QUESTAR

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Pipeline Compliance
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Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

March 19, 2012

Re: Response to Notice of Amendment CPF 5-2011-1010M.

Dear Mr. Hoidal:

Questar Pipeline appreciates the input from the Western Region inspectors and has modified various sections of the Operations and Maintenance Manual to remediate the issues addressed by the inspectors. The majority of the amendments were made before the conclusion of the inspection. The remaining few were then modified shortly thereafter.

The following table has the numbered issue identified during the inspection corresponding to the document that was modified. Each of these documents is attached with this correspondence.

Issue	Organization
1	Standard Practice 3-90-01
2	Standard Practice 5-00-07
3	Standard Practice 3-70-01
4	Standard Practice 1-01-03
5	Standard Practice 5-00-02
6	Performance Standard Section M
7	Standard Practice 7-00-01
8	Emergency Plan Sections 6 and 8
9	Emergency Plan Section 9
10	Emergency Plan Section 5 and Standard Practice 8-18-01

1. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (8) Periodic reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedure when deficiencies are found.

The Questar O&M manual did not contain a procedure for periodic review of the work performed by operator personnel to determine the effectiveness and adequacy of the procedures. The Questar O&M manual did not describe when or how the procedures are to be reviewed, as required by §192.605(b)(8).

Questar Pipeline Modifications:
The Questar Pipeline procedure for annual review of the O&M manual as well as the periodic review of work done is found in Standard Practice 3-90-01. This standard was reviewed during the inspection. The modifications made, as recommended by the inspectors, are highlighted in red. When the procedures are to be reviewed is documented in paragraphs 3.1 and 3.2 of Standard Practice 3-90-01. How the procedures are to be reviewed is covered in sections 6 and 7 of Standard Practice 3-90-01. The inspectors recommended the review be associated with the Operator Qualification program and that the task be observed as part of the review of the procedure. This was captured in paragraph 7.3 and referenced in paragraph 2.1.

2. §192.614 Damage prevention program.
   (c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
   (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
   (*iii*) In case of blasting, any inspection must include leakage surveys.

The Questar damage prevention program did not reference blasting as a condition to trigger a leak inspection, as required by §192.614(c)(6)(ii).

Questar Pipeline Modifications:
Questar Pipeline's Standard Practice 5-00-07, paragraph 9.3 did reference performing a leak survey when blasting occurs. Questar also has a specific stress analysis standard that contains blasting calculations that was also reviewed. The recommendation by the inspectors was to reference the stress analysis standard in the damage prevention standard. This was captured in paragraph 9.2 and referenced in paragraph 2.4 of Standard Practice 5-00-07.

3. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

Questar operates a transmission line which is in a Class 3 Area for more than 50% of its length downstream from a Class 3 area. Questar's sister company, Questar Gas Company (QGC) odorizes as is required; however, Questar does not have any procedures to monitor and measure the effectiveness of the odorization. Pursuant to §192.605(b)(1), an operator must have procedures for each of the requirements of this subpart and Subpart M. Section 192.625(f) requires the operator to conduct periodic sampling to verify proper odorization. The Questar O&M manual did not have an odorization procedure describing how periodic sampling is to occur, and instead relied on its sister company to conduct periodic sampling.

Questar Pipeline Modifications:
Questar has modified section 1 of Standard Practice 3-70-01 to be applicable to both Questar Gas and Questar Pipeline; and this standard has been adopted into the Questar Pipeline O&M manual.

4. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

The Questar O&M manual did not include a section required to inspect the right-of-way, or how the right-of-way is to be inspected. Questar's procedures pertaining to Part 192.14 are inadequate because Questar did not clearly indicate that inspections of the right-of-way are required to be conducted.

Questar Pipeline Modifications:
Questar Pipeline modified Standard Practice 1-01-03 paragraph 7.1 and added paragraphs 7.2, 7.3, and 7.4 as recommended to account for right-of-way inspection.

5. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

All repairs made by welding in accordance with §§§ 192.713, 192.715, 192.717 must be examined. The Questar O&M Manual did not include a section that specifically describes the process of how "non-destructive" testing of repair sleeves is to occur, as required by §192.719(b).

Questar Pipeline Modifications:
Questar Pipeline had the language in other sections of Standard Practice 5-00-02, and needed to add it to Section 8. Therefore paragraph 8.6 was modified to be consistent with paragraph 7.7.

6. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

The Questar O&M manual did not provide specific examples for appropriate locations for warning sign postings, as required per §192.751(c). The procedure did not state where warning signs should be posted to minimize the danger of accidental ignition of gas.

Questar Pipeline Modifications:
Questar Pipeline enhanced the section concerning specific locations of warning signs in Performance Standard Section M, paragraph 2.4.

7. §192.605 Procedural manual for operations, maintenance, and emergencies.
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for following, if applicable, to provide safety during maintenance and operations.
   (2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

The Questar manual did not include specific language to quantify the term "prompt", when referencing monitoring of external corrosion control, §192.465(d). If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion, as required per §192.479. The Questar manual did not state how protection against corrosion is to be performed.

Questar Pipeline Modifications:
Questar Pipeline added paragraph 9.1 to Standard Practice 7-00-01 to include how protection against corrosion is to be performed. The term "prompt" was included and also quantified in paragraph 11.6 and subsequent sub-paragraphs.

8. §192.615 Emergency Plans.
   (b) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
   (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

The Questar O&M manual did not reference any emergency events that would require an immediate response from the operator, as required by §192.615(a)(1). The manual did not contain the procedures required for receiving, identifying, and classifying notices of events requiring immediate response.

Questar Pipeline Modifications:
Questar Pipelines Emergency Plan Section 8 had various System Emergencies. The plan was modified to include the specific language "Requiring an Immediate Response" as noted in paragraph 3. Modifications were also made to various sub-paragraphs of paragraph 3 to classify the emergency. In addition, modifications were made to Emergency Plan Section 6.

9. §192.615 Emergency Plans.
   (b) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
   (9) Safely restoring any service outage.

The Questar O&M manual did not contain instructions describing how service outages are to be restored after the emergency has been rendered safe. Questar's procedures are inadequate pertaining to §192.615(a)(9) because Questar did not describe how service outages are to be restored after an emergency.

Questar Pipeline Modifications:
Questar Pipeline's Emergency Plan Section 9 was modified to include the specific language "have been rendered safe" as noted in paragraph 1.2. How service outages are to be restored was described in subsequent sub-paragraphs under 1.2.

10. §192.615 Emergency Plans.
    (b) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
    (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.

The Questar O&M manual did not contain language requiring that accidents be investigated as soon as possible after the emergency.

Questar Pipeline Modifications:
Questar Pipeline modified Emergency Plan Section 5 to include specific language requiring accidents to be investigated as soon as possible after an emergency. This is noted in sub-paragraph 2.4.1 in Section 5 of the Emergency Plan. Modifications were made to section 1 of Standard Practice 8-18-01 to reflect this recommendation.

If you have any question pertaining to this letter or request any other documents please don't hesitate to contact me. In the spirit of transparency, Questar Pipeline is more than willing to provide its entire O&M manual electronically on CD.

Sincerely,

Troy Sorensen
Senior Engineer, Pipeline Compliance

Questar Standard Practice

3-90-01 ANNUAL REVIEW OF PROCEDURES MANUAL AND PERIODIC REVIEW OF WORK DONE BY COMPANY PERSONNEL

1. PURPOSE

This Standard Practice provides instructions for the annual review and update (if required) of the Procedures Manual and the periodic review of work done by Company personnel. The periodic review is to ensure that the written procedures used for normal operations and maintenance are adequate and effective.

2. REFERENCES

2.1. Company Operator Qualification Program.

3. DEFINITIONS

3.1. Annual review - at least once each calendar year at intervals not to exceed 15 months.

3.2. Periodic review – at least once each three calendar years.

3.3. Periodic Review Report – a form which documents periodic review of work done and is signed by qualified personnel and approved by supervision.

3.4. Procedures Manual – a manual of written procedures for conducting operations and maintenance activities and for emergency response.

3.5. Procedures Manual Review Report – a form which documents the annual review of the procedures manual.

3.6. Reviewer – the employee designated in the Central DOT Records System as responsible for the annual review of the Procedures Manual or the periodic review of work done by Company personnel to evaluate the effectiveness and adequacy of written procedures contained in the Procedures Manual.

4. SAFETY

Ensure appropriate personal protective equipment is worn, when reviewer is on site and in close proximity to active equipment and facilities.

5. PERSONNEL QUALIFICATIONS

Employees responsible for the annual review of the Procedures Manual and the periodic review of work done by Company personnel will be familiar with the responsibilities outlined herein.

6. ANNUAL REVIEW AND UPDATE OF PROCEDURES MANUAL

6.1. At least once each calendar year, at intervals not to exceed 15 months, the Procedures Manual will be reviewed and updated as needed.

NOTE:	*Minor changes to the Procedures Manual (i.e. editorial changes, or other non-substantive changes) will not require formal Standard Practice committee approval and can be approved by the Supervisor of Pipeline Compliance. These minor changes are designated by an alpha character following the revision number (e.g. Revision 02A).*

6.2. The Pipeline Compliance department will be responsible for the Procedures Manual annual review.

6.3. The Standard Practice committee will be responsible for approving any updates being made to the Procedures Manual during committee meetings scheduled periodically during the calendar year.

6.4. Distribution of updated material for the procedures manual will be coordinated by the Pipeline Compliance department as needed.

6.5. Annual review of Procedures Manual will be documented on the "Review of Procedures Manual" form (generated by Pipeline Compliance, Central DOT Records System).

6.6. Records from Standard Practice Committee meetings will supplement the annual procedures review documented above in paragraph 6.5.

7. PERIODIC REVIEW OF WORK DONE BY COMPANY PERSONNEL

NOTE:	*Employees responsible for the periodic review of work done by Company personnel will be designated in the Central DOT Records System.*

7.1. Employees responsible for the periodic review of work done by Company personnel will:

7.2. Determine effectiveness and adequacy of written procedures used in normal operations and maintenance activities.

7.3. Observe associated covered tasks as outlined in the DOT Operator Qualification Program during performance on the job as outlined in §192.803 Evaluation (d)(1).

7.4. Identify any deficiencies or areas for improvement in the written procedures used in normal operations and maintenance activities.

7.5. Prepare a mark-up of the written procedure with suggested deletions, additions or alternate language.

7.6. Forward completed Periodic Review Report along with mark-up of written procedure (if revisions are required) to the Central DOT file for revision by Pipeline Compliance.

8. RECORDS

Records related to the annual review of the procedures manual and the periodic review of work done by Company personnel will be maintained in the Central DOT file for a minimum of three years.

Questar Pipeline Standard Practice

5-00-07 UNDERGROUND FACILITIES DAMAGE PREVENTION PROGRAM

1. PURPOSE

This Standard Practice describes procedures to follow to prevent damage to underground facilities caused by excavation. These procedures will be followed by personnel associated with the Company underground facilities damage prevention program.

2. REFERENCES

2.1. Company DOT Operator Qualification Program.

2.2. Company Public Awareness Program.

2.3. Applicable Manufacturer's Operation and Maintenance Manuals.

2.4. Standard Practice 1-01-04, "Stress Analysis of Buried Pipes."

2.5. Standard Practice 2-17-02, "Excavating and Backfilling."

2.6. Standard Practice 2-18-01, "Marking Pipelines and Pipeline Facilities."

2.7. Standard Practice 4-85-02, "Goldak Pipe and Cable Locator Operation and Maintenance Procedure."

2.8. Standard Practice 7-35-01, "Inspecting Aboveground and Exposed Portions of Steel Pipelines and Facilities for Corrosion."

3. DEFINITIONS

3.1. Disturbance Activities - for the purpose of this Standard Practice disturbance activities shall include, but not be limited to: excavating, blasting, boring, tunneling, backfilling, driving posts or ground rods, the removal of above ground structures by either explosive or mechanical means and other earth moving operations. Refer to S. P. 2-17-02 for additional disturbance activities.

3.2. Encroachment - any activity by non-Company personnel that physically infringes upon pipeline facilities or rights-of-way.

3.3. Location Request - an application by telephone or in person through a one-call system requesting the location of utilities before excavation begins.

3.4. One-Call System - a service designed to provide the following in a geographical area (City, County, State):

3.4.1. A "one-call" convenience for excavators to notify underground facility operators of excavation activities two working days before digging.

3.4.2. The opportunity for underground facility operators to identify their facilities for excavators before excavation activities begin, thus preventing damage to underground facilities.

3.5. Right-of-Way - the right of use (easement) granted to the Company of a narrow strip of land running parallel with and inclusion of a pipeline which provides access for construction, maintenance and operation of the pipeline. Also includes undescribed rights of way (Land not tied to specific bearings and distances. Undefined widths vary based on pipeline type and state statutes). Typical IHP Distribution Undefined ROW are 16 feet width, 8' on either side of the pipeline. Distribution High Pressure (HP) ROW widths in Utah are 30', 15' on either side of pipeline. Distribution HP in Wyoming and all QPC transmission pipelines undefined ROWs are 30' in width, 15' on either side of pipeline. QST has no undefined ROW widths.

4. **SAFETY** - No specific instructions required.

5. PERSONNEL QUALIFICATIONS

5.1. Personnel responsible for performing covered task(s) outlined herein will be qualified or be directed and observed by someone who is qualified as outlined in Company DOT Operator Qualification Program.

5.2. Personnel will be familiar with the procedures and safety precautions outlined herein.

6. IDENTIFICATION AND NOTIFICATION OF STAKEHOLDER AUDIENCES

Refer to Questar's Public Awareness Program for a description of the stakeholder audiences. This program also defines the baseline messages and the frequency of delivery, and the method for delivering these messages.

7. PROCESSING LOCATION REQUESTS

7.1. When calls for location requests are received, refer caller to appropriate one-call center, this will provide documentation of request. Refer to Table 1 for appropriate one-call centers.

7.2. Questar Gas Company (QGC) uses Company and contract personnel to locate facilities.

7.3. Questar Pipeline Company (QPC) contracts location of Mainline 104. QGC locates for QPC in Rock Springs and Evanston. All other QPC facilities are located by QPC personnel.

7.4. Questar Southern Trails Pipeline Company (QST) personnel locate QST facilities.

8. LOCATING UNDERGROUND FACILITIES

8.1. Location requests will be handled in the following order:

8.1.1. Emergency - between 0-2 hours - give immediate attention and process over all other requests.

NOTE:	*Colorado requires emergency location requests to be processed within one hour.*

8.1.2. Normal - normal location requests will be completed within 48 hours. The excavator is to place a new locate request:

a. If the markings have been disturbed.

b. During a continuing project.

8.1.3. Exceptions to the 48 hour notice are:

a. Location not clearly described by street address or location.

b. Location in a remote area.

c. Location request is extensive or presents other constraints, making marking unreasonably difficult.

8.1.4. If situations described in paragraph 8.1.3 occur, have locator arrange a meeting with the excavator at proposed excavation site or mutually agreed site within the 48 hour period. Begin a new 48 hour period from arranged meeting.

8.2. Before operating pipeline locating equipment, refer to applicable Manufacturer's Operation and Maintenance Manuals for instructions on use. Contact area supervision for information regarding specific type of equipment used in your area. Refer to S.P. 4-85-02.

8.3. Ensure location requests are completed.

8.4. Use safety yellow to mark underground gas facilities.

8.5. In certain situations, pipeline location markers may be required in heavily developed urban areas. If necessary, asphalt/concrete markers or curb/sidewalk markers may be used to indicate HP or IHP pipeline locations. Ensure markers are securely placed in a visible location. Refer to S.P. 2-18-01 for marker installation.

8.6. Place the marking over the underground pipeline, locator wire or other facility using one or more of the following methods:

8.6.1. Using stakes, paint, or other applicable manner that indicates either:

a. the approximate centerline of the underground facility; or

b. the approximate outside dimensions of both sides of the underground facility.

8.6.2. When electrical continuity is unavailable, use dimensions shown on maps or service cards to measure and mark the location.

8.6.3. Ensure horizontal measurement from mark(s) locating pipe or facilities to the actual location of pipe or facilities meets the requirements per applicable state law.

8.6.4. If multiple pipelines or facilities exist at location request site, ensure the marking indicates the number of pipelines or facilities. Mark each pipeline and/or facility individually.

8.6.5. Mark pipelines across owner's property at property lines and enough marks along pipeline to show pipeline direction and changes in direction.

8.7. Notify High Pressure Construction personnel if excavation will cross or be near high pressure feeder lines. High Pressure Construction will notify Gas Control, if they deem necessary.

8.8. Contact excavator for on-site meeting, if excavation will occur near high pressure facilities.

8.9. Notify excavator of temporary marking and how to identify the markings, where practical.

8.10. Do not provide pipeline depth measurements, except where visually confirmed.

8.11. Document action taken when locating facilities with the location request.

8.11.1. The following items should be noted:

a. Date and time of location was marked.

b. Address or description of location site.

c. Description of markings (painted, staked or flagged).

8.11.2. The following items may be noted:

a. Document area marked, including mains and services, using pictures or other appropriate means.

b. Any unusual circumstances encountered, if applicable.

c. Excavator contact, if present.

8.12. Notify excavator (within 48 hours of receipt of the request) if Company has no underground facilities in the area of the proposed excavation.

9. INSPECTION OF UNDERGROUND FACILITIES

NOTE:	*Inspections are required for all pipelines with an MAOP in excess of 60 psig.*

9.1. Monitor all excavations to verify the integrity of the underground facilities. Facilities may not be exposed during construction activities.

9.2. Contact Engineering for stress analysis of pipeline when conducting blasting activities. See Standard Practice 1-01-04.

9.3. Ensure a leakage survey is performed on underground facilities whenever blasting has occurred near the underground facilities.

9.4. Ensure a Corrosion Detection Report, form 51568, is completed after inspection of an exposed pipeline for corrosion. Refer to S.P. 7-35-01.

9.5. Ensure proper authorities are notified of damage to pipeline or facilities.

9.6. Upon discovery of damage to underground facilities, ensure the damaged facility is examined and repaired, as required.

9.7. Integrity Management personnel will record all excavation damages into a central database and the root cause analysis of such damages.

10. EXCAVATION RESTRICTIONS

NOTE:	*Refer to S.P. 2-17-02 for excavating and backfilling procedures.*

10.1. Ensure adequate support is provided for underground facilities which may be weakened or stressed by excavation activities.

10.2. Do not allow boring, tunneling or pile driving within a close proximity to Company facilities when possible damage can occur to Company facilities.

10.3. Ensure backfilling around Company High Pressure underground facilities is accomplished in a manner which provides maximum support to any exposed Company facilities.

10.4. Blasting Restrictions.

10.4.1. Engineering approval of blasting plan is required prior to blasting near or adjacent to Company pipelines or facilities.

10.4.2. Notify Gas Control if blasting operations are near high pressure pipelines or facilities.

10.5. Hand Exposing Buried Lines.

10.5.1. State laws require excavating with hand tools until the excavator has determined the exact location of the underground facility. Proximity requirements for manual excavation for states are as follows:

a. Arizona - 24".

b. California - 24".

c. Colorado - 18".

d. Idaho - 24".

e. New Mexico - 18".

f. Utah - 24".

g. Wyoming - 24".

11. ENCROACHMENT GUIDELINES FOR TRANSMISSION AND DISTRIBUTION HIGH PRESSURE PIPELINES

CAUTION: *The following guidelines are for Company employees and are not to be discussed with or given to the general public. Consult Right of Way Department when questions arise concerning encroachment guidelines.*

NOTE: *Minimum cover is measured from the top of pipe to top of soil/rock.*

11.1. Ensure at all times, buried transmission lines have a minimum cover of (normal soil/consolidated rock):

11.1.1. 30"/18" - Pipelines in Class 1 locations.

11.1.2. 36"/24" - Pipelines in Class 2, 3 and 4 locations.

11.1.3. 36"/24" - Pipelines in drainage ditches of public roads and railroad crossings.

11.2. Maximum cover not to exceed 60" unless approval is obtained from Questar.

11.3. No vehicular or heavy equipment crossing (except those for which the pipeline was originally designed for) will be allowed unless advance approval is obtained from Questar.

11.4. All waterway crossings must be maintained to a minimum of 48 inches of cover as measured from the bottom of the waterway to the top of the pipe (normal soil).

11.5. Provide 48 hours' notification in advance of the commencement of any construction activity involving Questar's right of way.

11.6. Questar may, at its sole discretion, choose to have a representative present during any construction or maintenance activities.

11.7. No structures (including poles, guys, anchors, etc.) may be constructed or placed within the easement. 5 feet, if no easement is defined.

11.8. Overhead power and telephone lines crossing the pipeline must be a minimum of 25 feet above the ground and located a minimum of 25 feet from a gas escape vent (relief valve, blow down valve, etc.).

11.9. No structure may overhang the easement so that access to or within the easement is impeded.

11.10. No trees, shrubs or other deep-rooted plant may be planted or grown within 10 feet of the pipeline.

11.11. Wood or chain-link type fencing is permissible within the easement. However, fencing running parallel to the pipeline must be offset at least 10 feet in either direction from the center line of the pipeline. Poles for fencing running perpendicular to the pipeline must not be set within 5' of the pipeline center line. Masonry or other types of fences will require prior approval of Questar.

11.12. A minimum of 12" of clearance must be provided between the pipeline and any utility lines or pipes crossing the pipeline. Utility lines or pipes must cross the pipeline at an angle not less than 45° and have direct burial warning tape not more than 18 inches and not less than 12 inches above the lines.

11.13. Buried power and communication line crossings of the pipeline must be installed in accordance with the guidelines of the most recent National Electric Code and any other applicable law, rule, regulation or order and encased in a rigid, non-metallic conduit across the entire width of the easement, unless written approval is given by Questar for a metallic conduit. All buried power line crossings must maintain a minimum clearance from the pipelines as follows:

11.13.1. 24" - 0 - 600 volts.

11.13.2. 30" - 601 - 22,000 volts.

11.13.3. 36" - 22,001 - 40,000 volts.

11.13.4. 42" - above 44,000 volts.

11.14. All metallic lines crossing the pipeline must have a protective coating for a minimum of 10 feet on either side of the pipeline. Each metallic line must have cathodic protection test leads that shall be brought above ground in a permanent protective conduit.

11.15. Buried power lines parallel to the pipeline must be offset a minimum of 10 feet. All other buried lines parallel to the pipeline must be offset a minimum of 6 feet.

11.16. All sewer lines in the easement are limited to water-tight lines only. No leach fields or drain fields are allowed in easement.

12. NOTIFYING ONE-CALL CENTERS OF INTENDED EXCAVATIONS

12.1. Ensure company contractors and/or company crews notify one-call centers of any intended excavation activity.

NOTE:	*Questar participates in the local one-call systems in each of the states that it operates in.*

12.2. In an emergency situation, ensure that one-call center is informed that this is an emergency request.

12.3. Provide one-call center 48 hours (Arizona, California, Idaho and New Mexico) or two [2] full business days (Colorado, Utah and Wyoming) notice on all excavation activity.

12.4. In areas where a one call center does not exist, notify the affected utilities of intended excavation activity.

12.5. Begin excavation only if:

12.5.1. All underground facilities have been located and marked or.

12.5.2. 48 hours or two [2] full business days have elapsed from the time of initial notice or renotification.

12.5.3. In the event of an emergency.

12.6. The damage prevention program includes participation in state qualified one-call systems, as well as the National One-Call System.

Table 1

EXCAVATION LOCATION	ONE-CALL CENTER NAME	TOLL-FREE NUMBER	MINIMUM ADVANCE NOTICE	MAXIMUM ADVANCE NOTICE	VALID LOCATE DURATION
United States	National One-Call System	811	2 Full Business Days	Refer to State info	
Arizona	Arizona Blue Stakes	1-800-782-5348	2 working days	15 working days	15 working days
California	Underground Service Alert of Southern California	1-800-227-2600	2 working days	14 calendar days	14 calendar days
Colorado	Utility Notification Center of Colorado	1-800-922-1987	2 full business days	9 working days	30 working days
Idaho	Dig Line	1-800-342-1585 (Inside Idaho) 208-342-1585 (Outside Idaho)	2 working days	10 working days	As long as clearly visible
New Mexico	New Mexico One Call System	1-800-321-2537	2 working days	10 working days	As long as clearly visible
Utah	Blue Stakes Center	1-800-208-2100 532-5000 (Salt Lake City area only)	2 full business days	7 days	14 calendar days
Wyoming	One Call of Wyoming	1-800-849-2476	2 full business days	14 days	As long as clearly visible
Note: Emergency locate request can be made under exceptional circumstances.					

Questar Standard Practice

3-70-01 ODORIZATION PROCEDURES

1. PURPOSE

This Standard Practice describes the process for maintaining and documenting required gas odorization levels. These procedures will be followed by personnel inspecting odorant equipment and conducting odor tests. This Standard Practice applies to both Questar Gas Company (QGC) and Questar Pipeline Company (QPC). QGC personnel will conduct odorant sampling operations as a contract function for QPC.

2. REFERENCES

2.1. Company DOT Operator Qualification Program.

2.2. Operating manual for Heath Odorator.

2.3. Operating manual for YZ DTEX Odorant Detector.

2.4. AGA Odorization Manual.

2.5. Standard Practice 4-05-06, "Gas Odorant Injector Operating Procedure."

2.6. Standard Practice 8-10-00, "Personal Protective Equipment."

2.7. Standard Practice 8-11-03, "Hazard Communication Standard."

3. DEFINITIONS

3.1. Lower Explosive Limit - the lowest concentration of gas in a gas/air mixture that will burn (approximately 5% for natural gas).

3.2. Material safety data sheet (MSDS) - electronic, written or printed material that provides information regarding characteristics of products and materials, health hazards associated with materials, and appropriate safety measures to be observed when exposed or using specified products or materials. Refer to Standard Practice 8-11-03 for explanation of information contained on MSDS.

3.3. Odorant - a chemical compound (usually a cyclic sulfide or a mercaptan) used to blend with a combustible gas that has no natural detectable odor. The standard specification is a blend of 50% tetrahydrothiophene (THT) and 50% tertiary butyl mercaptan (TBM). An odorant blend of 80% TBM and 20% Methyl ethyl sulfide (MES) is used in most vapor odorizers.

3.4. Odorizer - a pump or other device used to introduce odorant into the gas of a piping system.

3.5. Odor Meter - a meter used to determine the percent concentration of gas in air by conducting odor tests. Refer to manufacturer's literature for details on specific operation requirements.

3.6. Odor Test - a DOT required test that a person with a normal sense of smell performs using an odor meter to determine at what concentration the natural gas has a readily detectable odor.

3.7. Sniff Test - a test for odorant presence where gas from a pipeline, appliance, etc. is "sniffed" with the nose to verify the presence of odorant in the gas.

4. SAFETY

CAUTION:	*Excessive exposure to odorant may cause headache, coughing, wheezing, nausea, vomiting and irritation to the eyes and mucus membranes.* *Odorant is also flammable with a low flashpoint. If the odorant is burning, toxic combustion products such as carbon monoxide and sulfur dioxide will be produced.* *Odorant vapor is heavier than air, which could result in the accumulation of odorant vapors in confined areas.*

4.1. Ensure appropriate personal protective equipment is worn when exposed to or handling odorant. Refer to Standard Practice 8-10-00 and Standard Practice 4-05-06.

4.2. Refer to appropriate MSDS for odorant health hazards and safety information.

5. PERSONNEL QUALIFICATIONS

5.1. Personnel responsible for performing covered task(s) outlined herein will be qualified or will be directed and observed by someone who is qualified as outlined in the Company DOT Operator Qualification Program.

5.2. Personnel will be familiar with procedures and safety precautions outlined herein.

5.3. Personnel performing odorant tests per paragraph 8 shall be tested on a periodic basis to verify they do not have an impaired sense of smell. Refer to Company Operator Qualification Program for applicable records.

6. ODORANT STATION INSPECTION

6.1. Inspect the odorant introduction equipment at all assigned odorant stations for proper operation.

6.2. For specific instructions on the use and maintenance of odorant equipment, refer to manufacturer's literature.

6.3. The minimum inspection frequency for the various types of equipment is listed in Table 1.

TABLE 1

Recommended Inspection Frequency for Odorization Equipment

Equipment	Inspection Frequency
Pump with Telemetry	Monthly
Pump without Telemetry	Weekly
Pulse Bypass	Weekly
Bypass	Monthly
Wick	Annually

NOTE:	*Wick odorization vessels are filled during the annual inspection of the regulator station. Wick odorization vessels may be filled more frequently where experience indicates the necessity.*

6.4. Complete the Odorant Injection Rate Report for pump type injection equipment. Record the following information on this report.

6.4.1. Location: State, County, City, Address, Description, Longitude, Latitude, and Elevation.

6.4.2. Date the current rate was calculated.

6.4.3. Pounds of odorant used since the previous rate was calculated.

6.4.4. Gas volume metered in MMCF since the previous rate was calculated.

6.4.5. Odorant injection rate in lbs/MMCF. Odorant used in pounds divided by the gas volume metered in MMCF.

6.5. Refer to paragraph 11 (Records) for information on submission of completed reports.

7. ODOR TEST EQUIPMENT CALIBRATION

NOTE:	*Each piece of odor test equipment will be assigned a unique identification number by the QGC Measurement and Control Supervisor.*

7.1. Ensure that a unique identification number is assigned to the odor test equipment being calibrated. Contact the QGC Measurement and Control Supervisor if the odor test equipment does not have an identification number. Do not use odor test equipment that does not have a unique identification number.

7.2. Equipment being used for odor tests must be calibrated at the manufacturer's recommended frequency (normally yearly). Refer to manufacturer's literature to verify calibration frequency.

NOTE:	***DO NOT USE** equipment that has lapsed past its calibration date for conducting odor tests.* *Ensure any replacement parts (i.e. tubing, etc.) meet or exceed manufacturer's recommendations.*

7.3. Complete the Odorant Equipment Calibration Report. Record the following information on this report:

7.3.1. Questar assigned unique identification number

7.3.2. Make

7.3.3. Model

7.3.4. Serial Number

7.3.5. Previous Calibration Date

7.3.6. Current Calibration Date

7.4. Refer to paragraph 11 (Records) for information on submission of completed reports.

8. ODOR TEST

NOTE:	*The AGA odorization manual recommends the following practice to be followed prior to conducting odor tests: Testers should avoid smoking, chewing tobacco or eating for some time before testing to avoid problems with olfactory interference.*

8.1. Obtain test reports from Questar intranet site.

8.2. Conduct odor test at the sites listed on the Odor Test Report. Record the following information on this report.

8.2.1. Type: Baseline, Random, or Wick.

8.2.2. Location: State, County, City, Address, Description, Longitude, Latitude, and Elevation.

8.2.3. Date of test.

8.2.4. Test result, percent natural gas in air that is readily detectable by a person with a normal sense of smell.

NOTE:	*The target odorization value is 0.25% gas in air.*

8.2.5. Person who performed the test.

8.2.6. Equipment number used in conducting the test (Questar assigned unique identification number).

8.3. Perform odor tests with authorized test equipment only (i.e. equipment that has a unique Questar identification number and is current on calibration).

8.4. For specific instructions on the use and maintenance of odor test equipment refer to the manufacturer's literature.

8.5. Refer to Figure 1 for testing process flow diagram.

8.6. If the test result is greater than or equal to 1%, do the following:

NOTE:	*It is possible that during odor testing, the tester may become desensitized to the odorant resulting in higher test results.*

8.6.1. Perform a second test at the same site. The second test should be conducted by another person who has not conducted an odor test that day.

8.6.2. Record the test information of the second test including the value. If the value is still greater than or equal to 1%, immediately notify the Measurement and Control Area Supervisor.

8.6.3. Measurement and Control personnel will implement corrective action as soon as possible.

8.6.4. Retest that site for required odorant levels once Measurement and Control has implemented corrective action, preferably within 72 hours. Record information of retest. If value still greater than or equal to 1% repeat steps outlined in paragraph 8.6.

NOTE:	*Multiple values will be recorded on a single report for sites that required corrective action to achieve proper odorization.*

8.7. If the value is less than 1%, record the test information on the report.

8.8. Repeat this process for all test sites assigned until all values are less than 1%.

8.9. Refer to paragraph 11 (Records) for information on submission of completed reports.

NOTE:	*Typically, when an odor test is required due to an incident, the local incident investigation team will request that this test be performed.*

8.10. In the event of a federally reportable incident (and due to the nature of the incident an odor test is warranted), an odor test should be taken as soon as possible. The selected site for this odor test should be as close to the location of the incident as possible while maintaining safety.

9. ODOR TEST SITE SELECTION

NOTE:	*Since systems can vary greatly in size and configuration, it is the responsibility of the Measurement and Control Area Supervisor to determine type, quantity and location of odor test sites for each odorant system.* *Sites can be activated or deactivated depending on the needs of the system. For example, if a site was to be tested only once for some special circumstance (e.g. an incident), a test site would be created, testing performed and then the site could be deactivated after testing was completed and test site is no longer required.*

9.1. Select sites for odor tests based on the following criteria:

9.1.1. Baseline Sites:

a. Baseline sites are to be used in all systems with the exception of wick systems. Baseline test will typically be conducted in conjunction with random testing. However certain smaller systems do not warrant extensive random testing and will only have baseline tests. This could include but is not limited to large commercial or industrial users that have an isolated system.

b. Baseline site selection should include areas where odorant levels are likely to be lowest, such as dead ends, low or changing flow, isolated areas, and any other areas deemed necessary.

c. Testing interval for all active baseline sites for a given system will be required a minimum of 4 times per calendar year. Monthly is recommended.

9.1.2. Random Sites:

a. Random sites are to be used in large systems with a significant quantity of end users and large volumes of gas, typically odorized using pump type odorant injection equipment. In systems where random sites are used a minimum of 2 sites must be sampled each test cycle with the random pool, typically containing at least 4 times the number of random sites sampled.

NOTE:	*The random pool may be larger than the minimum listed above.*

b. All random sites in the pool will NOT be tested. Only active sites that are randomly selected from the pool will be tested.

c. Random site selection is based on the following algorithm:

RANDOM TEST SITE ALGORITHM:	
	This algorithm is used to generate random test sites. The number of random test sites tested is determined by the Measurement and Control Area Supervisor.
A.	*All active random sites for a particular system are placed in a list.*
B.	*These sites are then ordered by date of last test, beginning with the sites that have the oldest date of last test.*

C.	*A second list is then created by taking a subset of the first list (subset consists of 2 times the number of required random test sites). The sites for this second list are taken from the top of the first list.*
D.	*The first site on the second list is selected for testing.*
E.	*The other random test sites are selected at random from the remaining sites on the second list.* *This process will ensure that all random sites will eventually be selected and favors sites that have not been recently sampled, while still maintaining random selection.* *This algorithm is coded into the Odorization database.*

9.1.3. Wick Sites:

a. Wick sites are to be used on small isolated systems that serve only a few customers from a single regulator station that uses a wick type odorant induction method. These systems typically use very little odorant and consume relatively small volumes of gas.

b. Wick sites will be placed on the same Odor Test Report as a Baseline/Random system even though each wick site is its own system.

c. Wick site selection should be at or near the end of the system. Only one (1) site per system is required. If it is determined that more than one (1) site is required to adequately monitor the odorant of this system then Baseline\Random testing should be conducted.

d. The test interval for all active wick sites is one time per calendar year. Recommended two times per year. .

10. SNIFF TEST TO DETERMINE PRESENCE OF ODORANT

NOTE:	*The sniff test is a recommended practice whenever work is being performed at locations where this is practical. The sniff test does not require documentation.*

10.1. Whenever an employee vents gas in the course of their work (new service line, main extension, appliance maintenance, etc.), it is recommended that a sniff test be conducted to verify there is an odor to the gas.

10.2. Report immediately to Supervisor or the Measurement and Control Area Supervisor if odor is low (difficult to detect) or has an unusual smell.

11. RECORDS

NOTE:	*Odorant reports (Odor Test report, Odorant Injection Rate report and Calibration report) are available and can be accessed on-line at Questar's intranet site. Historical records are also available on-line at this same site.* *The Measurement and Control Supervisor is responsible to ensure that these records are maintained and is responsible for the maintenance and support of the Odorization database.*

11.1. Upon completion of testing, original copies of the Odor Test Equipment Calibration Report, Odor Test Report, and Odorant Injection Rate Report are to be submitted to Pipeline Compliance.

11.2. Data from each report will be entered into the Odorization Database by Pipeline Compliance personnel.

11.3. Pipeline Compliance will maintain paper reports for a minimum of two years. Data in the electronic Odorization Database will be maintained for a minimum of five years.

11.4. In the event of an incident and where it is applicable, reports documenting proper odorization should be maintained indefinitely and as part of the incident report file maintained by Pipeline Compliance.

Odor Testing

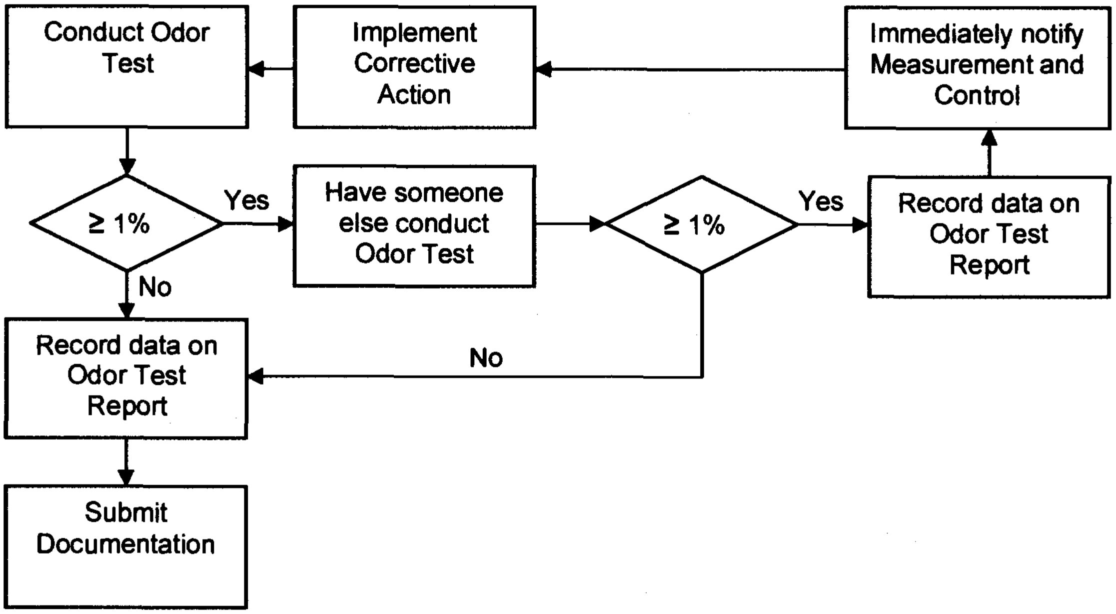


Figure 1

Questar Pipeline Standard Practice

1-01-03 DESIGN REQUIREMENTS FOR UPRATING PIPELINES AND PIPELINE FACILITIES

1. PURPOSE

This Standard Practice outlines design requirements for increasing MAOP (uprating) of pipeline or pipeline facility. This procedure will be followed by personnel responsible for design requirements associated with uprating pipelines and pipeline facilities.

2. REFERENCES

2.1. Standard Practice 1-01-02, "Designing Steel Piping Systems."

2.2. Standard Practice 1-90-01, "Test Requirements for Pipelines and Pipeline Facilities."

2.3. Standard Practice 1-97-03, "Evaluation and Adjustment of Class Location Designation."

2.4. Standard Practice 1-97-04, "Determining Maximum Allowable Operating Pressure (MAOP) for Steel or Plastic Pipelines."

2.5. Standard Practice 2-30-01, "Uprating Pipelines and Pipeline Facilities."

2.6. Company DOT Operator Qualification Program.

2.7. Company Integrity Management Plan.

3. DEFINITIONS

3.1. Line Job - written schedule and procedure to facilitate pipeline maintenance or emergency repair.

3.2. Uprating - increasing MAOP of pipelines or pipeline facilities.

4. SAFETY – No specific instructions required.

5. PERSONNEL QUALIFICATIONS

5.1 Personnel responsible for design requirements associated with uprating pipelines and pipeline facilities will be familiar with procedures outlined herein.

5.2 Ensure that individuals responsible for conducting uprating activities are qualified as specified in the Company DOT Operator Qualification Program.

6. PRELIMINARY ECONOMIC REVIEW

Prior to conducting uprating of pipeline facilities, Engineering Department should conduct preliminary economic review (not mandatory under DOT regulations) which includes:

6.1. Review age of pipeline and facilities such as valves, slug catchers, drips, flanges, etc., to determine approximate dollar amount of items that may need replacement.

6.2. Determine approximate amount of labor-hours needed to complete uprating.

6.3. Explore possibility of transporting gas through other company pipelines allowing achievement of same end result.

6.4. Determine approximate amount of gas loss due to blowdowns and other activities associated with uprate.

6.5. Consider cost of installing new pipeline or facility as compared to uprating existing equipment and retirement/salvage costs of existing facilities.

6.6. Consider cost/impact of disrupting existing services, if applicable.

7. REVIEW OF PIPELINE/FACILITY HISTORY

7.1. Review design, construction and operating & maintenance history of pipeline to be uprated or converted.

7.2. Ensure a visual right-of-way and pipeline inspection is performed to identify physical defects and operating conditions.

7.3. Correct unsafe defects and conditions once they are identified.

7.4. See Standard Practice 1-90-01 for pipeline pressure testing requirements in accordance with 49 CFR 192.503 to substantiate maximum allowable operating pressure.

7.5. Include leaks and previous pressure tests for establishing present MAOP and determine existing authorized MAOP of pipeline or facility. Evaluate potential for stress corrosion cracking that could be aggravated by additional pressure testing (consult with Integrity and Corrosion Engineering, as appropriate).

7.6. Determine if proposed MAOP is safe after reviewing pipeline segment or facility history. Also, ensure proposed MAOP will not exceed limitations for existing steel pipe and components as outlined in Standard Practice 1-01-02 or 1-97-04.

7.7. Determine if repairs, alterations, or additional pipeline equipment are needed to ensure pipeline or facility conforms to Company standards.

7.8. For transmission lines and feeder lines verify class location of pipeline or facility. Ensure class location study is conducted in addition to HCA review. Refer to Standard Practice 1-97-03 and company Integrity Management Plan.

7.9. Determine if existing sectionalizing block valve spacing is adequate for class location, if there has been change in class location determined in paragraph 7.4. See Standard Practice 1-01-02 to determine required spacing of sectionalizing block valves.

8. GENERAL UPRATING DESIGN REQUIREMENTS

8.1. Ensure FERC regulated pipelines are certified by FERC to operate at higher MAOP. Contact Certificates department for this determination.

8.2. Complete Management of Change (MOC) form prior to uprating (refer to company Integrity Management Plan for details on MOC process).

8.3. Ensure individuals performing uprate are Operator Qualified. Contact Operations Training department for this qualification process. Refer to Company Operator Qualification Program.

8.4. When uprating any segment of pipeline, prepare written plan that will establish procedures for conducting uprating. Consider any of the following applicable items in preparing plan:

NOTE:	*Written plan is required pursuant to DOT regulations (§192.553. b and c) and should be included with permanent records retained pursuant to paragraph 11.*

8.4.1. Proposed MAOP, amount of increase needed to obtain proposed MAOP, and purpose for proposed MAOP.

8.4.2. Class location(s) of segment to be uprated.

8.4.3. Addition of sectionalizing block valves, if any, to meet valve spacing requirements (refer to Standard Practice 1-01-02) if there has been change in class location.

8.4.4. Review of requirements of Standard Practice 1-97-04 to ensure proposed MAOP is allowable.

8.4.5. Description of facility such as schematic map. Description should clearly define pipeline segment to be uprated and all adjacent pipelines and mains. Description should also include construction dates, outside diameter (O.D.), wall thickness, and grade of pipe. Also identify MAOP of any laterals, side connections, and identification of and maximum allowable working pressure of other appurtenances.

8.4.6. Progress schedule for proposed work.

8.4.7. Definition and assignment of responsibilities for completion of various phases of segment uprating. Assignments should include the following:

a. Line job (prepared by Gas Control or QGC Operations for feeder lines).

b. Verification to ensure compliance with Company Standards has been accomplished before proceeding from one phase to the next.

8.4.8. Sequence of steps to isolate adjacent piping from segment to be uprated.

8.4.9. Determination that adequate pressure will be maintained during uprating process.

8.4.10. Instructions for personnel involved with uprating procedure, including references to Standard Practice 2-30-01 "Uprating Pipelines and Pipeline Facilities."

8.4.11. Advance notification to any customers affected by uprating.

8.4.12. Alterations to any existing pressure reduction or relief equipment to prevent accidental over pressuring. Verify existing pressure reduction and relief equipment still meets applicable capacity requirements consistent with proposed MAOP.

8.4.13. Precautions to be taken to protect employees and general public during uprating procedure.

NOTE:	*Refer to Standard Practice 1-90-01 for test pressure limits.*

8.4.14. Provisions to monitor and protect adjacent facilities to ensure MAOP's on lower pressure facilities are not exceeded during uprating.

8.4.15. Provisions for final leak survey using an instrumented leak detection device at completion of uprating.

8.4.16. Consider aerial patrol during uprating.

8.4.17. Method to dry out or purge pipeline of any test media.

8.4.18. Identification of required environmental permits

8.5. Except as provided in paragraph 9.2., ensure new MAOP for pipeline segment does not exceed maximum allowed for new segment of pipeline constructed of same materials in same location.

8.6. Whenever uprating requires pressure increases be made in increments (see paragraphs 9.4 and 10.2), specify gradual pressure increase in accordance with the following:

8.6.1. At the end of each incremental increase, pressure will be held constant while entire segment is checked for leaks.

8.6.2. Each leak detected will be repaired before further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during pressure increase and it does not become potentially hazardous.

8.6.3. Consult with management to determine when a leak is considered not to be potentially hazardous.

8.6.4. Specify repair of all non-hazardous leaks, as determined in paragraph 8.6.2, prior to completion of uprating. Specify that non-hazardous leaks not repaired prior to completion of uprating will be periodically monitored and scheduled for repair at earliest practical time.

9. DESIGN REQUIREMENTS FOR UPRATING STEEL PIPELINES TO OPERATE AT A PRESSURE THAT PRODUCES A HOOP STRESS OF 30 PERCENT OR MORE OF SMYS

9.1. Before increasing operating pressure above previously established MAOP, complete the following:

9.1.1. Review design, operating and maintenance history, and previous testing of pipeline segment;

9.1.2. Determine proposed pressure increase is safe and consistent with Company standards; and

9.1.3. Make any repairs, replacements, or alterations necessary for pipeline segment to operate safely at increased pressure.

9.1.4. Isolate pipeline segment from any adjacent segments which will operate at lower pressure; and

9.1.5. If pressure in uprated pipeline is to be higher than pressure to be delivered to lateral lines, taps or other interconnecting pipelines, specify isolation or installation of pressure control equipment on each such line. Specify pressure control equipment is tested appropriately and incorporates a means of overpressure protection.

9.2. For pipelines constructed before September 12, 1970, specify MAOP not greater than that allowed in accordance with Standard Practice 1-97-04 "Determining MAOP for Steel and Plastic Pipelines," using as test pressure the highest pressure to which segment of pipeline was previously subjected (either in strength test or in actual operation).

NOTE:	*When MAOP of pipeline segment must be increased above highest pressure to which segment was previously subjected, either in strength test or in actual operation, retest of segment must be performed regardless of pipeline segment's age.*

9.3. Design uprating of pipeline segments not meeting requirements of paragraph 9.2 above by using one of the following methods:

9.3.1. Specify test for segment in accordance with requirements for new line of same material in same location.

9.3.2. Establish increased MAOP for segment of pipeline in Class 1 location which has not been previously tested and:

a. It is impractical to test it in accordance with paragraph 9.3.1 above;

b. New MAOP does not exceed 80 percent of that allowed for new line of same design in same location; and

c. New MAOP is consistent with condition of segment of pipelines and design requirements of this Standard Practice.

9.4. For uprating under paragraph 9.2 and 9.3.2, specify pressure increase increments to be used. Incremental increases will be equal to 10 percent of present MAOP or 25 percent of total pressure increase, whichever produces fewer number of increments.

10. DESIGN REQUIREMENTS FOR UPRATING STEEL PIPELINES TO OPERATE AT PRESSURES THAT PRODUCE A HOOP STRESS BELOW 30 PERCENT OF SMYS AND PLASTIC PIPELINES

10.1. Before increasing operating pressure above previously established MAOP, complete the following:

10.1.1. Review design, operating, and maintenance history of segment pipeline is completed;

10.1.2. Conduct leakage survey unless survey has been conducted within one year of proposed uprating start date. Repair all leaks prior to start of uprating unless leaks are determined not to be potentially hazardous or are monitored during uprating pressure increases and do not become potentially hazardous;

10.1.3. Make any repairs, replacements, or alterations in pipeline segment necessary for safe operation at increased pressure;

10.1.4. Reinforce or anchor offsets, bends, and dead ends in pipe joined by compression couplings to prevent failure of pipe joints, if offset, bend, or dead end is exposed in excavation.

10.1.5. Isolate pipeline segment from any adjacent segments which will operate at lower pressure; and

10.1.6. If pressure in uprated pipeline is to be higher than pressure to be delivered to lateral lines, taps, mains, services or other interconnecting pipelines, isolation or installation of pressure control equipment is specified on each such line. Specify pressure control equipment be tested appropriately and incorporate means of overpressure protection, when required.

10.2. Specify pressure increases be made in increments. Incremental increases will be equal to 10 PSIG or 25 percent of total pressure increase, whichever produces fewer number of increments. Whenever requirements of paragraph 10.1.6 apply, specify at least two approximately equal incremental increases.

11. RECORDS

11.1. Retain for life of uprated segment a record of each investigation, of all work performed, and of each pressure test conducted in connection with uprating as required by this Standard. File record in appropriate work order file. Include completed "Uprating Review for Pipelines and Facilities" form (Figure 1) as permanent record.

11.2. Use "Uprating Review for Pipelines and Facilities" Form (Figure 1) to ensure all areas outlined herein are documented before and during uprating.

Figure 1

UPRATING REVIEW FOR PIPELINES AND FACILITIES			
			Work Order No.
Name of Facility:		Location:	
Class Location:	Present MAOP:	Basis of Present MAOP (Design, Test, etc.):	
Date MAOP Determined:	Required MAOP	Hoop Stress of SMYS:	

PURPOSE OF UPRATING

Originating Person or Department:	
	Attached Explanation ☐

DESIGN REVIEW

Person or Department Assigned:	☐ Pipe Specs ☐ Road Xing ☐ Valve Specs ☐ Flanges ☐ Fittings ☐ Fabrications	
☐ Branch Connections ☐ Flexibility ☐ Supports ☐ Valve Spacing ☐ Relief Valves ☐ Instrument Piping ☐ Metering ☐ Cover		
☐ Other (Describe):	Records ☐ Attached ☐ Available	Remarks:

OPERATIONS AND MAINTENANCE HISTORY

Person or Department Assigned	Date In Service	Operating Pressure (psig)	Any Leaks ☐ Yes ☐ No Any Failures ☐ Yes ☐ No If Yes, give detail in remarks

Corrosion Protection Coated ☐ Yes ☐ No	Type	Year	Cathodic Protection ☐ Yes ☐ No	Type	Year Installed

Last Leak Survey Date	New Leak Survey Required? ☐ Yes ☐ No	Number of Pressure Gauges and Specified Locations

Records ☐ Attached ☐ Available	Remaks:

PREVIOUS TESTING

Person or Department Assigned	Date Tested	Pressure (psig)	Duration	Medium	Failures ☐ Yes ☐ No
Tested By	Records ☐ Attached ☐ Available		Recommendation ☐ Attached	Received By	Date

Comments

REPAIRS, REPLACMENTS, ALTERATIONS NEEDED

Person or Department Assigned	Number of Steel Service Lines Required (60 psig and above)

Repair Remarks:
☐ Information Attached

Replacement Remarks:
☐ Information Attached

Alteration Remarks:
☐ Information Attached

UPRATING REQUIREMENTS

Was the Pipeline Constructed Before September 12, 1970? ☐ Yes ☐ No	Date of Construction	Will the New MAOP Exceed Either Previous Subjected Pressure or Previous Strength Test? ☐ Yes ☐ No	If No, Basis for New MAOP

Is the Entire Pipeline Located in a Class 1 Area ☐ Yes ☐ No	If Yes, Complete the Following	Has the new Pipeline had a Prior Test ☐ Yes ☐ No	Is It Practical to Test Now ☐ Yes ☐ No	Will the New MAOP Exceed 50% of that Allowed for the New Pipeline ☐ Yes ☐ No

Is a New Pressure Test Required ☐ Yes ☐ No	Date of Test	Test Pressure	Medium	Duration of Test	Any Leaks ☐ Yes ☐ No	Any Failures ☐ Yes ☐ No
Report ☐ Attached	Remarks:					

Were Pressure Increases Made in Increments ☐ Yes ☐ No	If Yes, Number of Increments	Increments Were: ☐ 10 psig (Less than 30% of SMYS or plastic) ☐ 10% of Original Pressure ☐ 25% of Total Pressure Increase	Was Pressure Held Constant at Each Increase to Check for Leaks ☐ Yes ☐ No

Were Leaks Repaired ☐ Yes ☐ No	If Not Repaired, Monitored ☐ Yes ☐ No	If leaks Were Not Repaired, Date Repair Scheduled

Figure 1 (continued)

WRITTEN PLAN								# OF INCREMENTS AND % OR PSIG PER INCREASE							
								PRESSURE INCREASE #1		PRESSURE INCREASE #2		PRESSURE INCREASE #3		PRESSURE INCREASE #4	
PIPE SEGMENT	EXIST. PIPE SIZE	PIPE O.D.	PIPE W.T.	PIPE SPEC.	PIPE MATERIAL	CLASS LOCATION	% SMYS NEW MAOP	FROM	TO	FROM	TO	FROM	TO	FROM	TO
1															
2															
3															
4															
5															
6															
7															
8															

DISTRICT REGULATOR STATION #

DISTRICT REGULATOR STATION #

DISTRICT REGULATOR STATION #

DISTRICT REGULATOR STATION #

ADDITIONAL INFORMATION

DISTRIBUTION: PREPARE ORIGINAL ONLY FOR DISPOSITION WITH ATTACHMENTS TO W O PACKET OR ENGINEERING FILE
INFO COPIES OF UPRATING DISTRIBUTED TO GAS CONTROL, SYSTEM INTEGRITY, PIPELINE COMPLIANCE, OPERATIONS ENGINEERING

Figure 1

Questar Pipeline Standard Practice

5-00-02 REPAIRING STEEL PIPELINES

1. PURPOSE

This Standard Practice describes the procedures to be followed when making repairs to damaged steel pipelines. These procedures will be followed by qualified and experienced company personnel trained to repair steel pipelines.

2. REFERENCES

2.1. Standard Practice 2-10-01, "Welding on Steel Pipe and Facilities."

2.2. Standard Practice 2-10-02, "Qualified Welding Procedures."

2.3. Standard Practice 2-17-01, "Blowdown Procedures and Temporary Pressure Reduction."

2.4. Standard Practice 2-17-02, "Excavating and Backfill Procedures."

2.5. Standard Practice 2-17-03, "Purging Pipelines and Pipeline Facilities."

2.6. Standard Practice 2-32-02, "Hot Tapping Gas Pipelines."

2.7. Standard Practice 3-15-01, "Inspection and Testing of Production Welds."

2.8. Standard Practice 5-00-01, "Isolating a Section of Pipeline or Pipeline Equipment""

2.9. Standard Practice 7-35-01, "Inspecting Aboveground and Exposed Portions of Steel Pipelines and Facilities for Corrosion."

2.10. Standard Practice 8-10-01, "Eye and Face Protection."

2.11. Standard Practice 8-10-04, "Protective Clothing Program."

2.12. Standard Practice 8-12-01, "Portable Fire Extinguishers."

2.13. Standard Practice 8-13-01, "Respiratory Protection Program."

2.14. Company DOT Operator Qualification Program.

3. DEFINITIONS

3.1. Dent - a depression in the pipe wall that produces a gross disturbance in the curvature of the pipe without reducing the pipe wall thickness. Depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

3.2. Gouge - a long depression in the pipe wall that not only produces a disturbance in the curvature of the pipe wall but reduces the pipe wall thickness.

3.3. Hazardous Atmosphere - an atmosphere which exposes employees to risk of death, incapacitation, injury or acute illness from one or more of the following: flammable gas, vapor or mist in excess of 10 percent of its lower explosive limit; an atmosphere with an oxygen concentration below 19.5 percent or above 23.5 percent; likely exposure to a substance for which a permissible exposure limit has been established in Subpart Z of 29 CFR Part 1910 (contact Safety Department); or any other atmospheric condition recognized as immediately dangerous to life or health.

3.4. SMYS - Specified minimum yield strength (of pipe).

3.5. MAOP - Maximum allowable operating pressure.

4. SAFETY

4.1. Ensure all necessary precautions are taken for the safety of the general public and company personnel whenever leaking gas is detected. The Emergency Plan addresses priorities and considerations when a gas leak is discovered on a pipeline.

4.2. Use appropriate eye and face protection, protective clothing, respiratory equipment, or other safety equipment, as specified or otherwise needed. Refer to Standard Practices 8-10-01, 8-10-04 and S.P. 8-13-01.

4.3. Remove all potential sources of ignition from the area whenever gas is vented or leaking to the atmosphere.

4.4. Refer to Standard Practice 2-17-02 for necessary precautions to be taken to protect personnel from hazards of unsafe accumulations of vapor or gas, including availability of needed emergency rescue equipment.

4.5. Ensure fire extinguishers are available and manned whenever gas is vented or leaking to the atmosphere. Refer to Standard Practice 8-12-01.

4.6. Keep all unnecessary personnel clear of area when gas is leaking.

4.7. Establish emergency exit routes from the pipeline work site and inform all personnel working on pipeline of exit routes.

5. PERSONNEL QUALIFICATIONS

5.1. Personnel responsible for performing covered task(s) outlined herein will be qualified or will be directed and observed by someone who is qualified as outlined in the Company DOT Operator Qualification Program.

5.2. Personnel will be familiar with procedures and safety precautions outlined herein.

6. PRELIMINARY EVALUATION OF DAMAGE SITE

NOTE:	*Damage to steel pipelines can be caused by outside sources, from internal or external corrosion to the pipe, or from a pipe material or construction defect.*

6.1. Establish and maintain contact with Gas Control. Inform Gas Control and appropriate supervision of the extent of damage to the pipeline, assistance needed to make repairs, and all progress made to complete repairs.

6.2. If required, reduce pipeline pressure as determined by Engineering.

NOTE:	*Care should be taken when excavating around the pipe so that it is not further damaged.*

6.3. Determine if pipeline is leaking or just dented or gouged. If pipeline is dented or gouged, determine if pipeline is pressurized. Inspect for corrosion in conformance with Standard Practice 7-35-01.

6.4. Examine the pipe on each side of the known impairment to determine if some degree of impairment may have occurred beyond the area of immediate concern.

6.5. Determine if it is feasible to make a permanent repair or if a temporary repair is necessary. If a temporary repair is made, permanent repairs must be done as soon as feasible.

NOTE:	*If it is not feasible to make a permanent repair of a leak, imperfection or damage at the time of discovery, a temporary repair will be accomplished by installing a properly designed bolt-on leak clamp or other suitable device (refer to Section 9 of this Standard Practice).*

6.6. Determine the type of imperfection, damage, weld or leak repair that is appropriate. If repair is due to corrosion that does not penetrate the pipe wall, refer to Standard Practice 7-00-01 to determine remaining strength of pipe and approved repair methods.

6.7. Determine location of nearest cathodic protection unit and shut down rectifier.

7. PERMANENT REPAIRS OF A STEEL PIPELINE THAT HAS BEEN ISOLATED (TAKEN OUT OF SERVICE) BY REPLACEMENT

7.1. Station personnel at valves used to isolate the pipeline segment.

7.2. Isolate and blowdown the pipeline following procedures outlined in Standard Practices 2-17-01 and 5-00-01. Normally, pipe cut-out and replacement welds will be "hot".

7.3. Ensure all gas-air mixtures are below 10% of the lower explosive limit before working on the pipeline.

7.4. Periodically check the area around the pipeline damage location to ensure no hazardous atmosphere exists.

7.5. Remove the damaged section of the pipeline by cutting out a cylindrical piece of pipe.

7.6. Replace the damaged section with a piece of pre-tested pipe of similar or greater strength design. Ensure the replacement section of pipe was tested to the pressure and time required for a new line installed in the same location.

7.7. Visually inspect and non-destructively test all field girth welds made to install a replacement section of pipe following the procedures outlined in Standard Practice 3-15-01.

7.8. Apply pipe coating over the repair and other disturbed areas.

7.9. If necessary, purge the pipeline following procedures outlined in Standard Practice 2-17-03. Repressurize and place line back in service.

7.10. Start up the cathodic protection unit when repairs are completed.

7.11. Complete all records documentation as outlined in section 10 of this Standard Practice.

8. PERMANENT REPAIR OF A STEEL PIPELINE THAT IS NOT ISOLATED BY USE OF A FULL-ENCIRCLEMENT WELDED SPLIT-SLEEVE

NOTE: *If it is not feasible to take a line out of service and it is not leaking, a full-encirclement welded split sleeve of appropriate design may be used to repair imperfections, damage, or unacceptable welds that cannot be repaired while the line remains in service.*

CAUTION: *Use of full-encirclement welded split sleeves on leaking lines is considered outside the scope of this Standard Practice.*

8.1. Reduce the pipeline pressure to a safe level during the repair operations. To determine the safe operating pressure during repair:

8.1.1. Consider the severity of the defect to be repaired. Consider depth and geometry (i.e., the amount of stress concentration, such as bottomed gouges).

CAUTION: *A severe defect should not be repaired under pressure unless a sound evaluation of the defect has been made by qualified personnel.*

8.1.2. Lower the operating pressure as much as possible, but at least to 67% of the level at time of discovery, or the safe level determined for the particular defect in step 9.1.1. Refer to Standard Practice 2-32-02.

8.1.3. Consult Gas Control before initiating the repair at the safe operating pressure. Consult appropriate supervision if it is not feasible to adequately lower the operating pressure of the pipeline.

8.2. Ensure that the full-encirclement welded split sleeve is of appropriate design. The sleeve must have a design pressure at least equal to the design strength of the pipe being repaired. The sleeve should be at least 12" in width and extend 4 inches beyond the imperfection. The longitudinal welds must be properly prepared for welding.

8.3. Brief personnel on sleeve installation procedures before starting the repair.

8.4. Clean the pipe around the area where the sleeve will be installed. If a dent is repaired, fill the dent with a hardenable filler (e.g. epoxy).

8.5. Move the sleeve to the damaged pipe location and assemble around the pipe. Weld both of the longitudinal seams on the split-sleeve using fillet welds to a side bar in accordance with welding procedures outlined in Standard Practices 2-10-01 and 2-10-02.

CAUTION: *Do not make circumferential end welds on the sleeve.*

8.6. Visually inspect, non-destructively test, and approve the welds made to install a full-encirclement welded split-sleeve following the procedures outlined in Standard Practice 3-15-01.

8.7. Apply pipe coating over the repair and other disturbed areas. Take care to seal the circumferential edges of the sleeve from the soil environment.

8.8. Start up the cathodic protection unit when repairs are completed.

8.9. Complete all records documentation as outlined in section 10 of this Standard Practice.

9. TEMPORARY REPAIR OF A STEEL PIPELINE USING A REPAIR CLAMP

NOTE:	*A damaged steel pipeline that cannot be isolated may be temporarily repaired by placing a clamp of appropriate design over the damaged area.*

9.1. Reduce the pipeline pressure to a safe level during the repair operations. To determine the safe operating pressure during repair.

9.2. Consider the severity of the defect to be repaired. Consider depth and geometry (i.e., the amount of stress concentration, such as sharp bottomed gouges).

CAUTION:	*A severe defect should not be repaired under pressure unless a sound evaluation of the defect has been made by qualified personnel.*

9.2.1. Lower the operating pressure as much as possible, but at least to 67% of the level at time of discovery, or the safe level determined for the particular defect in step 8.1.1. Refer to Standard Practice 2-32-02.

9.2.2. Consult Gas Control before initiating the repair at the safe operating pressure. Consult appropriate supervision if it is not feasible to adequately lower the operating pressure of the pipeline.

9.3. If the pipeline is leaking, ensure all precautions are taken to prevent possible ignition and injury to personnel making repairs to the pipe.

9.4. Select a suitable repair clamp for placement over the damaged area. Consider the size of the damaged area, the maximum allowable operating pressure of the pipeline, the approximate length of time the clamp will be on the pipe, etc. when selecting a clamp.

9.5. Brief personnel that will assemble the clamp around the pipe on clamping procedures before starting the clamping operation.

9.6. Disassemble the clamp at a location away from the damaged pipe location.

9.7. Clean the pipe around the area where clamp will be placed according to the manufacturer's instructions.

9.8. Move the disassembled clamp to the damaged pipe location and assemble around the pipe.

9.9. If the pipeline pressure was reduced, allow pressure to increase. Check clamp for leakage as pipeline pressure is increased. Repair any leaks found on or around the clamp.

9.10. Promptly take any other temporary precautions that may be necessary to protect the public until permanent repairs can be made.

9.11. Start-up cathodic protection unit when repairs are completed.

9.12. Complete all records documentation as outlined in section 10 of this Standard Practice.

10. RECORDS

10.1. Complete a Repair Report (see Figure 1) for each repair made on steel pipelines including the location, date, type of repair, and all other pertinent information.

Note all temporary repairs and record permanent repair information as soon as they are made.

10.2. Forward the completed Repair Report and other applicable information to the Central D.O.T. File.

10.3. Complete and forward Corrosion Detection Report as outlined in Standard Practice 7-35-01.

QUESTAR REGULATED SERVICES COMPANY
PIPELINE REPAIR REPORT

Company ☐ QPC ☐ QGC ☐ QST ☐ Overthrust		DATE	
TYPE OF REPAIR REPORT ☐ Leak ☐ Line Failure ☐ Valve ☐ Right-of-way ☐ Other			
LINE NO. LOCATION			
NOTIFIED BY		DATE	TIME ☐ AM ☐ PM
INJURIES OR FATALITIES			
GAS IGNITED ☐ Yes ☐ No	METALLURGICAL ANALYSIS ☐ Required ☐ Not Required	ESTIMATED COST OF REPAIRS	
CAUSE OF LEAK OR FAILURE ☐ Corrosion ☐ Construction Defect ☐ Material Failure ☐ External Damage ☐ Other:			
EXPLANATION			
TYPE OF COMPONENT INVOLVED ☐ Pipe ☐ Valve ☐ Tap Connection ☐ Meter ☐ Other:			
REPAIR MADE ☐ Band Clamped ☐ Bottom Leak Clamp ☐ Half Sole ☐ Full-Encirclement Split Sleeve ☐ Composite ☐ Other:			

EMERGENCY STOCK USED	LENGTH	SIZE	GRADE	WALL THICK.	IDENTIFICATION	TEST PRESSURE CHART ATTACHED ☐ Yes ☐ No
☐ Pipe ☐ Fitting ☐ Transition Nipple	REMARK					

LINE PRESSURE	TOTAL GAS LOST	VALVE CLOSED (UP) #	VALVE CLOSED (DOWN) #	TIME CLOSED	PIPE SIZE	WALL THICKNESS	GRADE

REPAIRED BY	DATE	SUPERVISORS SIGNATURE	DEPARTMENT OR AREA

REMARKS:

NOTE:	
1. Contact Operations Engineering Department for information to fill out parts of this form. 2. Give location to the nearest mile post, company pole, survey station, etc. 3. Send completed form to Central DOT File. 4. Please attach all applicable information to this report.	SIGNATURE OF INSPECTOR REVIEWED BY

SECTION M GENERAL SAFETY PRACTICES AND PROCEDURES

1. GENERAL SAFETY PRACTICES AND PROCEDURES

1.1. Standard Practices covering safety practices and procedures for the Company will be followed. These standards will contain detailed instructions, procedures and guidelines to be followed in meeting the requirements of this plan.

Reference:	*Standard Practices - Section 8 - Safety*

2. PREVENTION OF ACCIDENTAL IGNITION

2.1. Minimizing Danger.

Appropriate steps will be taken to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion.

Reference:	*Standard Practice 8-20-01, "Confined Space Entry"; Standard Practice 8-20-03, "Hot Work Permit Procedures"*

2.2. Venting Gas Into Open Air.

Each potential source of ignition will be removed from the area whenever a hazardous amount of gas is being vented into open air. Fire extinguishers will be provided and be available in the area of the venting gas.

Reference:	*Standard Practice 2-17-01, "Blowdown Procedures and Temporary Pressure Reduction"*

2.3. Cutting or Welding.

Gas or electric cutting or welding on pipe or pipe components which contain combustible mixtures of gas and air (in the area of the work) will not be permitted.

2.4. Warning Signs.

2.4.1. Ensure warning signs are posted in work areas accessible to pedestrian and vehicular traffic or other work areas where the presence of gas from leakage, purging or venting may constitute a hazard of fire or explosion.

2.4.2. Use appropriate warning devices, signs and/or barricades, as necessary, to route traffic as far away from the work area as practical.

3. PRECAUTIONS IN EXCAVATED TRENCHES: VAPOR/GAS HAZARDS

3.1. Personnel will take adequate precautions when working in excavated trenches to protect from hazards associated with unsafe accumulations of vapor or gas. A Material Safety Data Sheet for natural gas is included at the end of this Section.

3.2. Arrangements will be made for the availability when needed at the excavation for appropriate emergency rescue equipment such as breathing apparatus, rescue harness and line.

Reference:	*Standard Practice 2-17-02, "Excavating and Backfilling"*

4. CUSTOMER NOTIFICATION

4.1. There are no customers downstream of any transmission pipeline facility.

Reference:	*Standard Practice 1-02-01, "Transmission Line Definition"*

5. NATURAL GAS PROPERTIES

Refer to attached Material Safety Data sheets.

Material Safety Data Sheet

May be used to comply with

OSHA's Hazard Communication Standard,

29 CFR 1910.1200. Standard must be

consulted for specific requirements.

U.S. Department of Labor

Occupational Safety and Health Administration

(Non-Mandatory Form)

Form Approved

OMB No. 1218-0072

IDENTITY: **Natural Gas (odorized)**	Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name: **Questar Pipeline Company**	Emergency Telephone Number **800 300-2025**
Address: **180 East 100 South Salt Lake City, Utah 84145**	Telephone Number for Information **801 324-3466**
	Date Prepared **04-30-02**

Section II - Hazard Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other LimitsRecommended	*% (optional)*
Methane	NA	NA	87%	
Ethane	NA	NA		7%
Propane	NA	2500 ppm		2%
Butanes +	NA	800 ppm		1%
Nitrogen	NA	NA	2%	
Carbon Dioxide	5000 ppm	5000 ppm		1%

Section III - Physical/Chemical Characteristics

Boiling Point	- 100	Specific Gravity (H_2O = 1)	NA
Vapor Pressure (mm Hg.)	NA	Melting Point	NA
Vapor Density (AIR = 1)	0.610	Evaporation Rate(Butyl Acetate = 1)	NA
Solubility in Water: 3 x 10-5 lb./lb			
Appearance and Odor: Colorless, odorless, tasteless gas without odorants. Addition of odorants makes leaks detectable at 1/2 to 1% gas in air. Odor is similar to heavy skunk odor.			

Section IV - Fire and Explosion Hazard Data

Flash Point (Method Used): NA	Flammable Limits	LEL5.0%	UEL15.0%
Extinguishing Media: Flame can be extinguished with CO2, Dry chemical, halocarbon gas or water spray.			
Special Fire Fighting Procedures: A hazard of reigniting or explosion exists if flame is extinguished without stopping flow of gas and/or cooling the surroundings and eliminating ignition source. Use water spray to cool surroundings and exposures.			
Unusual Fire and Explosion Hazards: NA			

Section V - Reactivity Data

Stability	Unstable		Conditions to Avoid
	Stable	X	
Incompatibility *(Materials to Avoid)*: Violent or explosive reactions can occur between natural gas and oxidizing agents, such as chlorine, bromine, pentaflouride, oxygen diflouride, and nitorgen diflouride.			
Hazardous Decomposition or Byproducts: Carbon monoxide			
	May Occur		Conditions to Avoid

HazardousPolymerization			
	Will Not Occur	X	

Section VI - Health Hazard Data

Route(s) of Entry:	Inhalation? X	Skin? NA	Ingestion? NA

Health Hazards *(Acute and Chronic)*:

Natural Gas in non-toxic. Natural gas can act as a simple asphyxiant by displacing the oxygen required to support life.

Carcinogenicity:	NTP? NA	IARC Monographs? NA	OSHA Regulated? NA

Signs and Symptoms of Exposure:

Victims of oxygen-deficient atmospheres become cyanotic, experiencing diminished mental alertness and impaired muscular coordination, and dyspnea. Collapse and death can occur at very low oxygen levels.

Medical Conditions Generally Aggravated by Exposure: NA

Emergency and First Aid Procedures: Remove victim to fresh air and restore/support breathing as required.

Section VII - Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled:

Evacuate and clear a safe area. Shut off gas supply. Extinguish all open flames, prohibit smoking, and make certain that electrical switches or other possible ignition sources are not operated. Ventilate enclosed areas by opening doors and windows. Never use a flame to detect leaks.

Waste Disposal Method:

Natural gas is lighter than air and, unless trapped, will rise and dissipate rapidly into the atmosphere.

Precautions to Be taken in Handling and Storing: NA

Other Precautions: NA

Section VIII - Control Measures

Respiratory Protection *(Specify Type)*: Air supplying respirators for emergency or situations where natural gas levels contribute to oxygen deficiency or flammable atmosphere.		
Ventilation	Local Exhaust X	Special
	Mechanical *(General)* X	Other

Protective Gloves: NA	Eye Protection: NA
Other Protective Clothing or Equipment: NA	
Work/Hygienic Practices: NA	

Material Safety Data Sheet

May be used to comply with

OSHA's Hazard Communication Standard,

29 CFR 1910.1200. Standard must be

consulted for specific requirements.

U.S. Department of Labor

Occupational Safety and Health Administration

(Non-Mandatory Form)

Form Approved

OMB No. 1218-0072

IDENTITY: **Natural Gas**	Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name: **Questar Pipeline Company**	Emergency Telephone Number **800 300-2025**
Address: **180 East 100 South** **Salt Lake City, Utah 84145**	Telephone Number for Information **801 324-3466**
	Date Prepared **04-30-02**

Section II - Hazard Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other LimitsRecommended	*% (optional)*
Methane	NA	NA	87%	
Ethane	NA	NA		7%
Propane	NA	2500 ppm		2%
Butanes +	NA	800 ppm		1%
Nitrogen	NA	NA	2%	
Carbon Dioxide	5000 ppm	5000 ppm		1%

Section III - Physical/Chemical Characteristics

Boiling Point	- 100	Specific Gravity (H_2O = 1)	NA
Vapor Pressure (mm Hg.)	NA	Melting Point	NA
Vapor Density (AIR = 1)	0.610	Evaporation Rate(Butyl Acetate = 1)	NA
Solubility in Water: 3 x 10-5 lb./lb			
Appearance and Odor: Colorless, odorless, tasteless gas.			

Section IV - Fire and Explosion Hazard Data

Flash Point (Method Used): NA	Flammable Limits	LEL5.0%	UEL15.0%
Extinguishing Media: Flame can be extinguished with CO2, Dry chemical, halocarbon gas or water spray.			
Special Fire Fighting Procedures: A hazard of reigniting or explosion exists if flame is extinguished without stopping flow of gas and/or cooling the surroundings and eliminating ignition source. Use water spray to cool surroundings and exposures.			
Unusual Fire and Explosion Hazards: NA			

Section V - Reactivity Data

Stability	Unstable		Conditions to Avoid
	Stable	X	
Incompatibility *(Materials to Avoid)*: Violent or explosive reactions can occur between natural gas and oxidizing agents, such as chlorine, bromine, pentaflouride, oxygen diflouride, and nitorgen diflouride.			
Hazardous Decomposition or Byproducts: Carbon monoxide			
HazardousPolyme	May Occur		Conditions to Avoid

rization			
	Will Not Occur	X	

Section VI - Health Hazard Data

Route(s) of Entry:	Inhalation? X	Skin? NA	Ingestion? NA

Health Hazards *(Acute and Chronic)*:

Natural Gas in non-toxic. Natural gas can act as a simple asphyxiant by displacing the oxygen required to support life.

Carcinogenicity:	NTP? NA	IARC Monographs? NA	OSHA Regulated? NA

Signs and Symptoms of Exposure:

Victims of oxygen-deficient atmospheres become cyanotic, experiencing diminished mental alertness and impaired muscular coordination, and dyspnea. Collapse and death can occur at very low oxygen levels.

Medical Conditions Generally Aggravated by Exposure: NA

Emergency and First Aid Procedures: Remove victim to fresh air and restore/support breathing as required.

Section VII - Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled:

Evacuate and clear a safe area. Shut off gas supply. Extinguish all open flames, prohibit smoking, and make certain that electrical switches or other possible ignition sources are not operated. Ventilate enclosed areas by opening doors and windows. Never use a flame to detect leaks.

Waste Disposal Method:

Natural gas is lighter than air and, unless trapped, will rise and dissipate rapidly into the atmosphere.

Precautions to Be taken in Handling and Storing: NA

Other Precautions: NA

Section VIII - Control Measures

Respiratory Protection *(Specify Type)*: Air supplying respirators for emergency or situations where natural gas levels contribute to oxygen deficiency or flammable atmosphere.		
Ventilation	Local Exhaust X	Special
	Mechanical *(General)* X	Other

Protective Gloves: NA	Eye Protection: NA
Other Protective Clothing or Equipment: NA	
Work/Hygienic Practices: NA	

Material Safety Data Sheet

May be used to comply with
OSHA's Hazard Communication Standard,
29 CFR 1910.1200. Standard must be
consulted for specific requirements.

U. S. Department of Labor

Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

IDENTITY: **Natural Gas** (odorized)	Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name: **Questar Southern Trails Pipeline Company**	Emergency Telephone Number: **800 261-0668**
Address: **180 East 100 South** **Salt Lake City, Utah 84145**	Telephone Number for Information: **801 324-3466**
	Date Prepared: **04-30-2002**

Section II – Hazardous Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Names)	OSHA PEL	ACGIH TLV	Other Limits Recommended	%(optional)
Methane	NA	NA		87
Ethane	NA	NA		7
Propane	NA	2500 ppm		2
Butanes+	NA	800 ppm		1
Nitrogen	NA	NA		2
Carbon Dioxide	5000 ppm	5000 ppm		1

Section III – Physical/Chemical Characteristics

Boiling Point	-100	Specific Gravity (H_2O = 1)	NA
Vapor Pressure (mm Hg.)	NA	Melting Point	NA
Vapor Density (Air = 1)	0.610	Evaporation Rate (Butyl Acetate = 1)	NA

Solubility in Water: 3 x 10-5 lb./lb.

Appearance and Odor:
Colorless, odorless, tasteless gas without odorants. Addition of odorants makes leaks detectable at ½ to 1% gas in air. Odor is similar to heavy skunk odor.

Section IV – Fire and Explosion Hazard Data

Flash Point (Methane Used): NA	Flammable Limits	LEL = 5.0%	UEL = 15.0%

Extinguishing Media: Flame can be extinguished with CO_2, dry chemical, halocarbon gas or water spray.

Special Fore Fighting Procedures:
A hazard of reigniting or explosion exists if flame is extinguished without stopping flow of gas and/or cooling the surroundings and eliminating the ignition source. Use water spray to cool surroundings and exposures.

Unusual Fire and Explosion Hazards: NA

Section V – Reactivity Data

Stability	Unstable		Conditions to avoid
	Stable	X	

Incompatibility (Materials to Avoid):
Violent or explosive reactions can occur between natural gas and oxidizing agents, such as chlorine, bromine, pentaflouride, oxygen diflouride, and nitrogen diflouride.

Hazardous Decomposition or Byproducts: Carbon monoxide

Hazardous Polymerization	May Occur		Condition to Avoid
	Will Not Occur	X	

Section VI – Health Hazard Data

Route(s) of Entry:	Inhalation? X	Skin? NA	Ingestion? NA

Health Hazards (Acute and Chronic):
Natural Gas is non-toxic. Natural gas can act as a simple asphyxiant by displacing the oxygen required to support

life.			
Carinogenicity:	NTP? NA	IARC Monographs? NA	OSHA Regulated? NA

Signs and Symptoms of Exposure:
Victims of oxygen-deficient atmospheres become cyanotic, experiencing diminished mental alertness and impaired muscular coordination, and dyspnea. Collapse and death can occur at very low oxygen levels.

Medical Conditions Generally Aggravated by Exposure: NA

Emergency and First Aid Procedures: Remove victim to fresh air and restore/support breathing as required.

Section VII – Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled:
Evacuate and clear a safe area. Shut off gas supply. Extinguish all open flames, prohibit smoking, and make certain that electrical switches or other possible ignition sources are not operated. Ventilate enclosed areas by opening doors and windows. Never use a flame to detect leaks.

Waste Disposal Method:
Natural gas is lighter than air and, unless trapped, will rise and dissipate rapidly into the atmosphere.

Precautions to Be Taken in Handling and Storing: NA

Other Precautions: NA

Section VIII – Control Measures

Respiratory Protection (Specific Type):
Air supplying respirators for emergency or situations where natural gas levels contribute to oxygen deficiency or flammable atmosphere.

Ventilation	Local Exhaust **X**	Special
	Mechanical (General) **X**	Other
Protective Gloves: NA		Eye Protection: NA
Other Protective Clothing or Equipment: NA		
Work/Hygienic Practices: NA		

Material Safety Data Sheet

May be used to comply with
OSHA's Hazard Communication Standard,
29 CFR 1910.1200. Standard must be
consulted for specific requirements.

U. S. Department of Labor

Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

IDENTITY: **Natural Gas**	Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name: **Questar Southern Trails Pipeline Company**	Emergency Telephone Number: **800 261-0668**
Address: **180 East 100 South** **Salt Lake City, Utah 84145**	Telephone Number for Information: **801 324-3466**
	Date Prepared: **04-30-2002**

Section II – Hazardous Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Names)	OSHA PEL	ACGIH TLV	Other Limits Recommended	%(optional)
Methane	NA	NA		87
Ethane	NA	NA		7
Propane	NA	2500 ppm		2
Butanes+	NA	800 ppm		1
Nitrogen	NA	NA		2
Carbon Dioxide	5000 ppm	5000 ppm		1

Section III – Physical/Chemical Characteristics

Boiling Point	-100	Specific Gravity (H_2O = 1)	NA
Vapor Pressure (mm Hg.)	NA	Melting Point	NA
Vapor Density (Air = 1)	0.610	Evaporation Rate (Butyl Acetate = 1)	NA
Solubility in Water: 3 x 10-5 lb./lb.			
Appearance and Odor: Colorless, odorless, tasteless gas.			

Section IV – Fire and Explosion Hazard Data

Flash Point (Methane Used): NA	Flammable Limits	LEL = 5.0%	UEL = 15.0%
Extinguishing Media: Flame can be extinguished with CO_2, dry chemical, halocarbon gas or water spray.			
Special Fore Fighting Procedures: A hazard of reigniting or explosion exists if flame is extinguished without stopping flow of gas and/or cooling the surroundings and eliminating the ignition source. Use water spray to cool surroundings and exposures.			
Unusual Fire and Explosion Hazards: NA			

Section V – Reactivity Data

Stability	Unstable		Conditions to avoid
	Stable	X	
Incompatibility (Materials to Avoid): Violent or explosive reactions can occur between natural gas and oxidizing agents, such as chlorine, bromine, pentaflouride, oxygen diflouride, and nitrogen diflouride.			
Hazardous Decomposition or Byproducts: Carbon monoxide			
Hazardous Polymerization	May Occur		Condition to Avoid
	Will Not Occur	X	

Section VI – Health Hazard Data

Route(s) of Entry:	Inhalation? X	Skin? NA	Ingestion? NA
Health Hazards (Acute and Chronic): Natural Gas is non-toxic. Natural gas can act as a simple asphyxiant by displacing the oxygen required to support life.			

Carinogenicity:	NTP? NA	IARC Monographs? NA	OSHA Regulated? NA
Signs and Symptoms of Exposure: Victims of oxygen-deficient atmospheres become cyanotic, experiencing diminished mental alertness and impaired muscular coordination, and dyspnea. Collapse and death can occur at very low oxygen levels.			
Medical Conditions Generally Aggravated by Exposure: NA			
Emergency and First Aid Procedures: Remove victim to fresh air and restore/support breathing as required.			

Section VII – Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled: Evacuate and clear a safe area. Shut off gas supply. Extinguish all open flames, prohibit smoking, and make certain that electrical switches or other possible ignition sources are not operated. Ventilate enclosed areas by opening doors and windows. Never use a flame to detect leaks.
Waste Disposal Method: Natural gas is lighter than air and, unless trapped, will rise and dissipate rapidly into the atmosphere.
Precautions to Be Taken in Handling and Storing: NA
Other Precautions: NA

Section VIII – Control Measures

Respiratory Protection (Specific Type): Air supplying respirators for emergency or situations where natural gas levels contribute to oxygen deficiency or flammable atmosphere.		
Ventilation	Local Exhaust **X**	Special
	Mechanical (General) **X**	Other
Protective Gloves: NA		Eye Protection: NA
Other Protective Clothing or Equipment: NA		
Work/Hygienic Practices: NA		

Questar Pipeline Standard Practice

7-00-01 GENERAL CORROSION CONTROL PROCEDURES

1. PURPOSE

This Standard Practice outlines the general corrosion control procedures for protecting steel piping systems and facilities. These procedures will be followed by personnel responsible for corrosion control.

2. REFERENCES

2.1. Company DOT Operator Qualification Program.

2.2. Standard Practice 2-17-02, "Excavating and Backfilling."

2.3. Standard Practice 7-10-01, "Designing Cathodic Systems."

2.4. Standard Practice 7-20-01, "Installing Galvanic Anodes for Cathodic Protection of Buried Pipelines."

2.5. Standard Practice 7-20-02, "Installing Cathodic Station Cable Lines."

2.6. Standard Practice 7-20-03, "Installing Cathodic Station Rectifier and Electrical Service-Entrance Equipment."

2.7. Standard Practice 7-20-04, "Installing Cathodic Station Ground Beds."

2.8. Standard Practice 7-20-05, "Installing Electrical Insulators in Distribution Piping Systems."

2.9. Standard Practice 7-30-01, "Taking Pipe-to-Soil Potentials."

2.10. Standard Practice 7-30-02, "Taking Soil Resistivity Measurements."

2.11. Standard Practice 7-35-01, "Inspecting Aboveground and Exposed Portions of Pipelines and Facilities for Corrosion."

2.12. Standard Practice 7-40-01, "Testing For and Correcting Shorted Casings on Cathodically Protected Pipelines."

2.13. Standard Practice 7-50-01, "Correcting Pipe-to-Soil Potentials for IR Drop."

2.14. Standard Practice 7-55-01, "Maintaining Copper-Copper Sulphate Electrodes."

2.15. Standard Practice 7-60-01, "Monitoring Cathodic Protection Rectifier Stations."

2.16. Standard Practice 9-11-01, "Specification for Pipeline Construction for Questar Pipeline, Questar Gas, Questar Southern Trails, Questar Transportation Services."

3. DEFINITIONS - None.

4. SAFETY

No specific instructions required.

5. PERSONNEL QUALIFICATIONS

5.1. Personnel responsible for corrosion control will be directed by an individual qualified in pipeline corrosion control methods and familiar with the procedures outlined herein.

5.2. Personnel responsible for performing covered task(s) outlined herein will be qualified or will be directed and observed by someone who is qualified as outlined in Company DOT Operator Qualification Program.

6. EXTERNAL CORROSION CONTROL - BURIED PIPELINES INSTALLED AFTER JULY 31, 1971

NOTE:	*Temporary pipelines with an operating period of service 5 years or less may not require cathodic protection if public safety is not jeopardized from detrimental corrosion.*

6.1. Each buried pipeline installed after July 31, 1971 will be protected against external corrosion, and include the following:

6.1.1. External coating will meet the requirements outlined in paragraph 9 of this Standard.

6.1.2. Cathodic protection system will be designed and in service to protect the pipeline within 1 year after completion of construction. Refer to Standard Practice 7-10-01.

7. EXTERNAL CORROSION CONTROL - BURIED PIPELINES INSTALLED BEFORE AUGUST 1, 1971

NOTE:	*Buried piping at compressor, regulator, and measuring stations are excluded from requirements of paragraph 7.1.* *For the purpose of this Standard Practice, a pipeline does not have an effective external coating if the current requirements are substantially the same as if it were bare.*

7.1. Buried pipelines installed before August 1, 1971, that have an effective external coating will be cathodically protected along the entire area that is effectively coated.

7.2. The following buried pipelines installed before August 1, 1971 will be cathodically protected in accordance with the procedures outlined herein in areas where active corrosion is found:

NOTE:	*For the purpose of this Standard Practice, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.*

7.2.1. Bare or ineffectively coated transmission pipelines.

7.2.2. Bare or coated pipelines at compressor, regulator, and measuring stations.

7.2.3. Bare or coated distribution lines.

7.2.4. Active corrosion will be determined by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

8. EXTERNAL CORROSION CONTROL: EXAMINATION OF BURIED PIPELINE WHEN EXPOSED

8.1. Exposed portions of buried pipelines will be examined for evidence of external corrosion or coating deterioration. Refer to Standard Practice 7-35-01.

8.2. Remedial action will be taken whenever external corrosion is found as outlined in paragraphs 20, 21, 22.

9. EXTERNAL CORROSION CONTROL: PROTECTIVE COATING

9.1. Pipelines or portions of pipelines that are exposed to the atmosphere must be cleaned and coated with a suitable coating material.

9.2. External protective coatings will have the following characteristics:

9.2.1. Effective electrical isolator.

9.2.2. Effective moisture barrier.

9.2.3. Effective adhesion to the metal surface.

9.2.4. Resistant to damage during handling, storage and installation.

9.2.5. Resistant to disbonding.

9.2.6. Resists chemical degradation.

9.2.7. Easily repaired.

9.2.8. Non-toxic to the environment.

9.2.9. Company approved external protective coatings shall be applied on a properly prepared surface in accordance with Company specifications or other established procedures.

9.3. External protective coating will be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired. Refer to Standard Practice 2-17-02.

9.4. External protective coating will be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

9.5. When coated pipe is installed by boring, driving, or other similar method, precautions will be taken to minimize damage to the coating during installation.

10. EXTERNAL CORROSION CONTROL: CATHODIC PROTECTION

10.1. Each cathodic protection system will provide an effective level of cathodic polarization which can be demonstrated by one or more of the following criteria:

10.1.1. A negative (cathodic) potential of at least 850 mV with cathodic protection applied, measured with respect to a saturated copper/copper sulfate electrode in contact with the electrolyte. Interpretation of such measurements will consider the voltage drop other than those across the structure-to-electrolyte boundary by applying sound engineering methods such as:

a. Measuring or calculating the voltage drop.

b. Evaluating the historical performance of the cathodic protection system.

c. Evaluating the physical and electrical characteristics of the pipe and its environment.

d. Determining whether or not there is physical evidence of corrosion.

10.1.2. A negative (cathodic) polarization potential of at least 850 mV with c.p. interrupted (instant off), measured with respect to a saturated copper/copper sulfate reference electrode.

10.1.3. A minimum of 100 mV of cathodic polarization between the structure and a saturated copper/copper sulfate reference electrode.

11. EXTERNAL CORROSION CONTROL: MONITORING

11.1. Test each pipeline that is under cathodic protection at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements outlined in paragraph 10.

11.2. If tests at intervals outlined in paragraph 11.1 are impractical for testing separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis.

11.2.1. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

11.3. Inspect each cathodic protection rectifier or other impressed current power source six times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating.

11.4. Electrically check each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection and ensure proper performance six times each calendar year, but with intervals not exceeding 2½ months.

11.5. Electrically check other interference bonds at least once each calendar year, but with intervals not exceeding 15 months.

11.6. Prompt remedial action will be taken to correct any deficiencies indicated by the monitoring.

11.6.1. Under normal conditions, evaluation and correction of any deficiencies should begin as soon as practicable and correction completed by the time of the next scheduled monitoring.

11.6.2. Special consideration should be given where required monitoring is less than a year or where deficiencies could result in an immediate hazard to the public.

11.7. Reevaluate unprotected pipelines (at intervals not to exceed three years) and cathodically protect them as outlined herein in areas in which active corrosion is found.

11.7.1. Areas of active corrosion determined by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

12. EXTERNAL CORROSION CONTROL: ELECTRICAL ISOLATION

12.1. Each buried pipeline will be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

12.2. One or more insulating devices will be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

12.3. Each pipeline will be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing. Refer to Standard Practice 7-40-01.

12.4. Inspection and electrical tests will be made to assure that electrical isolation is adequate. This inspection will be done in conjunction with the annual cathodic protection survey once each calendar year not to exceed 15 months.

12.5. An insulating device will not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

12.6. Provide protection against damage due to fault currents or lightning, and at insulating devices where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated.

13. EXTERNAL CORROSION CONTROL: TEST STATIONS

13.1. Each pipeline under cathodic protection required by this Standard Practice will have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

13.2. Test stations should not be installed in vehicular traffic routes, (install in park strips, along fence lines or in similar areas) for corrosion technician safety and to prevent unnecessary interruption of traffic flow.

14. EXTERNAL CORROSION CONTROL: TEST LEADS

14.1. Each test lead wire will be connected to the pipeline so as to remain mechanically secure and electrically conductive. Refer to Standard Practice 7-20-02.

14.2. Each test lead wire will be attached to the pipeline so as to minimize stress concentration on the pipe.

14.3. Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

15. EXTERNAL CORROSION CONTROL: INTERFERENCE CURRENTS

15.1. Pipeline systems subjected to stray currents will have in effect a continuing program to minimize the detrimental effects of such currents.

15.2. Each cathodic protection system will be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. Refer to Standard Practice 7-10-01.

15.3. New steel pipelines should be tested for AC (alternating current) and DC (direct current) interference soon after installation. Refer to Standard Practice 9-11-01. Appropriate remedial measures will be taken to mitigate any detrimental effects from stray electrical currents.

16. INTERNAL CORROSION CONTROL: GENERAL

16.1. Corrosive gas will not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken for appropriate pipeline system design to minimize internal corrosion.

16.2. Gas which does not meet the quality stardard set forth in the tarif may or may not be corrosive to the pipeline; however, out of spec gas will be dealt with per section V, paragraph 3.7 of the Company Emergency Plan.

NOTE:	*Gas containing free water at pipeline conditions shall be considered corrosive unless proven to be noncorrosive by recognized tests or experience.*

16.2 Whenever any pipe is removed from a pipeline for any reason, the internal surface will be inspected for evidence of corrosion, and reported on a Field Activity Report or Corrosion Detection Report.

16.3 If internal corrosion is found:

16.2.1. Adjacent pipe will be investigated to determine the extent of internal corrosion;

16.2.2. Replacement will be made to the extent required by the applicable paragraphs of [§§ 192.485 or 192.487]; and

16.2.3. Upon investigation of the cause of such corrosion, appropriate pipeline system design modifications or changes in operating parameters will be made to minimize the internal corrosion.

17. INTERNAL CORROSION CONTROL: MONITORING

When corrosive gas is being transported, coupons or other suitable means will be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion will be checked two times each calendar year, but with intervals not exceeding 7½ months.

18. ATMOSPHERIC CORROSION CONTROL: GENERAL

Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere will be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. Refer to Standard Practice 7-35-01.

19. ATMOSPHERIC CORROSION CONTROL: MONITORING

Reevaluate once every three calendar years (not to exceed 39 months) each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

20. REMEDIAL MEASURES: GENERAL

20.1. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion will have a properly prepared surface and will be provided with an external protective coating that meets the requirements outlined in paragraph 9 of this procedure.

20.2. Each segment of metallic pipe that replaces pipe removed from a buried pipeline because of external corrosion will be cathodically protected in accordance with this Standard Practice.

21. REMEDIAL MEASURES: TRANSMISSION LINES

21.1. General corrosion:

Each segment of transmission line with general corrosion (with a failure pressure as determined by the procedure in paragraph 21.3, less then the maximum allowable operating pressure of the pipeline) will be repaired, replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

21.2. Localized corrosion pitting:

Each segment of transmission line pipe with localized corrosion pitting to a depth with a failure pressure, as determined by the procedure in paragraph 21.3, less than that required for the maximum allowable operating pressure of the pipeline will be replaced or repaired, or the operating pressure will be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

21.3. Under paragraphs 21.1 and 21.2 of this procedure, the failure pressure of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G, the procedure in AGA Pipeline Research Committee Project PR 3-805 (RSTRENG) or Kiefner and Associate, Inc. Pipe Assessment (KARA) assessment software. Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

22. REMEDIAL MEASURES: DISTRIBUTION LINES

22.1. General corrosion:

Each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, will be repaired or replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

22.2. Localized corrosion pitting:

Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result will be replaced or repaired.

23. CORROSION CONTROL RECORDS

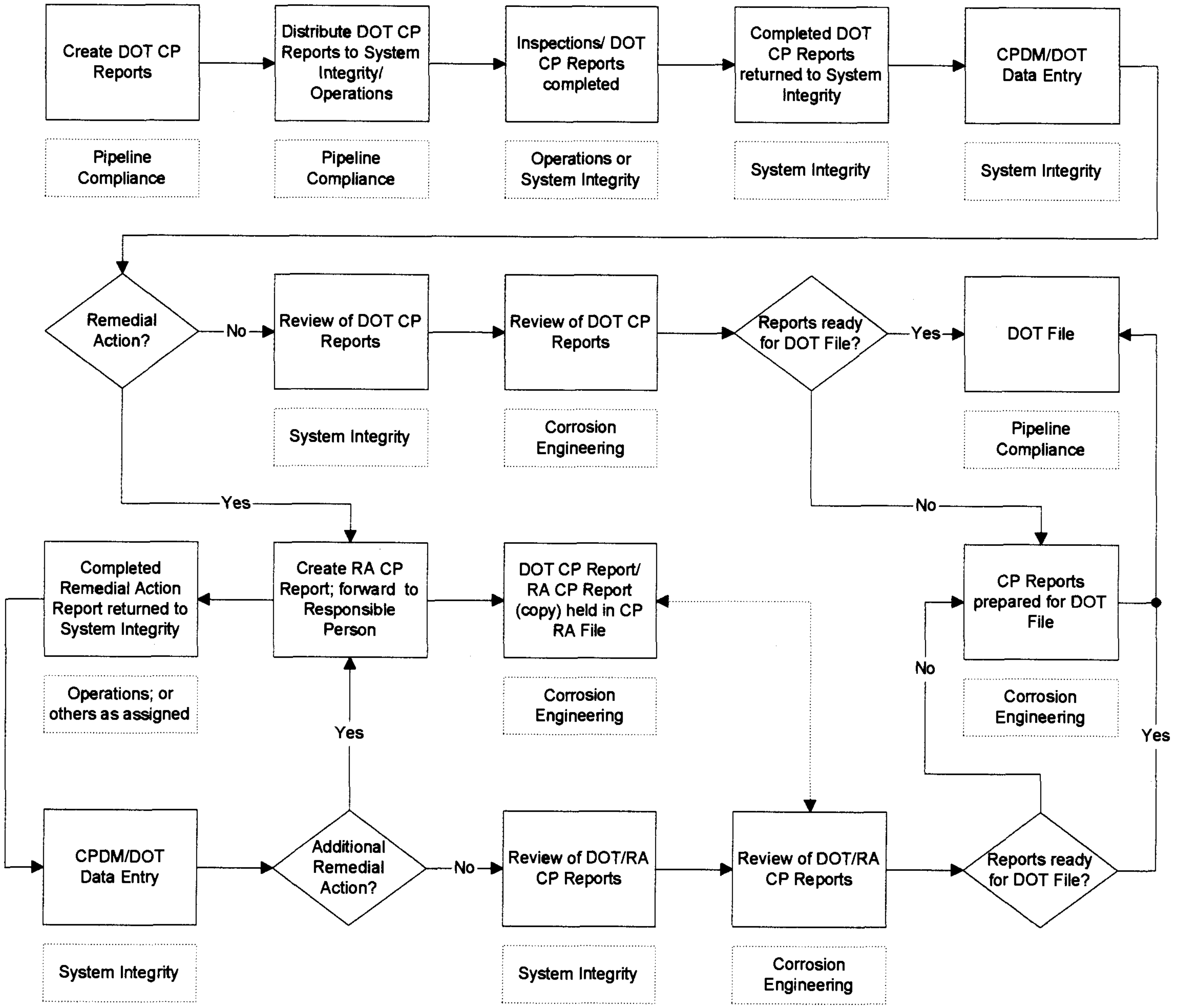
23.1. Records or maps will be maintained to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

23.2. Each record or map required by paragraph 23.1 of this procedure will be retained for as long as the pipeline remains in service.

23.3. Records will be maintained of each test, survey, or inspection required by this Standard Practice in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records will be retained for at least 5 years, except that records related to §§ 192. 465(a) and (e) and 192.475(b) will be retained for as long as the pipeline remains in service.

23.4. The work flow process for DOT-required cathodic protection inspection records shall be as shown in Figure 1. DOT-required records shall be reviewed by Corrosion Engineering to ensure adequacy of corrosion protection.

Work Flow Process
Cathodic Protection DOT Records



Terms:

CPDM - Cathodic Protection Data Management
RA - Remedial Action
CP - Cathodic Protection

Cathodic Protection Records include:

1. Annual P/S survey
2. Bond Inspections
3. Rectifier Inspections

NOTE: All hard copy DOT CP records in DOT file will include information to demonstrate adequate CP protection.

SECTION 6: HANDLING AND EVALUATING EMERGENCY CALLS

1. RECEIVING EMERGENCY CALLS

1.1. During normal business hours (7:00 am MST - 6:00 pm MST), emergency calls will normally be received by the Rock Springs Operations Center. In the event other departments receive the emergency calls, the calls will be transferred or the appropriate information relayed to the Rock Springs Operations Center and/or Gas Control.

1.2. During evening hours (6:00 pm MST- 7:00 am MST), weekends and holidays, emergency calls will be received by the Gas Control Department. In the event other departments receive the emergency calls, the calls will be transferred or the appropriate information relayed to Gas Control.

1.3. The initial status of the emergency will be determined as quickly as possible. It must be recognized that during early stages of emergency conditions, information which is available will be very limited and possibly misleading. Every effort will be made to obtain and document information as completely and correctly as possible.

2. INFORMATION TO BE OBTAINED

2.1. The following will serve as a guideline to define the type of information needed for an initial status evaluation of an emergency (descending order of importance).

2.1.1. Location of emergency

2.1.2. Time of call

2.1.3. Name of person calling (first and last), their location and phone number, whether they face any imminent danger

2.1.4. Number of those injured

2.1.5. Have the injured been cared for and where have they been taken

2.1.6. Verify if 911 has been called; others who have been notified

2.1.7. Persons at the scene: Police, Fire Department, Company employees and any witnesses

2.1.8. Are there any immediate potential hazards

2.1.9. Apparent cause of the emergency

2.1.10. Description of emergency

2.1.11. What type of equipment is involved (pipe size and valve(s), etc.)

2.1.12. Extent of damage

2.1.13. Damaging party, if applicable

2.1.14. Actions which have been taken

3. INSTRUCTIONS GIVEN TO CALLERS

3.1. After evaluating initial status of the emergency, consider giving any or all of the following instructions to callers to minimize the exposure to any potential hazardous conditions.

3.1.1. Stay clear of hazard

3.1.2. Avoid open flames and sparks

3.1.3. Avoid using or operating telephones, electrical switches, electrical tools and machinery that could ignite hazardous gas-air mixtures (e.g. do not turn lights on or off; unplug electrical appliances)

3.1.4. Avoid excessive breathing of natural gas

3.1.5. Evacuate the hazardous area

3.1.6. Notify fire department immediately, if fire is involved

3.1.7. Block off area

3.1.8. Care for the injured

3.1.9. Report that repair crews and/or local emergency responders will be or have been dispatched

4. EVALUATING THE EMERGENCY

4.1. Evaluate the emergency conditions before any action is taken.

4.2. Consider the following points when evaluating emergency conditions.

4.2.1. Analysis of known facts

4.2.2. Procurement of additional facts

4.2.3. Recognition of immediate and potential hazards

4.2.4. Analysis of safety factors

4.2.5. Determination of involvement of emergency response official/agencies

4.2.6. Determination of equipment required

4.2.7. Determination of personnel required

4.2.8. Determination of action required, including shutdown, isolation and blowdown of pipeline facilities

5. NOTIFYING SUPERVISION AND DISPATCHING EMPLOYEES

5.1. Informing appropriate Supervision.

5.1.1. As soon as possible after obtaining the initial status of the emergency, Rock Springs Operation Center and/or Gas Control will notify the appropriate supervision (refer to Emergency Plan Section 15 for Emergency Contact List).

5.1.2. Give all facts as they are known at the time.

5.2. Initiating emergency action for events requiring an immediate response by the company.

5.2.1. Action should be immediately initiated after the emergency condition has been evaluated and the course of action determined, including shutdown, isolation and blowdown of pipeline facilities. Refer to Section 8 of this plan for a detailed listing of system emergencies.

5.2.2. Guidelines and major considerations for initiating the actions are as follows.

a. Mobilize and dispatch all necessary personnel, equipment and materials

b. Establish necessary liaison and communication with appropriate public officials

Reference: Community Emergency Preplanning and Liaison Contingency Plans (where established with local communities refer to Emergency Plan Section 10, "Liaison with Appropriate Public Officials")

c. Monitor the system and maintain a status record and log of events

d. Establish effective control and follow-up procedures

e. Keep Supervision informed of action taken

SECTION 8: CONTROLLING EMERGENCY SITUATIONS

1. PRIORITIES OF EMERGENCY ACTION

Emergency action will be established on a priority basis. High priority level action will always take precedence over lower level priority action. The priority of any emergency action will be evaluated from the following decreasing priority level sequence.

NOTE:	*All employees are expected to understand this list of priorities and to use this as a guide in all emergency situations.*

1.1. Customer and general public safety.

1.2. Employee safety.

1.3. Protecting Property.

1.4. Environmental Concerns.

1.5. Customer inconvenience.

1.6. Public relations.

1.7. Economic considerations.

2. EMERGENCY ACTION CONSIDERATIONS

The first Company personnel at the scene will determine the existing hazards. The following measures will be considered and taken as necessary to minimize hazards.

NOTE:	*In certain situations, local emergency response officials may be the first responders on scene and may have initiated one or more of these actions.*

2.1. Evacuate premises which are or may be affected.

2.2. Request notification to and/or assistance from appropriate fire, police or other public officials (e.g. 911).

2.3. Block off potentially hazardous areas and reroute traffic if necessary.

2.4. Prevent accidental ignition.

2.5. Determine the full extent to the hazardous area, including the discovery of any gas migration in or around nearby buildings, sewers or other structures, and the possibility of multiple leaks as a result of the initial damage.

2.6. Report details of the emergency to appropriate supervision and to Gas Control where appropriate. Request further instructions or assistance if needed.

NOTE:	*In the event evacuations are necessary in advance of arrival of emergency response officials, Company employees will notify the affected public of the need to evacuate.*

2.7. In coordination with Gas Control, control the flow of leaking gas by section isolation, pressure reduction or other appropriate means.

2.8. Ventilate affected premises.

2.9. Provide follow-up reporting to supervision and Gas Control.

2.10. Restore service outage when safe to do so.

3. SYSTEM EMERGENCIES REQUIRING AN IMMEDIATE RESPONSE

3.1. Escaping gas.

3.1.1. An incident where any pipe, valve, or related equipment carrying natural gas, which has been damaged to the extent that gas is escaping, will be treated and classified as an emergency condition.

3.1.2. The initial action to be taken will be to stop the flow of escaping gas at the point of damage. Depending upon the nature and extent of the incident, this can be accomplished by one or more of the following methods.

a. Installation of a suitable leak clamp

b. Tightening and/or greasing any leaking valves or fittings

c. Stopping the flow of gas by isolating the damaged facility

3.1.3. Consider installation of a bypass whenever the shutdown will be extensive.

3.2. Fires.

3.2.1. An incident where a fire has been reported in any Company building, pipeline or pipeline facility will be treated and classified as an emergency condition.

3.2.2. The initial action to be taken when a fire has been reported is to coordinate and/or assist with the appropriate fire department insofar as the emergency affects the gas piping or facilities.

3.2.3. Fires in buildings

The first priority action of a fire in a building will be to shut off the gas supply to the building. This can be accomplished by closing the inlet valves and/or isolating the area.

3.2.4. Fires in natural gas piping

a. The first priority action in such an incident will be to immediately institute the appropriate measures required to stop the flow of gas and the appropriate measures required to protect the surrounding area from the consequences of the fire.

b. The decision to extinguish the fire before the escaping gas has been stopped will be made on the basis of the following considerations.

i. The hazard involved to the surrounding area if the fire continues to burn

ii. The potential explosion hazard if the fire is extinguished

iii. The potential hazards of re-ignition if the fire is extinguished

3.2.5. Fires in or near natural gas pipeline facilities

a. Incidents where gas has ignited within or in the vicinity of a natural gas pipeline facility require an immediate evaluation as to the action necessary to protect the pipeline system supplied from that facility. The following factors should be considered.

   i. Status and function of natural gas pipeline facility

   ii. Potential hazard of over or under pressure within the system

   iii. Potential hazard of rupture to piping or station equipment

   iv. Consequences involved if facility is removed from service

   v. Consider installation of bypass piping

b. After evaluation of the condition is complete, appropriate action will be taken.

3.3. Explosions.

3.3.1. Explosions in buildings will be treated and classified as an emergency condition.

a. The priority action to be taken where an explosion has occurred in any structure to which natural gas is supplied is to shut off the supply of gas to the building. This action is to be initiated regardless of the cause of the explosion.

b. After the gas has been shut off, precautions will be taken to prevent additional explosions and a leak survey investigation will be made in the area to determine the possible source of the explosion.

3.3.2. Explosions in or near a natural gas piping system will be treated and classified as an emergency condition.

The initial action to be taken where an explosion has occurred within or in the immediate vicinity of a natural gas piping system, and where the system has been damaged, is to stop the escape of gas from the damaged area.

3.3.3. Explosion in or near natural gas pipeline facilities will be treated and classified as an emergency condition.

The primary action to be taken when an explosion has occurred within or in the immediate vicinity of a natural gas pipeline facility, and where the facility has been damaged, is to stop the escape of gas from the damaged area.

3.4. Abnormal pressure will be treated and classified as an emergency condition.

3.4.1. High pressure conditions

When the pressure within a natural gas system exceeds the pre-established maximum allowable operating pressure (MAOP), immediate steps will be taken to determine the cause and reduce the pressure to an acceptable limit. The following system conditions will be immediately inspected and corrective action taken where necessary.

a. Damage to or improper operation of metering, pressure limiting or regulator equipment, control lines or pressure set points

b. Damage to or improperly operated system bypass valves or crossover valves

c. Closed or partially closed system valves

3.4.2. Immediate action will also be taken to reduce the high pressure condition within the system to an acceptable range by operating relief valves or opening blow-down valves to the atmosphere.

3.5. Low pressure will be treated and classified as an emergency condition.

3.5.1. When the system or segment of the systems operating pressure is reduced below the acceptable pressure, immediate steps must be taken to improve the condition. The following conditions will be immediately checked and the appropriate corrective measures taken.

a. Malfunction within metering, pressure limiting or regulator stations

b. Obstructions within piping system

c. Closed or partially closed system valves

d. Line damage

e. System capacity problems

3.5.2. Immediate action will also be taken to restore the system to the proper operating pressure.

3.6. Gas within or in the vicinity of buildings will be treated and classified as an emergency condition.

Whenever an indication of natural gas has been found within or against the foundation (within 10 feet, 20 feet during the winter frost season) of a building or any gas registering a stable reading on a combustible gas indicator (approximately 2% gas in air or more) is detected within a duct system, such as a sewer, telephone, storm drain or power, the following action will be immediately taken.

NOTE: *If less than 2% gas in air is detected within such a duct system, monitor the situation closely until a leak is found and repaired or verification is made that no leak exists.*

3.6.1. Evacuate building(s)

3.6.2. Eliminate potential sources of ignition that are in the immediate area

3.6.3. Check all gas equipment and piping for leaks and defects. If leaks or defective equipment are found, corrective action will be taken.

3.6.4. Initiate a leak survey of the immediate area and surrounding structures to determine if there are any leaks in the underground piping system.

3.6.5. Ventilation to the atmosphere of inside areas, which are found to contain natural gas. Ground areas containing natural gas will be ventilated by excavating holes at suitable locations.

3.7. Abnormal quality of gas <u>will be treated and classified as an emergency condition.</u>

The gas received by Questar from shipper and delivered by Questar to shipper shall conform to the following specifications:

3.7.1. Heat Content: The gas delivered at each of the points of receipt and delivery shall contain a gross heating value of not less than 950 Btu per cubic foot not more than 1150 Btu per cubic foot.

NOTE:	*Tariff provisions for QST are, not less than 980 Btu per cubic foot not more than 1150 Btu per cubic foot.*

3.7.2. When the BTU value within the system or segment of the system is above or below the pre-estimated limits, immediate action must be taken. Consider any or all of the following.

a. Isolate the system or segment of the system

b. Blend with other gas to achieve desired BTU level

c. Divert the gas to another area

d. Blow down and/or purge

e. Use the gas, as is, depending on the conditions

3.7.3. Hydrogen Sulfide: The gas shall not contain more than ¼ grain of hydrogen sulfide per 100 cubic feet.

3.7.4. When the hydrogen sulfide content within the system segment of the system exceeds the predetermined maximum allowable limits, immediate action must be taken. Consider any or all of the following.

a. Follow procedures outlined in Standard Practice Section 8-45-01 if applicable

b. Blend with other gas to reduce H_2S content to acceptable level for pipeline specifications

c. Isolate the system or segment of the system

d. Divert the gas to another area

e. Burn vented gas that was blown down or purged

f. Blow down and/or purge

3.7.5. Inert Substances: The gas shall not contain inert substances in excess of three percent by volume. Of which CO_2 may not exceed two percent by volume.

3.7.6. When the inert content of the gas within the system or segment of the system exceeds the predetermined maximum limits, immediate action must be taken. Consider any or all of the following.

a. Isolate segment of system for future blending of gas

b. Divert the gas to another area for future blending

c. Shut-in source(s) of high inert gas

d. Blow down as last resort

3.7.7. Liquids: Gas tendered for transportation at a receipt point shall not contain any free liquids of any nature and shall conform to the CHDP specification set forth in paragraph 13.2 and 13.3 of the QPC Tariff, which reads as follows:

a. Cricondentherm Hydrocarbon Dew Point (CHDP).

i. CHDP Limit - Questar will accept all deliveries of natural gas within CHDP Zones 1 through 9 at a CHDP equal to or less than 35° Fahrenheit and equal to or less than 15° Fahrenheit within CHDP Zone 10, provided that such gas satisfies all other applicable provisions of Questar's FERC Gas Tariff.

ii. CHDP Operating Limit - Questar may, from time to time, as operationally feasible, establish and post on its internet web site a CHDP Operating Limit that is higher than the CHDP Limit for natural gas received into its system on specified CHDP Zones. Questar's ability to establish and post higher CHDP Operating Limits for particular zones will depend on pipeline operating characteristics such as pressures and temperatures, blending capability of prevailing and expected gas supplies and proximity to downstream city gates and interconnecting pipelines as well as the existence of processing and liquids handling facilities within a CHDP Zone.

iii. Questar shall not be obligated to accept gas into its system that exceeds the applicable CHDP limit. The existence of a CHDP limit shall not be deemed to negate, reduce or limit Questar's authority to issue operational flow orders. To the extent operationally practicable, Questar may waive a CHDP limit for gas received from certain points on its system provided such waiver is made on a non-discriminatory basis.

iv. When operationally feasible, Questar will exempt low-volume sources from the CHDP Operating Limit on a non-discriminatory basis and accept gas into its system that exceeds the posted CHDP Operating Limits. Questar will post a system-wide minimum flowing volume that will establish the CHDP Limit exemption threshold for small producing sources from individual MAP points. Single sources with volumes of less than 100 Dth/d will generally be exempt from the proposed CHDP Limits. However, whenever multiple low-volume sources converge to cause Questar problems in meeting downstream CHDP requirements, Questar may elect to temporarily suspend the minimum volume exemption on localized portions of its system until the downstream CHDP problems are resolved.

b. CHDP Operating Limit Posting Procedure:

i. Questar may post a CHDP Operating Limit at or above the CHDP Limit for each CHDP zone. The posted CHDP Operating Limit will apply to all receipt points within the CHDP zone. Questar will provide as much prior notice of changes to its CHDP Operating Limits as possible and attempt to provide at least two day's notice prior to the timely cycle nomination deadline. However, Questar may reduce the CHDP Operating Limit to the CHDP Limit at any time without notice, when operationally necessary. In such event, Questar will post a critical notice on its Internet web site.

ii. For receipt points with online chromatographs, Questar shall post on its internet web site the prior gas day average and maximum calculated CHDP at each receipt point. For receipt points without online chromatographs, once per month Questar shall post on its internet web site the average and maximum calculated CHDP at each receipt point for the prior month period. Compliance with CHDP limits will be determined based on calculated current flowing CHDP temperatures.

3.7.8. Merchantability: The gas shall be commercially free form dust, gums, and gum-forming constituents, dirt, impurities or other solid or liquid matter that might interfere with its merchantability or cause injury to or interference with proper operation of the pipelines, regulators, meters, or other equipment of Questar. The gas shall also be free of all matter that is deemed hazardous or toxic and is subject to regulation by the Environmental Protection Agency or any State_agency having similar jurisdiction or authority.

3.7.9. Oxygen: The gas shall not have an oxygen content in excess of 10 parts per million by volume, and the parties shall make every reasonable effort to keep the gas free of oxygen.

3.7.10. Temperature: The gas shall be delivered at a temperature not in excess of 120 degrees Fahrenheit or less than 35 degrees Fahrenheit at any receipt or delivery point.

3.7.11. Total Sulfur: The gas shall not contain more than 5 grains of total sulfur per Mcf, of which not more than 2 grains shall be mercaptan sulfur.

3.7.12. Water Vapor: The gas shall not contain in excess of 5 pounds of water per million cubic feet.

When the water content within the system or segment of the system is above the pre-estimated limits, immediate action must be taken. Consider any or all of the following.

a. Isolate the system or segment of the system

b. Blend with other gas to reduce water content to acceptable level for pipeline specifications

c. Blow down and/or purge

d. Pig the line

e. Use of line heaters

f. Use of dehydrator units

g. Use of methanol in the line

h. Additional stages of regulation

i. Monitor line and take dew point readings

NOTE:	*Tariff provisions for QST: Water vapor: Gas shall not contain in excess of 7 pounds of water per million cubic feet.*

4. CIVIL DISTURBANCES

Damage to Company facilities may or may not exist during a civil disturbance; therefore, the problem becomes one of protection and maintenance of Company facilities. Safety to general public and employees will be foremost in maintaining Company facilities during a civil disturbance.

4.1. The Company will become involved only in those actions which are required as follows.

4.1.1. Solicit protection for its facilities

4.1.2. Maintain the facilities

4.1.3. Protect the public from the consequences of damage to its facilities

4.1.4. Protect its employees from the consequences of the disturbance

4.2. The following actions will be taken by Company employees during a civil disturbance.

4.2.1. Employees will report to specific duty stations as requested or otherwise assigned

4.2.2. Employees will not enter a riot area or an area of civil disturbance alone

4.2.3. Police protection will be solicited for employees entering an area of civil disturbance

4.2.4. Employees will make every effort to avoid any involvement with riot or civil disturbance participants

4.3. Management will evaluate the system to determine areas or points in the system, which could be affected by the disturbance. Particular emphasis will be given to the following.

4.3.1. Metering, pressure limiting or regulator stations

4.3.2. Valves and valve assemblies

4.3.3. Company office buildings

4.3.4. Vehicle storage areas

4.3.5. Compressor stations

4.3.6. Gas Control

4.3.7. Exposed piping

4.3.8. Other pipeline facilities

4.4. After evaluating the impact of the disturbance on the system, recommendations will be developed on actions, which would be required to adequately protect the critical areas or facilities. These would include, but not be limited to, the following actions.

4.4.1. Installation of security devices such as barricades, locks, or lights

4.4.2. Erection or installation of physical barriers (barricading, trenching, fencing, vehicles or equipment)

4.4.3. Assignment of company personnel to patrol the area

4.4.4. Requests to law enforcement agencies for police protection

4.4.5. Request to National Guard authorities for protection assistance

4.5. After the condition has been analyzed and proposed action established.

4.5.1. Coordinate and verify proposed action with appropriate supervision

4.5.2. Initiate required actions

4.5.3. Establish control and communications with all necessary personnel

4.5.4. Establish a record and status report of action being taken

4.5.5. Keep supervision informed

5. OTHER MAJOR/NATURAL DISASTERS

Damage to Company facilities will vary depending upon the magnitude of the disaster; therefore, the first action will be to assess the nature and extent of damage and establish communication with chain of command.

5.1. Advanced planning.

5.1.1. Employees are assigned to report to a specific duty station in case of a major disaster. This station is usually, but need not be, the regular assigned duty position.

5.1.2. Law enforcement departments, fire department, public authorities, and the National Guard are to be kept informed of Company's proceedings by employees designated as liaison agents.

5.1.3. Command posts will be designated as follows.

a. Gas Control – Questar Building, Salt Lake

b. Questar Pipeline Office – Rock Springs

c. Emergency site

5.2. Earthquake notification.

5.2.1. The National Earthquake Information Center (NEIC) will notify Gas Control, by fax, of any earthquakes with a magnitude of 4.0 or greater in the Intermountain Area. This notification should be received 30 to 90 minutes following the event. This information should be recorded on a permanent log and the call list should be initiated. NEIC will provide the following.

a. Date and time of earthquake

b. Richter magnitude

c. Epicenter Location

d. Preliminary reports of damage caused by earthquake

e. Preliminary casualty report

5.2.2. The University of Utah Seismograph Stations (UUSS) will notify Gas Control, by fax, of any earthquakes with a magnitude of 3.0 or greater in Utah and the area currently served by Questar in Wyoming. This notification should be received 30 to 90 minutes following the event. This information should be recorded on a permanent log and the call list should be initiated. UUSS will provide the following.

a. Date and time of earthquake

b. Richter magnitude

c. Epicenter Location

d. Any other pertinent information they possess

5.2.3. Questar Pipeline Operations Supervisors or their designated alternates will notify the Gas Control whenever they "feel" an earthquake. Notification should be received from Operations Supervisors within minutes of the event. This information should be recorded on a permanent log and the call list should be initiated. Operations Supervisors should provide the following.

a. Date and time of earthquake

b. Relative strength of ground motion

c. If a "roaring" sound was produced by the earthquake

d. Whether damage to buildings or the gas system might be expected

5.3. Initial action.

5.3.1. All employees will report to pre-assigned duty stations as soon as possible.

5.3.2. All employees assigned liaison functions will report to liaison area as soon as possible.

5.3.3. Command posts will establish communication with central command and all liaison areas.

5.3.4. Personnel and equipment will be dispatched by command post and to damaged facilities to assess and evaluate the extent of the damage and make repairs.

5.4. Additional actions.

5.4.1. A full damage assessment will be completed in all impacted and adjacent areas experiencing ground movement of shaking, including a detailed visual inspection of all pipelines, tap lines, valve installations, pressure limiting or regulator stations, compressor stations and cathodic protection rectifiers.

5.4.2. Promptly complete a thorough instrumented leak detection survey of all buried pipelines in affected areas.

5.4.3. Consider the need for additional analysis or review of the piping system to detect damage to buried pipeline, including use of internal inspection devices.

5.5. Reporting to command post.

After making an evaluation of the emergency, (refer to paragraph 5.4).forward all the following information to command post.

5.5.1. Damaged facilities

5.5.2. Fires

5.5.3. Service areas lost

5.5.4. Action already taken by Operations and Emergency personnel

5.5.5. Proposed plan of action

5.5.6. Reports from liaison areas

5.5.7. Available assistance

5.5.8. Other pertinent information

5.6. Repair and restoration of damaged facilities.

5.6.1. All damaged, leaking or failed components will be repaired. The priority of repair work will be coordinated through Central Command post, or through normal supervisory channels, as appropriate.

5.6.2. For additional information on proper repair methods, refer to Section B of Questar Pipeline Performance Standards and applicable company Standard Practices.

5.6.3. Restoring service outages will only be done when it is safe to do so following and emergency. Refer to Emergency Plan Section 9 "Restoration of Service."

5.7. Post-Event assessment.

The Company will complete a follow-up review of employee activities during the emergency response. Refer to Emergency Plan Sections 1 "Introduction" and 4 "Employee Training" for more information on post incident evaluation.

SECTION 9: RESTORATION OF SERVICE

1. RESTORATION OF TRANSMISSION LINES AND FACILITIES

1.1. In the event of an incident, restoration will be in coordination with local authorities and DOT.

1.2. As soon as required repairs have been made, and damaged pipelines and/or pipeline facilities have been rendered safe, the following action will be taken.

1.2.1. Obtain restoration clearance from appropriate supervision.

1.2.2. Identify all critical valve locations, regulator stations and blowoff or purge locations (via maps or lists).

1.2.3. Identify all customers who may be affected by restoration of service and establish appropriate control methods to ensure safe operation after restoration.

1.2.4. Establish and prepare required purging points.

NOTE:	*Notify authorities when purging to the atmosphere.*

1.2.5. Introduce gas into and purge all pipelines and/or pipeline facilities free of possible air entrapment. Refer to Standard Practice 2-17-03 "Purging Pipelines."

1.2.6. Restore pressure in pipelines and/or pipeline facilities and restore area to normal operation.

1.2.7. Perform a leak survey when required to identify any additional leaks.

SECTION 5: ASSIGNMENT OF RESPONSIBILITIES

1. RESPONSIBILITY FOR OVERALL COORDINATION AND EMERGENCY OPERATIONS.

1.1. Chain of Command.

1.1.1. The chain of command during an emergency condition is the same as the organizational structure of the Company. However, during the early stages of an emergency, the responsibility often rests with those employees first arriving at the emergency site.

1.1.2. Management may also establish additional chains of command. These additional chains of command could include the following.

a. Local Emergency responders, including entities where community liaison plans are in effect (refer to Emergency Plan Section 10, "Liaison with Appropriate Public Officials").

b. Personnel assigned to a specific company function such as communications, Gas Control, metering and pressure limiting or regulator stations, pipeline inspection, engineering, safety etc.

c. Personnel assigned to specific company locations or areas

d. Personnel assigned from an outside function or area such as the operation of company facilities by other company or contracted personnel.

1.1.3. Supplemental or replacement chains of command can be established by management at any time prior to or during an emergency condition. This action is usually taken whenever reinforcement or increased expertise in the command area is needed.

1.2. Command Posts.

1.2.1. Command Posts will be established at one or more of the following locations as required by the status, condition and degree of the emergency:

a. Emergency site

b. Gas Control

c. Management office

d. Field offices

e. As designated by management

2. DEPARTMENTAL RESPONSIBILITIES

2.1. Gas Control Department.

2.1.1. The Gas Control Department will be responsible for the following as required by the conditions of the emergency.

a. Receive emergency calls for pipeline operations

b. Give safety instructions to callers

c. Dispatch operational personnel and notify supervision and management

d. Inform General Manager of progress being made on repairs

e. Notify fire, police or other public officials

f. Notify Environmental and Safety Services, Security, Legal, Pipeline Compliance and Corporate Communications

g. Monitor and maintain communications

h. Maintain a log of events

i. Monitor pipelines

j. Monitor compressor and pressure limiting or regulator stations

k. Coordinate with repair crews

l. Inform Management of gas supply developments

m. Complete necessary Gas Loss Reports as assigned

2.2. Vice President of Operations and Gas Control.

2.2.1. The Vice President of Operations and Gas Control will be responsible for the following as required by the conditions of the emergency.

a. Inform management of extent of damage

b. Recruit necessary manpower, equipment and material needed to accommodate the needs of the situation

c. Coordinate repair crews

d. Address reporting of emergency information to agencies (refer to Emergency Plan Section 7, "Obtaining and Reporting Emergency Information")

NOTE:	*In the event the Vice President of Operations and Gas control is not available, these responsibilities will be assigned by highest level of supervision available or the on-call supervisor.*

2.3. Engineering.

Engineering will support crews and appropriate public officials as necessary with descriptions of line and valve locations, maps and records.

2.4. Incident Investigation Team.

2.4.1. Pipeline accidents and system failures should be investigated as soon as possible after an emergency.

NOTE:	*The DOT on-call representative will be responsible to notify the Incident Investigation Chair Person (Manager of Operation Support) whenever it is determined that the Incident Investigation Team should be activated. In the event the Operation Support Manager is not available, management will be consulted and an acting Incident Investigation Chair will be appointed.*

2.4.2. Under the direction of the Incident Investigation Chair Person, investigate emergency situations.

2.4.3. When the team is activated, all field activities should be coordinated through this team prior to disturbing or removing equipment or material involved.

2.4.4. Complete reports as outlined in Standard Practice 8-18-01

2.5. Others Departments.

Under the direction of Management, other departments may be called to assist in emergency situations.

Questar Standard Practice

8-18-01 PIPELINE ACCIDENT AND FAILURE INVESTIGATION

1. PURPOSE

This Standard Practice describes the general procedures to be observed by a local investigation team or the Pipeline Accident Investigation Team when investigating a pipeline accident or failure as soon as possible after the emergency. The purpose of such investigation will be to determine the root cause of the failure, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, and to minimize the possibility of a recurrence.

2. REFERENCES

2.1. Applicable Company Emergency Plan.

2.2. Written Company DOT Operator Qualification (OQ) Plan.

2.3. Standard Practice 8-10-00, "Personal Protective Equipment."

3. DEFINITIONS

3.1. Chain-of-Custody - a log for check-in/check-out of evidence items.

3.2. Failure - as used in this procedure means any failure of pipe, weld, fusion, or component of a Company pipeline facility such as, but not limited to, material failures and/or construction defects, that causes the pipeline facility to become nonfunctional. Failures subject to investigation include those involving:

3.2.1. Unintentional release of gas (loss of pressure containment)

3.2.2. Pipeline component malfunction – does not necessarily require release of gas, but could result in inadequate control of gas pressure or flow.

3.2.3. Pipe damage – serious corrosion, cracking, deformation, mechanical damage or other impairment of the pipe (does not necessarily require unintentional release of gas, but represents a serious hazard requiring immediate response.)

3.2.4. Evidence of ineffective threat mitigation – indications are apparent that existing procedures are not effective in mitigating a serious threat to pipeline integrity (even if none of the three modes of failure described above have occurred).

3.3. Local Investigation Team - a team of employees organized or assigned at the local level by a Region Manager to investigate accidents and/or failures which do not meet the criteria as defined in paragraph 3.4 or which are not investigated by the Pipeline Accident Investigation Team. This team may be required to assist the Pipeline Accident Investigation Team when the situation merits.

3.4. Pipeline accident or incident / event - an occurrence reportable under requirements defined in 49 CFR Part 191 which meets either of the following:

3.4.1. An event that involves a release of gas from a pipeline and

a. A death, or personal injury necessitating in-patient hospitalization; or

b. Estimated property damage, including cost of gas lost, of the company or others, or both of $50,000 or more.

3.4.2. An event that is significant, in the judgment of the Company, even though it did not meet the criteria listed in paragraph 3.4.1.

NOTE:	*In the event that the cause of the accident/failure is readily apparent (e.g. vehicular damage to a facility) and there is no obvious reason or advantage to mobilizing the formal Pipeline Accident Investigation Team, a local investigation team may perform the investigation of a DOT-reportable incident with the concurrence of management.*

3.5. Pipeline Accident Investigation Team - a team of employees organized under the direction of Company management to analyze major pipeline accidents and failures primarily as defined in paragraph 3.4.

3.6. Root Cause Analysis – Methodology applied to determine the primary cause (root cause) of a failure. Involves consideration of cause-and-effect relationships, and may be supported by one or more analytical tools (e.g. Fishbone diagramming.) Typically, root cause analysis involves consideration of four-steps:

3.6.1. Identification and documentation of a failure.

3.6.2. Analysis and identification of root (primary) causes of failure.

3.6.3. Identification of possible corrective actions, where applicable.

3.6.4. Integration of findings / corrective actions into existing operational or design programs, where applicable.

3.7. Specimen - as used in this procedure means steel or plastic pipe segments, associated components, other facilities affected by the failure, or environmental soil and water samples taken from the area under investigation. This term may also be used to label items or materials not defined that will be used as evidence.

3.8. Team Chairman - an individual from the Pipeline Accident Investigation Team designated by Company management to lead activities of the team, including oversight of accuracy and thoroughness of the work.

4. SAFETY

4.1. Appropriate personal protective equipment should be worn when the presence of personnel is required at a field investigation site (refer to Standard Practice 8-10-00).

4.2. On-site investigation will not proceed until such time that the accident situation has been controlled and there are no imminent hazards.

4.3. Ensure preventative measures are taken to avoid exposure to hazardous atmospheres.

5. PERSONNEL QUALIFICATIONS

5.1. Personnel responsible for pipeline accident and failure investigation will be familiar with the procedures outlined herein.

5.2. These procedures are applicable to investigation of failures and accidents at pipeline facilities, but they are not intended as operational or maintenance procedures. They are restricted to defining the administrative procedures (e.g. observation, etc.) for an investigation. Administrative personnel involved with on-scene implementation of these procedures shall not engage in "hands on" removal or modification of failed facilities (e.g. physical cut-out, removal, modification) at in-service pipeline facilities.

5.3. Utilize qualified operational personnel, as needed, for removal, modification, or replacement of pipeline-related facilities.

5.4. Incident investigations shall consider whether human error caused, or contributed, to the incident. Where applicable, investigations shall examine relevant training and qualification programs, and shall specifically consider if previous unidentified Abnormal Operating Conditions were encountered as part of the incident. Any needed training or re-qualification program improvements shall be coordinated with the Operations Training Department (refer to written Company DOT Operator Qualification Plan).

6. INVESTIGATION RESPONSIBILITIES

6.1. Investigation of pipeline accidents and failures will begin as soon as possible after the emergency.

NOTE: *In the event that an accident/failure does not meet the requirements as outlined in paragraph 3.4, the investigation will be conducted at the local level.*

6.2. Major pipeline accidents and failures, as discussed in paragraph 3.4, will be investigated by the Pipeline Accident Investigation Team, if it is likely that the additional analysis could provide data useful in minimizing the possibility of recurrence.

6.2.1. The Pipeline Accident Investigation Team will consist of representatives of appropriate areas appointed by company management.

6.3. Other types of failures will be handled at the local level under the general direction of the Region Manager and coordinated with appropriate personnel to minimize the possibility of any recurrence.

6.3.1. Local management will be responsible for the following:

a. Ensure notification of construction defect or material failure is obtained from appropriate personnel that have knowledge of such failures.

b. Ensure failure specimens are collected (as required).

c. Ensure appropriate personnel are knowledgeable of proper investigation procedures, and that investigation is initiated in a timely fashion to prevent loss of evidence.

d. Ensure photographs are taken of the scene as needed. Note the location on a diagram of the failure scene where pictures were taken (refer to paragraph 12).

e. Ensure that gas samples are collected and/or odorant level is verified, as applicable.

f. Coordinate failure information with Supervisor, Operations Training and Supervisor, System Integrity or other personnel who will assist in the failure analysis.

g. Report summary findings of failure investigation, including probable root-cause of failure, to Pipeline Compliance for inclusion in DOT Central File.

NOTE:	*Failure information for transmission facilities is also maintained within a centralized database maintained by the Integrity Management department. Results of root-cause failure investigations involving transmission facilities shall also be reported to the Integrity Management department for inclusion in the centralized database.*

h. Provide any appropriate or necessary recommendations on prevention of recurrence. Such recommendations should address the identified root-cause of failure, and may involve:

i Technical deficiencies or limitations in existing procedures, material specifications, or design criteria.

ii Organizational factors that contributed to the failure.

iii Opportunities to avoid or mitigate future similar failures.

i. Identify any Operator Qualification related issues including needed re-qualifications (refer to written Company DOT Operator Qualification Plan).

6.3.2. Where specified, the local investigation team will work at the direction of an attorney assigned by the Legal Department under Attorney-Client Privilege.

7. PIPELINE ACCIDENT INVESTIGATION TEAM MOBILIZATION

7.1. The team chairman will be advised of a pipeline accident meeting the criteria in paragraph 3.4 at the earliest available opportunity. Another team member will be notified and designated as acting team chair, if team chair is not available.

NOTE:	*Notification of team chairman will be made by the DOT on-call representative after a determination has been made that the event is (or may be) reportable under 49 CFR Part 191 requirements. In the event the team chairman is not available, DOT on-call representative will consult with management on designation of an acting team chair.*

7.2. The team chairman will:

7.2.1. Consult with appropriate management and legal personnel.

7.2.2. Mobilize accident investigation team to conduct an investigation if it is likely that additional analysis could provide data useful in minimizing the possibility of recurrence.

7.2.3. Utilize on-call lists and/or listings of emergency personnel to mobilize any additional personnel to assist with on-site investigation.

NOTE:	*An incident investigation kit has been prepared for the convenience of the Pipeline Accident Investigation Team. The kit is secured in the 1078 building and contains various items that may be useful during an on-site failure investigation.*

7.2.4. Ensure that gas samples are collected and/or odorant level is verified, as applicable.

7.2.5. Coordinate on-site investigation in a timely fashion to prevent loss of evidence.

7.2.6. Coordinate with officials from investigating agencies, as needed.

7.2.7. Verify that any post-accident drug or alcohol testing of employees required by Company procedures and/or federal regulations have been initiated.

7.2.8. Make arrangements for any supplemental resources that may be appropriate for the investigation.

8. LOCAL INVESTIGATION TEAM RESPONSE

NOTE:	*In the event that an accident/failure does not meet the requirements as outlined in paragraph 3.4, the investigation will be conducted at the local level, led by a local investigation team acting under the general direction of the Region Manager. Depending on circumstances, the team and investigation may be formal or informal in nature. The scope of a local investigation shall be appropriate for the specific circumstance involved.*

8.1. Ensure affected supervision, Legal and Supervisor, Operations Training (QGC) or Region Operations Manager (QPC) are notified of the failure. Refer to written Company DOT Operator Qualification Plan concerning any OQ related issues.

8.2. Ensure affected supervision and/or appropriate personnel knowledgeable in failure response, evaluation and correction are dispatched to affected facility.

8.3. Ensure Emergency Plan procedures relating to obtaining and reporting emergency information are followed. This will ensure that appropriate notification procedures are followed if a failure is determined to be an incident as defined in paragraph 3.4.

8.4. Conduct the investigation using elements of this procedure that are appropriate under the circumstances involved.

9. FORMAL INVESTIGATION PROCEDURES

9.1. Refer to attached Pipeline Accident Investigation Checklist, shown in Figure 1, to assist with the conduct and documentation of a thorough investigation of the accident.

9.2. Conduct investigation and address all pertinent items on the checklist under the direction of the team chairman or designated on-site coordinator.

9.3. Consider the selection of samples or specimens of the failed facility or equipment for laboratory examination, where appropriate.

9.4. Any news media communication will be conducted pursuant to Emergency Plan procedures.

9.5. Personnel responsible for investigation will perform the following:

9.5.1. Coordinate with company emergency response personnel to verify that the accident situation has been controlled and there are no imminent hazards.

9.5.2. Record events that occur, equipment used, and personnel, customers, or witnesses that visit the site.

9.5.3. Determine probable sequence of events prior to failure, including pertinent operational and maintenance activities.

9.5.4. Interview witnesses (when appropriate) following procedures outlined in paragraph 11.

9.5.5. Certify documents that will be used for evidence as an original or original copy as outlined in paragraph 13.

9.5.6. Take sufficient photographs or video of the failed facility, materials, construction defects and/or surrounding area to support specimens/evidence collected as outlined in paragraph 12.

9.5.7. Follow specimen collection procedures outlined in paragraph 10 when specimens will be required in the investigation.

9.5.8. Secure and maintain specimens/evidence acquired in the investigation in a locked room at appropriate Company office when such specimens will be required for evidence. Send all other distribution system specimens to the Supervisor, Operations Training, (QGC), for analysis.

9.5.9. Complete the appropriate leak repair form when failure involves leakage of natural gas.

9.5.10. If applicable, complete plastic pipe/fitting form as shown in Figure 2 and include lot number if available. Send completed form to the Supervisor, Operations Training, (QGC), who will retain on file for a 3 year period.

10. FORMAL SPECIMEN COLLECTION AND ANALYSIS

10.1. When failure data/specimen collection and analysis involves federally reportable incidents, do not remove such specimens until Company Legal/Insurance personnel and the appropriate jurisdictional agencies have been notified and permission has been received.

10.2. Establish chain-of-custody documentation for specimens. Record persons handling the specimen from time originally taken to final disposition.

10.3. Ensure specimens, when determined necessary, are collected as follows:

CAUTION: *Precautions will be taken when collecting or handling physical evidence to preserve its integrity (e.g. avoid heat effects that may affect metallurgical specimens, preserve important evidence on pipe surface or tear surface fracture face, etc.).*

10.3.1. Take natural gas samples to determine odorization level, if appropriate, in the immediate area or at the failure site as soon as possible after the failure area has been made safe.

10.3.2. Ensure precautions are taken when selecting and collecting specimens of pipeline/components, to minimize change to the granular or molecular structure of the pipeline/components in the areas of investigatory interest. Where possible, use methods of cutting the pipe that avoid heat, such as using pipe cutters or other approved tools. If heat is used to cut the pipe, such as with acetylene on steel pipe, ensure the cut is made far enough away from the failure to avoid damaging critical areas of the specimen.

10.3.3. Avoid damage to the pipe specimen when it is moved by using tools, slings and equipment for removal that will not damage the specimen, coating, or any remaining pipeline/facility.

10.3.4. Take samples of environmental soil and water if corrosion is involved as specified in paragraph 10.4. Consider sampling internal pipeline constituents as needed.

10.3.5. Care should be taken not to destroy evidence associated with the specimen, particularly when removing and preparing for transport. Clean specimen of dirt or other matter only to the extent necessary to allow packaging/transport. Observe handling for any indications of evidence (e.g. hydrocarbon odors in soil) that may be relevant.

10.3.6. Ensure the specimen is properly padded, packaged and secured to protect the specimen surfaces while lifting the specimen from installed area to vehicle or vehicle to storage or when shipping.

10.3.7. Properly identify the specimen as to type of material, coating, install date, method of installation, and installation personnel training and qualifications.

10.4. Ensure environmental soil or water samples are collected as follows when required:

10.4.1. Take environmental soil or water samples from the location nearest the failure site.

10.4.2. Package samples in suitable, labeled containers that will protect them from damage through transportation and storage.

10.5. Complete Figure 2 for plastic pipe and/or Figure 3 for steel pipe and analyze specimen as follows:

10.5.1. Determine pipe/fitting lot number, whenever possible (plastic pipe).

10.5.2. Check plastic pipe for possible damage from squeeze off.

10.5.3. Check fusions on plastic pipe for improper appearance, technique or damage.

10.5.4. Check pipe/fitting/wrap specimens for evidence of rock impingement.

10.5.5. Check steel specimens for corrosion damage.

10.5.6. Consider checking the PH of soil or water samples if steel specimen failure was caused by corrosion to determine soil or water contribution to the corrosion.

11. INTERVIEWING WITNESSES IN FORMAL INVESTIGATIONS

11.1. Coordinate formal witness interviews with the Legal Department. Whenever possible, have the witness record his/her statement in his/her own handwriting.

11.2. Obtain the witness's signature on the statement, if possible, along with date, time and place.

11.3. Ensure statement covers relative information and where possible has an introduction, body covering all the areas pertinent to the investigation, and a conclusion. Include a place for all parties to sign, along with date, time and place.

12. TAKING EFFECTIVE PHOTOGRAPHS OR VIDEOS

12.1. Take photos or videos of the overall area including the points of failure/damage.

12.2. Take close-up photos or videos of failed or damaged facilities for clarity.

12.3. Record information about each photo that indicates the photographer, how far away the photo was taken from the subject, the lens used, shutter speed (when applicable). If relative size is important, consider including a common article such as a ruler that helps convey a proper sense of scale.

12.4. Make entries to the chain-of-custody log that includes the processing establishment. Retain the processing envelope, negatives, and receipts for payment as part of the chain-of-custody.

12.5. Retain original video using an appropriate chain-of-custody log.

13. CERTIFYING DOCUMENTS

13.1. Whenever possible, use original document as evidence.

13.2. When a copy of an original is to be used as evidence, certify the copy with a declaration similar to the following example:

EXAMPLE:	**I, ________________________________(investigator), certify that I have compared this copy with the original document and that it is a true copy of the original which is in custody of:__________________________ (secure storage custodian) Located at:________________________________**

14. FORMAL INVESTIGATION FINDINGS

14.1. Review the emergency response either as part of the investigation or as a separate review activity. Include in a report to management any recommendations regarding improvements to emergency response practices or procedures.

14.2. The team chairman will respond through the President and CEO to any inquiries about the accident made by the National Transportation Safety Board, U.S. Department of Transportation, or other jurisdictional agencies.

14.3. Determine the probable sequence of events prior to failure. Identify the probable root cause of failure such as overpressure, third party damage, material defect, construction defect, mechanical or corrosion.

14.4. Report the findings of the investigation to the President and CEO, including recommendations to prevent a recurrence of the failure, along with any recommendations for improving procedures, practices or Operator Qualification Program, if appropriate.

14.5. An evaluation of personnel involved in an incident will be conducted if there is reason to believe that an employee's performance of a covered task contributed to an incident. An evaluation shall also be conducted if there is reason to believe that an individual is no longer qualified to perform a covered task (refer to Company DOT Operator Qualification Program Section IV, paragraph D.).

14.6. Coordinate submittal of any DOT incident reports (refer to Company Emergency Plan). The DOT incident report may serve, where appropriate, as the final report for the incident investigation.

15. FORMAL INVESTIGATION FOLLOW-UP

The team will be responsible for any follow-up or additional investigation requested by the President and CEO or team chairman.

PIPELINE ACCIDENT INVESTIGATION CHECK LIST

PART A - EVENT DATA

1. NAME / LOCATION OF INCIDENT: ______________________________
2. NAME / TITLE OF PRINCIPAL INVESTIGATOR: ______________________________
3. EVENT DATE: ______________TIME OF FAILURE: ______________ TIME DETECTED: ______________
4. REPORTED TO:

   OPS: YES______ NO ______ DATE & TIME: ______________________________
   (NATIONAL RESPONSE CENTER)

   STATE PIPELINE SAFETY OFFICE: YES______ NO ______ DATE & TIME: ______________________________

   REPORTED BY: ______________________________ TITLE: ______________________________
5. GENERAL DESCRIPTION OF EVENT: ______________________________
6. WHERE ACCIDENT OCCURRED: ______________________________
7. WHEN ACCIDENT OCCURRED (DESCRIBE TIME LINE): ______________________________
8. APPARENT ROOT CAUSE: ______________________________
9. EXPLOSION: YES______ NO______ REMARKS: ______________________________
10. FIRE: YES______ NO______ REMARKS: ______________________________
11. ORIGIN OF IGNITION: ______________________________
12. INJURY/HOSPITALIZATION/DEATH: YES______ NO______DETAILS:(Name, Age, Cause).
13. TRANSMISSION ____ DISTRIBUTION ____ SERVICE ____ NUMBER OF CUSTOMERS OUT: ______________
14. NATURE / DURATION OF OUTAGE: ______________________________

Figure 1

15. REMARKS ON SERVICE RESTORATION: ______________________________
16. DAMAGE TO SYSTEM AND OTHER PROPERTIES: ______________________________
17. ESTIMATED SYSTEM REPAIR COST: ______________________________

18. NAME/ADDRESS/PHONE OF AFFECTED PROPERTY OWNERS: ______________________

19. DESCRIPTION OF BUILDINGS / PROPERTIES INVOLVED: ______________________

20. TYPE AND AMOUNT OF DAMAGE TO BUILDING OR OTHER PROPERTY: ______________________

21. ESTIMATED COST OF TOTAL PROPERTY DAMAGE, INCLUDING COST OF LOST GAS, DAMAGE TO COMPANY FACILITIES AND OTHERS:

PART B – RESPONSE

22. TIME ORDER (NOTIFICATION) RECEIVED: ______________________

23. TIME ORDER DISPATCHED: ______________________

Figure 1 (Continued)

24. NAME OF EMPLOYEES DISPATCHED AND TIME OF THEIR ARRIVAL: ______________________

25. TIME NATURAL GAS WAS CUT OFF AND METHOD USED TO DO SO: ______________________

26. NAME OF OFFICIALS IN CHARGE OF FIRE / POLICE DEPARTMENT, AND OTHER CHIEF EMERGENCY RESPONDERS ON-SCENE:

PART C – FACILITY DATA

27. DESCRIBE GAS FACILITIES INVOLVED: ______________________

28. LINE SIZE: ______________________ OPERATING PRESSURE: ______________________

29. MAOP: ______________________ MATERIAL DESCRIPTION: ______________________

29. MAPS / DRAWINGS (Attach copies): YES _______ NO _______

30. NAME / TITLE OF PRIMARY OPERATING CONTACT AT COMPANY FOR FACILITIES INVOLVED: ______________

____

PART D – INVESTIGATION

31. HAS THE COMPANY PIPELINE ACCIDENT INVESTIGATION TEAM BEEN MOBILIZED?

    YES _______ NO _______

32. HAS THE AREA AROUND THE PIPELINE ACCIDENT SCENE BEEN SECURED TO PREVENT ANY TAMPERING WITH ITEMS ASSOCIATED WITH THE ACCIDENT SUCH AS EQUIPMENT, MACHINERY, DEBRIS FROM ACCIDENT, RELATED EQUIPMENT FACILITIES, AND VEHICLES?

    YES _______ NO _______

Figure 1 (Continued)

33. PRIOR TO INITIATING ON-SITE INVESTIGATION, HAS COORDINATION WITH COMPANY EMERGENCY RESPONSE PERSONNEL TAKEN PLACE TO VERIFY THAT SITUATION HAS BEEN CONTROLLED AND THERE ARE NO IMMINENT HAZARDS?

    YES _______ NO _______

34. HAS A LOG BEEN INITIATED TO RECORD EVENTS THAT OCCUR DURING THE INVESTIGATION, EQUIPMENT USED, AND PERSONNEL, CUSTOMERS, OR WITNESSES THAT VISIT THE SITE? (Attach copy)

    YES _______ NO _______

    (Identify names / titles of investigators present for public safety agencies.)

35. WAS POST-ACCIDENT DRUG AND ALCOHOL TESTING CONDUCTED AS REQUIRED BY DOT REGULATIONS?

    YES _______ NO _______ REMARKS: ____

    ____

36. HAS THE FOLLOWING DATA BEEN COLLECTED ABOUT THE PIPELINE/FACILITY, IF WARRANTED:

    a. TYPE OF FACILITY _______
    b. GRADE, SIZE AND WALL THICKNESS OF THE PIPE _______
    c. YEAR OF INSTALLATION/INSTALLED BY _______
    d. COVER / BACKFILL CONDITIONS _______
    e. MANUFACTURER OF PIPE, VALVES, REGULATORS, RELIEF VALVES, ETC. _______
    f. APPLICABLE CODES AT TIME OF PIPELINE/FACILITY INSTALLATION _______
    g. WELDING / FUSING PROCEDURES USED _______
    h. MAINTENANCE / LEAK HISTORY OF THE PIPELINE/FACILITY _______
    i. MAOP OF THE PIPELINE FACILITY / OVERPRESSURE PROTECTION _______
    j. CONSTRUCTION / TEST RECORDS OF PIPELINE / FACILITY _______
    k. CATHODIC PROTECTION, IF ANY _______
    l. ODORIZATION OF GAS _______
    m. RECORDS OF ANY MODIFICATIONS TO THE PIPELINE / FACILITY _______
    n. GAS QUALITY / GAS QUALITY ISSUES, IF ANY _______
    o. WRITTEN OPERATING PROCEDURES, IF ANY _______
    p. MAPS / DRAWINGS _______

    COLLECT COPIES OF ORDERS, ROUTE SHEETS, ETC., RELATING TO INCIDENT THAT QUESTAR MIGHT BE CALLED ON TO PRODUCE AT A LATER DATE (Certify all copies held for evidence).

37. WERE FACTS (PROBABLE SEQUENCE OF EVENTS) DETERMINED LEADING UP TO THE ACCIDENT, SUCH AS:

    a. THE MANNER IN WHICH THE PIPELINE FACILITY WAS OPERATED _______
    b. ACTIONS FOLLOWED BY COMPANY PERSONNEL. _______
    c. ACTIONS FOLLOWED BY NON-COMPANY PERSONNEL _______

Figure 1 (Continued)

    d. ACTIONS/ACTIVITIES ON THE PART OF COMPANY OR NON-COMPANY PERSONNEL _______

(INCLUDING PERTINENT OPERATION & MAINTENANCE ACTIVITIES)

e. OPERATION OF PIPELINE / SAFETY EQUIPMENT ________

f. ANY SIGNIFICANT FACTOR NOT RELATED TO PIPELINE OPERATIONS ________
(ACT OF GOD, GEOLOGIC FORCES, WEATHER, ETC.)

g. RECORDS / INFORMATION RELATING TO ADDRESS / LOCATION PRIOR TO ACCIDENT ________

h. RECENT LOCATE REQUESTS / CONSTRUCTION ACTIVITIES ________
(Attach applicable records to this form).

38. ARE ALL ITEMS PERTINENT TO THE ACCIDENT THAT MAY BE USED AS EVIDENCE TAGGED, LABELED AND RETAINED FOR SAFE KEEPING? (Contact Legal, Insurance, Jurisdictional Agencies prior to removing.)

YES ________ NO _______

REMARKS:
____

39. HAS A LIST BEEN PREPARED OF ITEMS TAGGED OR LABELED AND IN WHOSE POSSESSION IS SAID EVIDENCE?

YES ________ NO _______

REMARKS: ____

40. PRESSURE TESTED, OR BAR TESTED, SERVICE LINE (Attach Details): YES_____ NO_____ N/A_____.

41. BAR TESTED MAIN IN FRONT AND ADJACENT TO LOCATION (Attach Details): YES_____ NO_____ N/A____.

42. BAR TESTED AREA AROUND BUILDING: YES______ NO____ (Attach Details) N/A____.

43. SAMPLE OF GAS FROM BAR HOLE AND PIPELINE IF REQUIRED: YES______ NO _______ (Attach Details).

44. METER NUMBERS AND INDEX READINGS AT TIME OF ACCIDENT (IF APPLICABLE): ______________________
____

45. METER HISTORY - DATE OF TURN ON, LAST METER READING AND INDEX READING AT THAT TIME (IF APPLICABLE) ____

46. PHOTOGRAPHS OF BUILDINGS AND CONTENTS: YES ____ NO ____ N/A _____

(Note on diagram where pictures were taken. Ensure picture taking is witnessed).

47. FAILED FACILITY VISUALLY EXAMINED FOR EVIDENCE OF CORROSION, EXTERNAL DAMAGE, ETC.:

YES ________ NO _______

REMARKS: ____

(Attach details, if any. Note type of damage – e.g. cracking, wall loss, mechanical damage, etc. Note position and size of damage – e.g. o'clock orientation, depth, length, circumferential extent, etc.)

48. PHOTOGRAPHS OF FAILED FACILITY AND SURROUNDING AREA: YES _____ NO _____ N/A ______

(Note on diagram where pictures were taken. Ensure picture taking is witnessed).

49. DIAGRAM OF ACCIDENT SCENE: YES _____ NO _____ (Attach diagram to this form).

Figure 1 (Continued)

50. METALLURGICAL ANALYSIS REQUIRED? YES ____ NO ____ (Attach Details).

51. SOIL TEST ANALYSIS REQUIRED? YES _____ NO ______ (Attach Details).

52. COMPLETE WEATHER REPORT REQUIRED? YES ____ NO ____ (Attach Details).

53. ODORANT REPORT COMPLETED? YES _____ NO ____(Attach Details) N/A____.

54. WAS INFORMATION OBTAINED ON RESPONSE OF COMPANY PERSONNEL TO THE EMERGENCY?

YES _______ NO ________

REMARKS: ____
____
____
____

55. STATEMENTS FROM EMPLOYEES WHO WERE AT THIS ADDRESS PRIOR TO ACCIDENT OR AT TIME OF ACCIDENT, IF APPLICABLE? (When and what were their actions? Attach Details).

YES ________ NO _______

56. STATEMENT FROM WITNESS OR A BRIEF DESCRIPTION OF WHAT WAS SAID (Attach statements to this form).

    YES ________ NO _______

57. REMARKS ON SOURCE OF ANY CONTRIBUTING FACTORS FROM OTHER FACILITIES OR LOCATIONS: ________

PART E – FOLLOW-UP EVALUATION

58. D.O.T. 30-DAY INCIDENT REPORT REQUIRED?

59. YES____ NO____ (Attach copy).

60. HAS AN EVALUATION BEEN MADE OF THE PIPELINE/FACILITIES OPERATING PROCEDURES FOR COMPLIANCE WITH FEDERAL AND INDUSTRY CODES?

    YES _______ NO _______

    REMARKS: ________

61. HAS A REVIEW BEEN MADE TO DETERMINE WHETHER ESTABLISHED COMPANY PROCEDURES WERE FOLLOWED AT THE TIME OF THE ACCIDENT?

    YES _______ NO _______

    IF DEVIATIONS WERE MADE FROM ESTABLISHED PROCEDURES, WAS THERE A REASON FOR DEVIATION?

    REMARKS: ________

Figure 1 (Continued)

62. IF LOCAL POLICE / FIRE DEPARTMENT PERSONNEL RESPONDED TO THE ACCIDENT SCENE, WAS A REVIEW CONDUCTED OF THE INTERACTION BETWEEN COMPANY AND EMERGENCY RESPONSE PERSONNEL? ALSO, WERE POLICE / FIRE DEPARTMENT PERSONNEL ACQUAINTED WITH PROCEDURES TO FOLLOW DURING A PIPELINE EMERGENCY?

    YES _______ NO _______ YES _______ NO _______

    REMARKS: ________

63. HAS PROBABLE CAUSE (ROOT CAUSE) BEEN DETERMINED?

    YES _______ NO _______

64. INVESTIGATION REPORT COMPLETED? YES_____ NO ______

65. RECOMMENDATIONS: ________

    OTHER REMARKS: ________

Figure 1 (continued)

PLASTIC PIPE/FITTING FAILURE
D.O.T. REQUIRED REPORT

LOCATION:		DATE:	
FOREMAN:		DIVISION:	
PLEASE ATTACH COPY OF L.R.O.			
FILL IN BLANKS AND CHECK APPRPRIATE BOXES			
SIZE MAIN:		SERVICE:	
OPERATING PRESSURE:		DIRECT BURY _____	PLOW ____ INSERT _____
TYPES OF MATERIALS:	ALDYL A ______	TR-418 ______	
FAILURE IN:	PIPE ______	FITTING _______	FUSION ______
FITTING TYPE:		FITTING SIZE:	
TYPE OF FUSION:	BUTT ______	SOCKET ______	SADDLE ______
PIPE LOT #		DATE INSTALLED:	
FAILURE ON:	TOP ______	SIDE ______	BOTTOM ______
PROTECTIVE SLEEVE IN PLACE:	YES ______	NO ______	
ALIGNMENT OF FITTING:	CENTERED ______	OFFSET _______	
CAUSE OF FAILURE		INCORRECT FUSION ______	
		INCORRECT INSTALLATION ______	
		INADEQUATE COMPACTION ______	
		EXTERNAL FORCE ______	
		3RD PARTY ______	
		OTHER ______	
SOIL TYPE:	CLAY ______	LOAM ______	SANDY ______

REMARKS (sketch on back) ____________________
____
____
____
RETURN TO: OPERATIONS TRAINING DNR530

Figure 2

QUESTAR GAS LABORATORY ANALYSIS	
Manufacturer:	Date Received:
Type of Sample:	Size of Sample:
COMPLAINTS Remarks: ______________________________	
VISUAL INSPECTION Remarks: ______________________________ Inspected By: ____________ Employee Number: ____________ Date: ________	
LAB TEST Remarks: ______________________________ Inspected By: ____________ Employee Number: ____________ Date: ________	
RETURN TO: Operations Training DNR530	

Figure 3