CSA Z662-99*, Clause 10.8.5.4 and Table 10.1, for clarification on sleeve use.

1.1.8 Corrosion mitigation plan

If a failure indicates a corrosive condition, the operator must have a documented plan to prevent further corrosion failures. This plan must consider other lines within the same pipeline system and include details of the mitigative measures to be adopted. The Pipeline Regulation, Sections 52 and 53, requires the operator to maintain records of any corrosion maintenance activities for at least six years. Typical mitigative and monitoring measures for internal corrosion could include combinations of the following: lab analysis to determine failure cause, pipeline cleaning by pigging or chemicals, inhibition (continuous and/or batch), maintenance pigging, electronic monitoring devices, corrosion coupons, fluids analysis, and flow modelling. If operator expertise is insufficient, the operator should enlist expert third-party assistance.

1.1.9 Evaluation of corrosion mitigation plan

Details of the plan must be discussed with the operator to ensure that the plan is reasonable for that pipeline or pipeline system and the existing operating conditions.

1.1.10 Coating inspection

The exposed pipeline must be inspected visually for external coating condition. Defects such as disbondment, taped repairs, improperly applied shrink sleeves, or ripples resulting from areas of soil shear may exist. If external corrosion is found, the coating must be removed and the pipe examined. Inspection for stress corrosion cracking (SCC) using wet magnetic particle inspection should also be conducted in areas where external corrosion has been found unless the company has sufficient documentation to show that SCC is unlikely.

1.1.11 Stress corrosion cracking (SCC) inspection

Even though the pipeline may not exhibit external corrosion, if it meets the criteria for high probability of SCC, the operator must conduct an examination for SCC. The exposed pipeline segment must be examined and the operator must consider assessment of other parts of the system as well. If SCC has been confirmed, the EUB Pipeline Section, Operations Group, must be notified for possible further follow-up. Excavation and investigation of exposed pipe is an acceptable method to conduct evaluations for SCC.

1.1.12 Return to service (satisfactory pipeline integrity)

In cases where pipeline integrity has been confirmed, the pipeline can return to service while the documented corrosion plan is being developed.

1.1.13 Temporary service (long-term integrity is uncertain)

If long-term pipeline integrity is uncertain but it is desirable to allow the pipeline to return to temporary operation based on significant need, the following measures must be considered to minimize any risks of failure and to minimize potential spill volume: pressure reduction, line patrol (aerial or using gas leak detection equipment but being aware of sour natural gas hazards), pressure monitoring, and additional metering.

Before allowing any return to service, the following matters must also be considered: the severity of the exhibited corrosion, the potential likelihood of failure, population density, and possible environmental and public risk as a consequence of failure.

The operator must provide within 30 days a written plan of further action for EUB review. Normal pipeline operations may be resumed only after further work is done that confirms or re-establishes long-term integrity. Further work could include an engineering assessment. The need to allow such pipelines to return to temporary service must be discussed with the local EUB Field Centre Team Leader (FCTL) or the EUB Operations Leader prior to approval.

1.1.14 Audit

Selected operators will be audited for corrosion prevention activities, the presence of a documented corrosion monitoring and mitigation plan, and their compliance with the plan within 12 months of the failure.

1.1.15 Discontinuation/abandonment

If a pipeline is discontinued or abandoned, the company must notify the EUB, as required in EUB *Guide 56*, within 90 days of completing discontinuation or abandonment operations.

1.2 Internal Corrosion Failures——Additional Requirements for Level 1 Sour Natural Gas (as per *ID 81-3*) and CSA Class 1 HVP Pipelines*

1.2.1 Temporary service

Temporary operation without proof of long-term integrity will not be allowed.

1.2.2 Confirmation of integrity

Proof of long-term integrity can be achieved through one or more of the following:

- internal electromagnetic or ultrasonic in-line inspection, followed by necessary repairs
- replacement of the line

* For additional requirements for Level 2, 3, or 4 sour natural pipelines and Class 2, 3, or 4 HVP pipelines, see Section 4.

- installation of a liner, as per the procedures of *CSA Z662-99*
- flow modelling analysis, followed by verification digs, necessary repairs, and implementation of an appropriate corrosion prevention program
- an engineering assessment of the pipeline integrity, followed by any necessary repairs
- additional corrosion control program modifications as necessary; note that at least one of the prior items must also be implemented

A pressure test alone will not be considered as adequate proof of long-term integrity. Note that sour natural gas lines require pressure testing to 1.4 x MOP.

Random cutouts, ultrasonic inspection, and shadow shots are not adequate proof of integrity.

1.3 External Corrosion Failures—All Products*

For additional requirements for Level 2, 3, or 4 sour natural gas pipelines and Class 2, 3, or 4 HVP pipelines, are given in Section 4.

1.3.1 Visual examination of coating and failure

The exposed pipeline section must be examined visually for external coating condition. Defects such as disbondment, taped repairs, improperly applied shrink sleeves, or ripples resulting from areas of soil shear may exist. If external corrosion is found, the coating must be removed and the pipe examined. Inspection for SCC using wet magnetic particle inspection should be conducted in areas where external corrosion has been found unless the company has sufficient documentation to show that SCC is unlikely. If the failure appears to be the result of third-party damage, it may be unnecessary to conduct SCC examination.

1.3.2 Stress corrosion cracking (SCC) inspection

Even though the pipeline may not exhibit external corrosion, if it fits the criteria for high probability of SCC, the operator must conduct an examination for SCC. The exposed pipeline segment must be examined and the operator must consider assessment of other parts of the system as well. If SCC has been confirmed, the Pipeline Section should be notified for possible further follow-up. Excavation and investigation of the exposed pipe is an acceptable method to conduct evaluations for SCC colonies.

1.3.3 Replacement

Any replaced section must be replaced with pipe having the same grade and wall thickness or, if not available, grade and wall thickness sufficient to ensure that equal or higher pressure and stress capability are maintained.

1.3.4 Localized corrosion

If the corrosion appears to be localized (restricted to a single area), acceptable options for repair would be to either replace the section and follow with a pressure test or replace the

* For additional requirements for sour natural gas and HVP pipelines, see Sections 1.2 and 4; for pipelines having higher failure consequence, see Section 4; for repeat failures, see Section 2.

section using pretested pipe followed by radiographic, ultrasonic, or other nondestructive weld inspection. A documented corrosion plan must be prepared as outlined in 1.3.7 below.

1.3.5 Nonlocalized corrosion

If corrosion is not localized (restricted to a single area) or there is reason to suspect that the corrosion could be inherent to other parts of the pipeline, further action is required. A pressure test or internal inspection must be conducted or an engineering assessment done. A documented corrosion plan must be prepared as outlined in 1.3.7 below.

1.3.6 Sleeve repair

If cutout is not feasible, a repair sleeve may be appropriate. For a leaking external corrosion failure area, a repair would be done by using a pressure containment sleeve. If a pressure containment sleeve is used on nonleaking corrosion, the pipe must be tapped to pressurize the annulus between the pipe and the sleeve *CSA Z662-99*, Clause 10.8.5.4.2(g)). The welds on the sleeve must be inspected without causing damage. As the pipeline is being pressured up for return to service, the sleeve must be visually inspected for any leaking defects. A reinforcement repair sleeve would be used on a nonleaking external corrosion area. See *CSA Z662-99*, Clause 10.8.5.4 and Table 10.1, for clarification on sleeve use.

1.3.7 Corrosion mitigation plan

If a failure indicates a corrosive condition, the operator must have a documented plan to prevent further corrosion failures. The plan must consider other lines within the same pipeline system and include details of the mitigative measures to be adopted. The Pipeline Regulation, Sections 52 and 53, requires the operator to maintain records of any corrosion maintenance activities for at least six years. Typical mitigative and monitoring measures for external corrosion could include combinations of the following: evaluation of cathodic protection system, close interval survey, C scan, coating evaluation, and SCC evaluation. If operator expertise is insufficient, the operator should enlist expert third-party assistance.

1.3.8 Evaluation of corrosion mitigation plan

Details of the plan must be discussed with the operator to ensure that the plan is reasonable for that pipeline or pipeline system and the existing operating conditions.

1.3.9 Return to service (satisfactory pipeline integrity)

In cases where pipeline integrity has been confirmed, the pipeline can return to service while the documented corrosion plan is being developed.

1.3.10 Temporary service (long-term integrity is uncertain)

If long-term pipeline integrity is uncertain but it is desirable to allow the pipeline to return to temporary operation based on significant need, the following measures must be considered to minimize any risks of failure and to minimize potential spill volume: pressure reduction, line patrol (aerial or using gas leak detection equipment but being aware of sour natural gas hazards), pressure monitoring, and additional metering.

Before allowing any return to service, the following matters must also be considered: the severity of the exhibited corrosion, the potential likelihood of failure, population density, and possible environmental and public risk as a consequence of failure.

The operator must provide within 30 days a written plan of further action for EUB review. Normal pipeline operations may be resumed only after further work is done that confirms or re-establishes long-term integrity. Further work could include an engineering assessment. The need to allow such pipelines to return to temporary service must be discussed with the local EUB Field Centre Team Leader (FCTL) or the EUB Operations Leader prior to approval.

1.3.11 Third-party damage/construction damage

If failure is a result of third-party or construction damage and the operator's assessment indicates that other corrosion is not a problem, then a repair using pretested pipe followed by radiographic, ultrasonic, or other nondestructive testing of the weld is sufficient. If either construction damage or mechanical damage initiated failure, the cause must be recorded as such.

1.3.12 Audit

Selected operators will be audited for corrosion prevention activities, the presence of a documented corrosion monitoring and mitigation plan, and their compliance with the plan within 12 months of the failure.

1.3.13 Discontinuation/abandonment

If a pipeline is discontinued or abandoned, the company must notify the EUB, as required in EUB *Guide 56*, within 90 days of completing discontinuation or abandonment operations.

2 Repeat Failures

A repeat failure could be either on the same line or on another line within the same pipeline system (see definitions in Overview). Note that the requirements below are to be used in conjunction with those found in Sections 1.1 and 1.3.

2.1 Internal or External Corrosion Failures—All Products

2.1.1 Insufficient due diligence

If an operator experiencing a repeat failure is not following its pipeline operations and maintenance manual and a documented corrosion mitigation plan or does not have a suitable manual or plan in place, then the pipeline cannot be returned to service until these issues are resolved to the satisfaction of the EUB.

2.1.2 Failures on dry sweet gas pipelines

For repeat failures on dry sweet gas (see definition in Overview) where there is no significant environmental or public risk and the operator has been following an acceptable operations and maintenance manual and documented corrosion mitigation plan, further written integrity assessments will not routinely be required.

2.1.3 Return to service—dry sweet gas pipelines

If a written integrity assessment and modified corrosion control plan are required, they must be satisfactory to the EUB inspector. Once the integrity assessment is satisfactory or it is determined that no further integrity assessment is required, dry sweet gas pipelines may be returned to service in combination with an acceptable leak monitoring program, such as visual inspections or flame ionization inspections.

2.1.4 Failures other than dry sweet gas pipelines

For repeat failures on other than dry sweet gas (see definition in Overview) pipelines, the failure indicates that the previous corrosion control program may not be adequate. Therefore, the company must provide a complete written integrity assessment of the subject pipeline(s) and a thorough plan to prevent any further failures. This may require an engineering assessment or third-party consultation, which must consider the pipeline condition, extent of corrosion, product carried, population density, environmental and public risk, and proposed mitigative and operational changes necessary to prevent further failures.

2.1.5 Return to service—other than dry sweet gas pipelines

Details of the written integrity assessment and modified corrosion control plan must be satisfactory to the EUB inspector, and the engineering assessments must be satisfactory to the EUB Pipeline Section before the pipeline may be returned to service.

2.1.6 Audit

Selected operators will be audited for corrosion prevention activities, the presence of an acceptable operations and maintenance manual and documented corrosion monitoring and mitigation plan, and for compliance with such documents within 12 months of the failure.

2.1.7 Discontinuation/abandonment

If a pipeline is discontinued or abandoned, the company must notify the EUB, as required in EUB *Guide 56*, within 90 days of completing discontinuation or abandonment operations.

3 Failures on Internally Coated Pipelines

3.1 Internal or External Corrosion Failures—All Products

3.1.1 General requirements

The same procedure as for other failures must be followed, unless failure was initiated at a joint due to improper joining procedures.

3.1.2 Joint failures

If a failure was initiated at a joint, further digs must be conducted to inspect joints using nondestructive testing methods. Failures due to improper joining procedures must be recorded as mechanical joint failure.

3.1.3 Internal coating integrity

Repairs must re-establish continuous internal coating integrity at the repaired location. If coating integrity cannot be restored, an alternative method of corrosion prevention must be implemented, such as inhibition or use of other liners.

4 Failures on Pipelines with Major Potential Public and Environmental Consequences

Pipelines with major potential failure consequences include

- any Level 2, 3, or 4 sour natural gas pipeline (as per *ID 81-3*)
- any pipeline in a *CSA Z662-99* Class 2, 3, or 4 area (except dry sweet gas)
- any pipeline 323.9 mm (12 inch) diameter or larger
- any liquids pipeline crossing water or within 100 m of a water body
- any liquids pipeline crossing parks or wetlands
- any flammable liquids pipeline within 1.5 km of villages, towns or cities

4.1 General Requirements

The same investigative technique and follow-up as used for repeat failures must be used.

4.2 Return to Service

All assessments, evaluations, and corrosion monitoring and mitigation plans must be fully completed and reviewed by EUB staff before considering recommissioning. Long-term integrity must be assured by the use of one or more of the following:

- internal electromagnetic or ultrasonic in-line inspection, followed by necessary repairs
- replacement of the line
- installation of a liner as per the procedures of *CSA Z662-99*
- a suitable alternative course of action (supported by an engineering assessment) that meets with the satisfaction of the EUB field inspectors and EUB Pipeline Section staff

A pressure test alone will not be considered as adequate proof of long-term integrity.

Note that HVP lines in *CSA Z662-99* Class 2, 3, or 4 must be tested to 1.5 x MOP and all sour natural gas lines must be tested to 1.4 x MOP.

4.3 Large-Diameter Pipelines

Any failure of a pipeline 323.9 mm (12 inch) or larger must be reported to the EUB Pipeline Section for their possible follow-up.

5 Resumption of Operation of Discontinued or Abandoned Pipelines

5.1 Assessment Procedures

The requirements of *CSA Z662-99*, Clause 10.13.2, which outline the engineering assessment procedures that are necessary, are to be followed before making application for resumption.

5.2 Application Requirement

An application for resumption (licence amendment) is submitted to the EUB following the normal *Guide 56* process and must include the required assessment information.

5.3 Technical Inquiries

Technical inquiries may be directed to the EUB Pipeline Section.

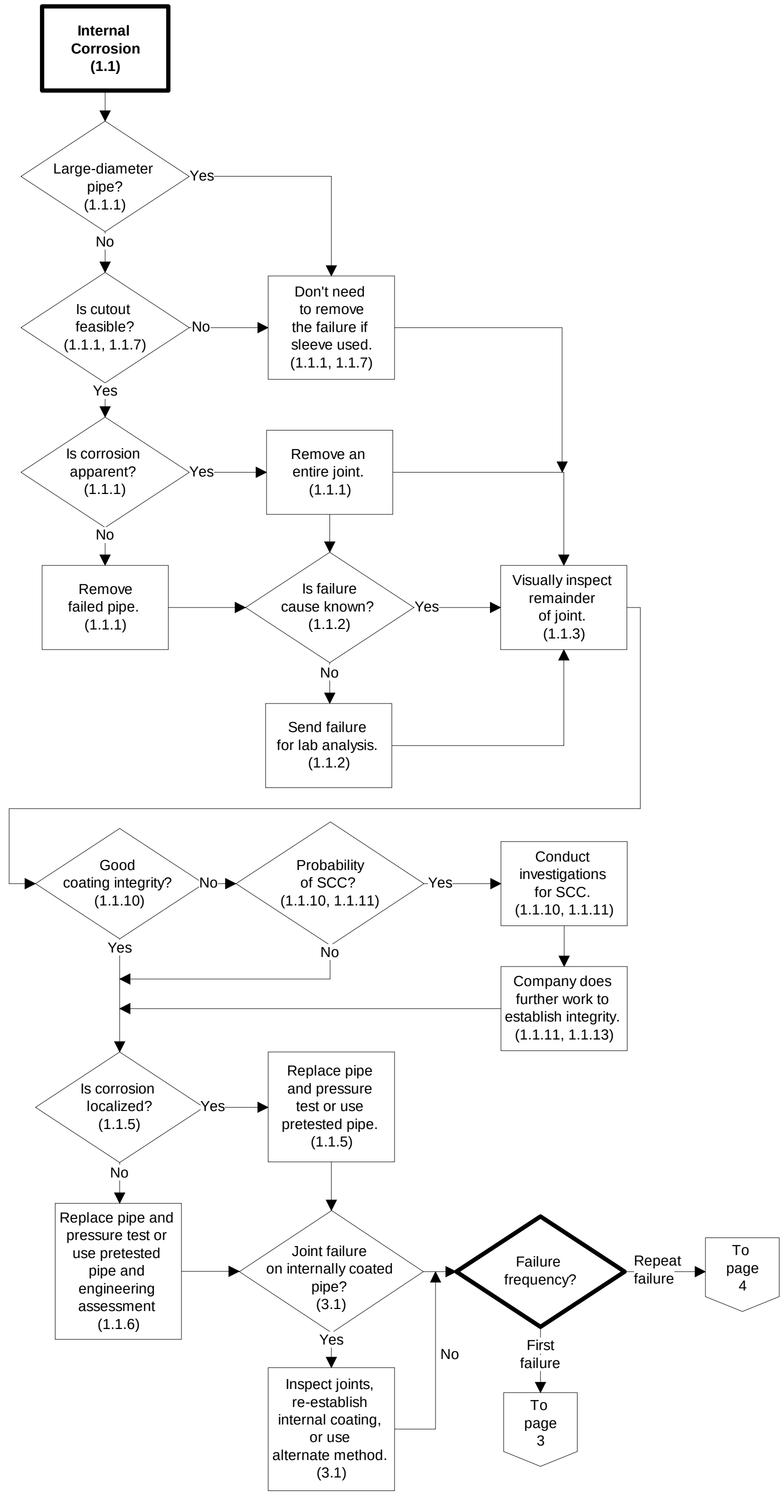
6 Enforcement

The EUB has adopted an enforcement process that includes guidelines for EUB enforcement actions when dealing with regulatory noncompliance. Companies failing to meet requirements or follow EUB direction will be subject to escalating enforcement consequences. Details of the EUB enforcement process are contained in *Directive 019: EUB Compliance Assurance—Enforcement*.

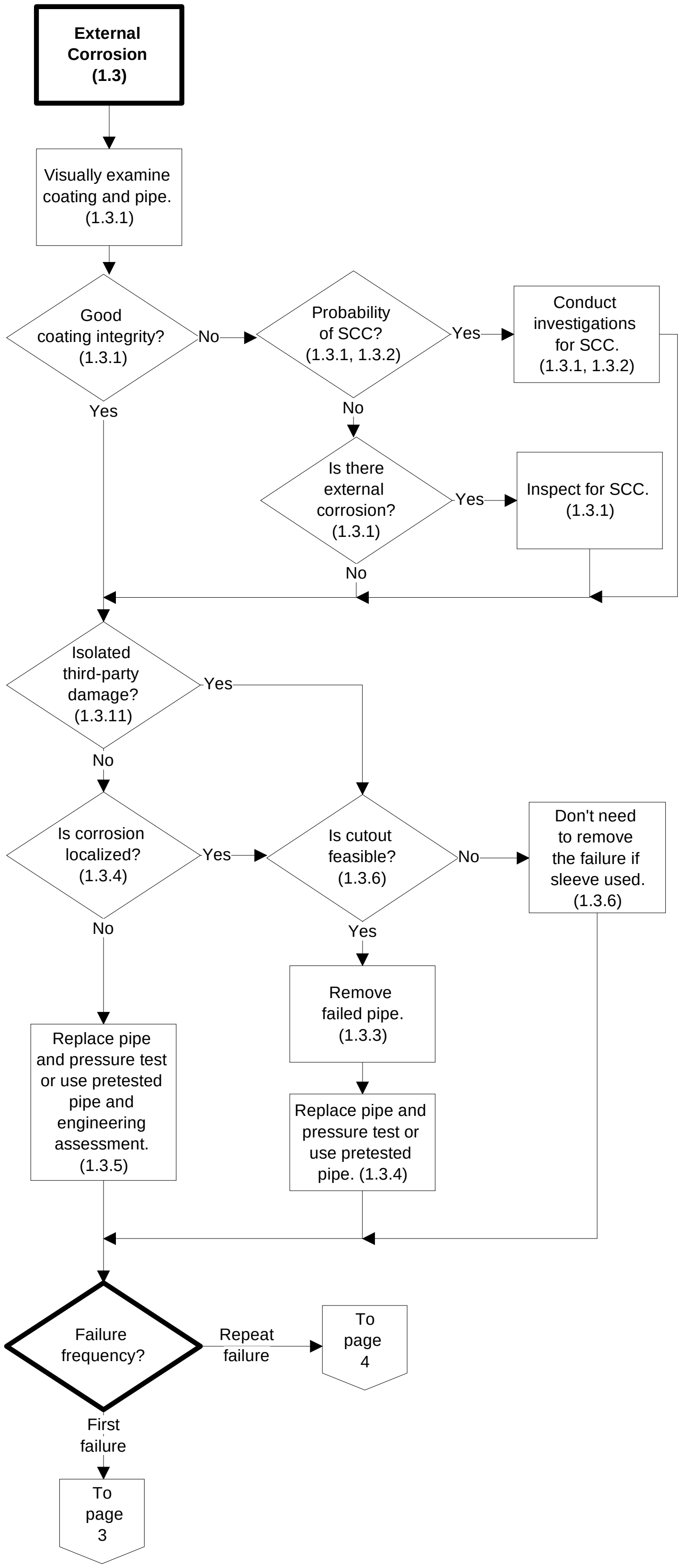
Although the procedures in this corrosion guide are not detailed in the Pipeline Act or Regulation, they are recognized as representing good practice and are written to reduce potential future failures that could result in environmental and public impacts. If a licensee does not conduct failure incident reviews and follow-up according to the general intent of this guide, the licensee will be subject to EUB-applied enforcement processes as outlined in *Directive 019*, based on the potential or actual impact on the public and environment.

7 Corrosion Failure Procedures Flowchart (page 1)

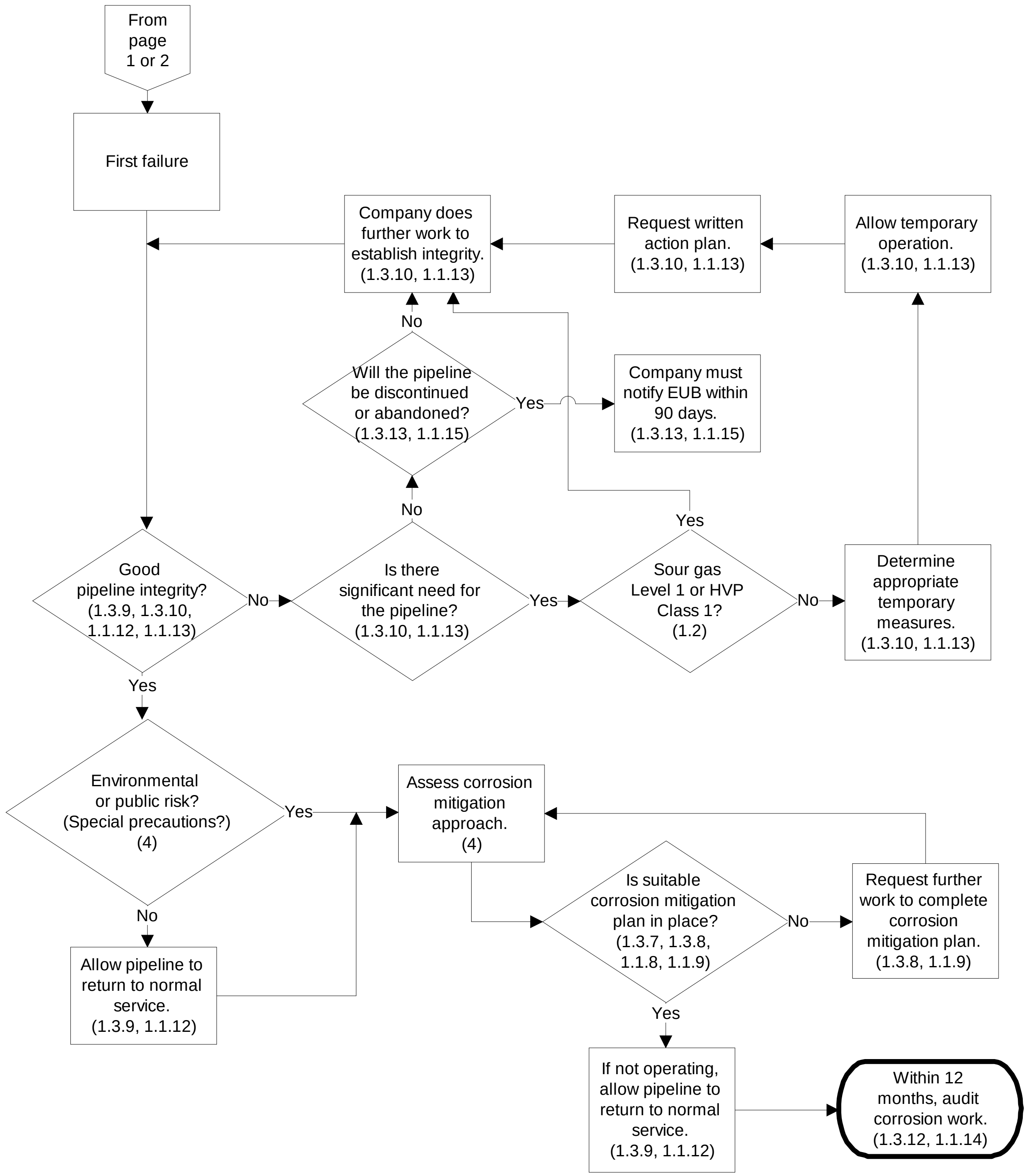
The numbers within parentheses in this four-page flowchart refer to the relevant preceding sections in the corrosion guide (Appendix 2).



Corrosion Failure Procedures Flowchart (page 2)



Corrosion Failure Procedures Flowchart (page 3)



Corrosion Failure Procedures Flowchart (page 4)