A

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 16, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5005M

Dear Mr. Tutcher:

On May 7-12, 2001, a representative of the Central Region, Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your manuals at Duluth, MN in conjunction with a system type inspection of Lakehead facilities.

As a result of a review of your operating and maintenance manual, the requirements for which are set forth in Section 195.402(c), specifically under 195.402(c)(3)and 195.402(c)(13),the following inadequate procedures were noted:

§ 195.402 Procedural Manual for Operations, Maintenance and Emergencies.

§ 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

1. **§ 195.402(c)(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart.**

A. **§ 195.401 General requirements.**

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

1. Lakehead procedures need revision to include verbiage about including first discovery reports from all sources such as the public, employees, contractors, etc. and not just reports made to Lakehead Pipeline's Control Center.

2. Lakehead has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of Lakehead's pipeline systems, especially with regard to internal corrosion control procedures and remedial actions taken. However, Lakehead has not formalized the process by inclusion of specific verbiage in Lakehead's O & M manual.

B. **§ 195.420 Valve maintenance.**

§ 195.420(b) Each operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

Lakehead's procedures for valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, Lakehead inspects valves twice per calendar year, per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. Lakehead did have one valve inspection interval that was exceeded due to flooding, and it was suggested to Lakehead Pipeline personnel that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

C. § 195.432 Breakout tanks.

§ 195.432(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).

Lakehead's procedures need specific verbiage on what items to look for during tank inspections as found in Section 4 of API 653.

D. **§ 195.432(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.**

Lakehead's procedures need revision to include verbiage on what the corrective action process is if problems are found during any breakout tank inspection. Lakehead should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions. Lakehead's procedures also need specific references to industry standards API 2003 and API 2510.

2. **§ 195.402(c)(13) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.**

Lakehead procedures need revision to include verbiage about what Lakehead does for analysis and investigation of abnormal operating events to prevent recurrences of the events.

As provided in 49 C.F.R. §190.237, this Notice of Amendment serves as your notification that this office considers your procedures inadequate. Under 49 C.F.R. § 190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or a request for a hearing within 30 days after receipt of this Notice. After reviewing the record, the Associate Administrator for Pipeline

Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 C.F.R. § 190.237. If you do not wish to contest this Notice of Amendment, please provide your revised procedures within 30 days of receipt of this notice.

If you have any questions in regard to this matter, please contact me at (816) 329-3800.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
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ENBRIDGE™

Certified Mail

May 16, 2002

Mr. Ivan Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locus Street, Room 462
Kansas City, MO 64106

Dear Mr. Huntoon:

CPF No. 3-2002-5005M

This is in response to your "Notice of Amendment" letter addressed to Mr. Dan C. Tutcher, dated April 16, 2002. Your letter identified several issues resulting from a review of our operating and maintenance manuals during an on site safety audit in Duluth, Minnesota in May of 2001. Enbridge is a responsible operator, and we value the opportunity to address these items. We also appreciate the working relationship demonstrated by this approach. Following are the specific items you identified, and our response to each item, respectively:

1. **A. Section 195.401 General requirements.**

   1. A survey of our field locations identified an existing form that's utilized to document "first discovery" information. This form will be updated with current Enbridge terminology and referenced in our O & MP Manuals. A copy of the existing form is attached.

   2. Copied below is an excerpt from the corrosion control section of our O & MP Manual, Book 3 08-02-01 revised based on recommendations from the May audit.

      Monitoring
      Take manual hydrogen foil readings at least 10 times per year with intervals not exceeding six weeks; however, make every effort to take readings once per month.

      Note: During cleaning and/or inhibitor injections, Pipeline Integrity may increase the frequency of hydrogen foil readings.

      Note: Remote hydrogen foil readings are directly reported to online communications systems. Pipeline Integrity regularly monitors remote readings and takes corrective action as required (e.g., manual readings may be required at remote locations as directed by Pipeline Integrity).

      Pipeline Integrity reviews hydrogen foil activity annually to assess overall internal corrosion mitigation, and initiates remedial action based on conclusions

      Note: For more information on the company's internal corrosion monitoring and corrosion inhibitor program, contact Pipeline Integrity.

B. Section 195.420 Valve maintenance.

The confusion noted in the valve inspection criteria was the need to witness the remote operation twice a year. The existing wording in our O & MP Manual Book 3; 03-02-01 page 5 of 6 reads, "Mainline valves must be inspected at least twice each calendar year at intervals not to exceed 7 ½ months." Copies of the exact wording and Maximo work plans are attached. An e-mail from David Barrett on 2-22-02 confirmed that we aren't required to witness the remote operation twice a year, but have procedures in place to verify the integrity of the remote capabilities for emergency response isolation.

C. Section 195.432 Breakout tanks.

Section 195.4342(b)
A section of our O & MP Manual, Book 3, 09-02-02 is attached which was modified to outline what items we inspect on routine and annual inspections based on recommendations from the May audit.

D. Section 195.432 Breakout tanks.

Section 195.432(c)
A section of our O & MP Manual, Book 3 09-02-02 is attached which was modified to address the need to complete follow up to all tank inspections based on recommendations from the May audit.

We question the need to reference API 2510 in our O & MPs. That is the construction standard for pressure vessels and doesn't appear to be pertinent to operating. We reference API 510 (Inspection and Maintenance) and API 2026 (Safe Entry on Roofs) as required by 195.405.

2. Section 195.402(c)(13)

We have a question on what portion of Part 195 you are referring to. 195.402(c) covers "Normal Operating Conditions" but you refer to "Abnormal Operating Conditions" in your letter, which are 195.402(d). We have reviewed our current operating manuals and procedures and believe that we are in compliance with the requirements outlined in 195.402 (d) that requires us to periodically review the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

Specifically, **Book 7: Emergency Response Section 02-02-01, Notification,** documents the following requirements:

"Any reported or observed emergency or possible emergency situation must be given an emergency status until the report is confirmed or negated. Apply the same notification procedures to emergencies involving product released, fires, bomb & security threats, and injuries."

Our procedures clearly document that it is the responsibility of the Control Center to respond to, investigate and correct for the following abnormal operating conditions including:

- unintended value closure or shutdown.
- increase or decrease in pressure or flow rate outside normal operating limits
- loss of communications
- operation of a safety device
- any other malfunction or a component, deviation from normal operations, or employee error that could cause a hazard to persons or property.

The Control Center operating procedures are documented in a lotus notes database and **Section A. Emergency Procedures, 4. Incident Analysis e) Abnormal Operating Conditions** provides direct guidance to control center staff who have the responsibility for abnormal operating conditions. Specifically, **Section G. Administration, 1. Procedure Administration, b) Abnormal Operation Procedure Review** requires the following review of response and evaluation of effectiveness:

"After an initiated response of an Emergency Procedure or abnormal operation occurs:
1. Within 24 hours perform an initial procedure review to determine effectiveness of the procedure.
The initial procedure review shall include the following personnel:
- Control Center Coordinator on-shift during abnormal operation
- Control Center Operator on-shift during abnormal operations
2. If the procedure requires modification, notify Supervisor
3. Supervisor will initiate procedure change
4. Procedure will be modified and personnel shall be informed of change."

I trust that these explanations and proposed action plans have addressed the concerns outlined in your letter. Should you have any further questions or concerns, please feel free to contact me at (218) 725–0505.

Sincerely,

John Sobojinski

John R. Sobojinski

Attachments

RECEIVING EMERGENCY INFORMATION FORM

IPL/LPL

Date and Time of Report: ____________

A. CALLER:

Name of Person Reporting: ____________

Caller's Location: ____________

Caller's Telephone: (Next 2 hrs) ____________ (Home) ____________

Caller's Address: ____________

B. EMERGENCY DESCRIPTION:

Condition Observed: ____________

____

Facility Involved, Location, or Mile Post: ____________

____

Date and Time Incident Observed: ____________

County and Nearest City/Township: ____________

Local Directions to Site: ____________

____

Nearest River, Stream, Lake (Direction & Distance): ____________

____

Other Helpful Information (Weather, Wind, Roads, Public): ____________

Are There Any Injuries?: ____________

GIVE WARNING INFORMATION FOR NGL/CRUDE OIL (FOUND ON REVERSE PAGE)

C. EMERGENCY REPORTING

Did Caller Notify Police? ____________ When? ____________ Police on Site? ____________

Are Other Emergency Response Agencies on Site? ____________

____

INTERNAL REPORTING

District Mgr or On-Call Designate Notified: Time ____________ Name ____________

Emergency Response Agency/Police Notified (See guide on reverse of form)

Time ____________ Name ____________

Other Notifications: Time ____________ Name ____________

Time ____________ Name ____________

Control Center Notified: Time ____________ Name ____________

Line Shutdown Requested? ____________ Line Shutdown Time: ____________

D. OTHER INFORMATION

____

____

____

Name of Employee Receiving Report: ____________

6/89

NGL WARNING INFORMATION

Note: If a "White Vapor Cloud" is sighted, associated with an NGL line, the caller must be warned of the danger. (Use A or B below to give caller instructions.)

A. If the cloud is visible but some distance away the person should:

1) Turn off gas pilot lights.
2) Turn off all electric power — at least unplug refrigerators or freezers.
3) Observe and stay away from the vapor cloud. Do not drive any automotive vehicle toward or into vapor cloud. If necessary to leave home, go to the nearest neighbor. Warn other neighbors by telephone.

B. If the cloud is visible and gas odor is present the person should:

1) Leave the dwelling immediately.
2) Do not start any automotive vehicle. Do not strike matches or cause any open flames.
3) Walk away from the vapor cloud.
4) Keep away from vapor cloud and proceed to nearest neighbor.

C. As soon as these instructions have been relayed, advise the person that we will contact the police and help will be on the way at once.

CRUDE OIL WARNING INFORMATION

All crude oil is flammable and toxic.

Do not approach a crude oil leak.

Stay out of buildings.

Leave the area if the leak is within 800 meters (½ mile) of your property.

Do not return until advised.

USA

Valve Inspection

Mainline valves, including remotely operated valves, must be inspected according to Maximo MP107 and MP256 at least twice during each calendar year at intervals not to exceed 7½ months.

In addition to the above, at least once each year the remote operation (i.e., open and close from control center) of remotely operated mainline valves must be verified according to Maximo MP179.

USA

Overpressure Safety Devices

Devices that limit, regulate and/or control maximum operating pressure must be inspected, tested or calibrated regularly according to Maximo:

- EP244 for pressure relief valves
- EP268 for pressure transmitters
- EP269 for pressure switches
- ET313 for OQT pressure allowable setpoints
- MP251 for pressure relief valves in crude service
- MP255 for pressure relief valves in NGL service
- MP290 for OQT pressure control valve system
- MP251 for OQT relief valve inspection and testing

Engineering, in cooperation with Operations employees, is responsible for determining if any device becomes inadequate in capacity and/or reliability for its intended purpose, and for ensuring the device is upgraded or replaced.

Records

CAN

Aerial Patrol Reports

Patrol pilots must document aerial inspections in the Aerial Patrol Report database. The report summarizes inspection dates and any abnormal conditions observed. Aerial Patrol Reports are permanently retained in the database and may be filed and at the regional office responsible for the area covered in the report.

NOTE: For Enbridge Pipelines (NW) Inc, the Aerial Patrol Report database is in the Lotus Notes NW Forum.

BOOK 3: PIPELINE FACILITIES

ENBRIDGE

Section
STANDARDS

09-02-02
Subject Number

Subject
Tank Inspections

Purpose

Atmospheric crude oil tanks and pressurized tanks are inspected to confirm structural integrity and continued fitness for use.

Requirements

Frequency

Inspect atmospheric tanks on a schedule consistent with API 653, Section 4—Inspection, and for pressurized tanks consistent with API 510, Section 6—Inspection and Testing of Pressure Vessels and Pressure Relief Devices. Table 1 and Table 2 summarize the types and frequencies of tank inspections.

Table 1
Atmospheric Crude Oil Tank Inspections

Inspection	Frequency	Who
Routine In-Service	monthly	local terminal operations employee[1]
Annual In-Service	annually	local terminal operations supervisor, PLM supervisor, or designate
Formal In-Service	5 years[2]	company employee[3] or third party inspector (preferred)[3]
Formal Out-Of-Service	20 years[2,4]	company employee[3] or third party inspector (preferred)[3]

NOTES
1 Knowledgeable in tank farm operations, specifics of the tank and characteristics of the product stored.
2 More frequent inspections may be required due to corrosion growth rates.
3 Certified to API 653, Appendix D.
4 Frequency may be extended if a risk-based inspection (RBI) assessment is done according to API 653.

Table 2
Pressurized Tank Inspections

Inspection	Frequency	Who
Formal In-Service	5 years[1]	company employee[2] or third party inspector (preferred)[2]
Formal Out-Of-Service	10 years[1,3]	company employee[2] or third party inspector (preferred)[2]

NOTES
1 More frequent inspections may be required due to corrosion growth rates.
2 Certified to API 510, Appendix B.
3 Frequency is based on "actual service exposed life."

Routine Inspections

Visually inspect the exterior of each aboveground tank monthly for:

- evidence of leaks (e.g., on shell, flanges, mixers)
- changing conditions (e.g., shell distortions, settlement or heaving, active corrosion)
- condition of the foundation, paint coatings, floating roof, insulation systems and appurtenances

---

NOTE: For more information, see the Routine In-Service Tank Inspection Report in the Tank Management database.

Records

Record monthly inspections on the Routine In-Service Inspection Report and retain as follows:

- original onsite
- copy at the regional office

Annual Inspections

Visually inspect each aboveground tank annually for:

- condition of platforms and ladders
- condition of roof legs, manholes, vents, drains
- leaks in pontoons
- condition of seals
- condition of rescue tank davit

Take seal gap measurements as required.

NOTE: For more information, see the Annual Tank Inspection Report in the Tank Management database.

Records

Record annual inspections on the Annual Tank Inspection Report form and retain as follows:

- original onsite
- copy at the regional office

Regional offices must retain Annual Tank Inspection Reports for 2 years.

Formal Inspections

Complete formal inspections in accordance with the inspection schedule for each tank.

NOTE: Inspection schedules are outlined in the Tank Management database for atmospheric crude oil tanks, or are determined by regional engineers for pressurized tanks.

Regions are responsible for scheduling and preparing tanks for formal inspections.

Records

After completing a formal inspection, the certified API inspector must provide an inspection report that includes:

- completed API Tank In-Service Inspection Checklist or Tank Out-of-Service Checklist if applicable
- inspection summary
- discussion of methodology
- detailed discussion of each component inspected
- engineering calculations
- graphs
- recommendations
- photographs
- drawings

Retain inspection reports as follows:

- original onsite
- copy at the regional office
- copy in Operations Services

NOTE: Operations Services maintains and updates the Tank Management database in Lotus Notes that captures all relative data for atmospheric crude oil storage tanks.

Regional offices must retain inspection reports until the next inspection cycle for atmospheric crude oil tanks, or for the life of the tank for pressurized tanks.

Corrective Action

Routine/Annual Inspections

Review results from routine and annual inspections with the area/terminal supervisor.

Area supervisors are responsible to:

- evaluate the need for repairs
- initiate and monitor repairs
- consult with the regional engineer, certified API inspector and Operations Services for unusual or major repairs
- document the completion of repairs

NOTE: Major repairs include re-leveling a tank, welding within the floor-to-shell critical zone or any work requiring a hydrotest.

Formal Inspections

Upon review of the inspection report from the certified API inspector, the area supervisor and regional engineer are responsible to:

- review the recommendations
- initiate and monitor repairs
- consult with Operations Services for unusual or major repairs
- document the completion of repairs or exceptions to the recommendations

U.S. Department
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Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 27, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5005M

Dear Mr. Tutcher:

As a result of an inspection of your Operation and Maintenance Manual on May 7-12, 2001, by a representative of the Central Region, Office of Pipeline Safety (OPS) at Duluth, MN, a Notice of Amendment was issued on April 16, 2002. This Notice required amendment of certain procedures contained within Enbridge (US)'s Operation and Maintenance Manual. We received correspondence and copies of amended pages of Enbridge (US)'s Operations & Maintenance manual, submitted by Enbridge (US) by letter dated May 16, 2002. The revised procedures have been reviewed and found to be acceptable.

In regard to Item 2 of the original Notice of Amendment letter the regulation reference should have been "§195.402(d)(5)" and not "§195.402(c)(13)", since the issue was regarding "abnormal operations". The Office of Pipeline Safety apologies for any confusion this may have caused Enbridge (US) personnel. Enbridge (US)'s explanation regarding this issue contained in Enbridge (US)'s letter dated May 16, 2002 has been reviewed and is found to be acceptable.

This letter is to inform you that no further action is necessary and that this case is being closed. Thank you for your cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED - RETURN RECEIPT REQUESTED

May 15, 2002

Mr. Daniel C. Thatcher
President
Enbridge (U.S.), Inc.
1100 Louisiana St.
Suite 3300
Houston, TX 77002-5217

CPF No. 3-2002-5008-M

Dear Mr. Thatcher:

On February 26 - 27, 2002, representatives of the Central and Eastern Regions, Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an Integrity Management Segment Identification and Completeness Check of Enbridge Energy's integrity management program in Duluth, Minnesota.

Although the inspection found that Enbridge had identified pipeline segments that could affect a high consequence area (HCA) pursuant to §195.452(b), the process Enbridge used in identifying those segments does not appear adequate. It appears that Enbridge's integrity management procedures for the identification of pipeline segments require amendment as follows:

1. **§195.452 Pipeline integrity management in high consequence areas**

§195.452(b)(2) Identification of all pipeline segments that could affect a high consequence area by December 31, 2001.

§195.452(b)(6)(ii) The operator must demonstrate that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

A.) Enbridge used a release volume of 20,000 barrels as the basis for its determination of pipeline segments which could affect high consequence areas (HCAs). According to Enbridge this represents a spill volume which is larger than 99% of historical leaks that have occurred on the Enbridge system. However, Enbridge indicated that a reportable leak of 40,500 barrels occurred in 1991. Subsequent review of OPS Accident Report data shows that Enbridge also experienced a 31,300 barrel leak in 1989. OPS proposes that your process be modified to provide adequate technical justification for the determination of the spill volume in light of the fact that Enbridge has actually experienced leaks larger than the 20,000 barrel volume used in its analysis. This is necessary to assure that all pipeline segments which could affect HCAs are actually identified in Enbridge's integrity management program.

B.) In the determination of those pipeline segments which could affect a HCA, a strophoid (teardrop) shaped spill pool extending 1,770 feet from the pipeline was used. It was also assumed the spill volume of 20,000 barrels would be uniformly distributed over the teardrop shape at 1 inch thick. This method does not adequately account for overland transport due to the effects of varying terrain, ditches, specific liquid flow characteristics, and other factors which could carry a liquid spill further than 1,770 feet from the pipeline overland. OPS proposes that Enbridge's process be modified to include the effects of overland transport to ensure that all pipeline segments which could affect HCAs are identified.

C.) In the case of pipelines transporting natural gas liquid (NGL), a ½ mile buffer was used to determine those segments which could affect HCAs. The ½ mile buffer was not supported in Enbridge's process by adequate technical justifications. In order to support the determination of an adequate buffer zone for NGL pipelines, OPS proposes that your process be modified to include a technical analysis of the predicted vapor dispersion due to a leak of the NGL's transported in your system.

When it is found that an operator's plans and/or procedures are inadequate the operator, after notice and opportunity for hearing as provided in 49 C.F.R. §190.237, may be required to amend its plans and procedures. This letter serves as your notification of inadequate plans and procedures as well as your response options as prescribed under §190.237. The operator is allowed thirty (30) days after receipt of such notice to submit written comments or request an informal hearing. After considering the material presented, OPS is required to notify the operator of the required amendment or withdraw the notice proposing the amendment. If you do not desire to contest the notice, within thirty(30) days of receipt of this notice you must prepare the revised procedures and provide a copy to:

Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
901 Locust St, Room 462
Kansas City, MO 64106

Also, attached is a description of the response options available to you. Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights. A response which does not contest the allegations in the Notice authorizes the Associate Administrator for Pipeline Safety to find the facts to be as alleged herein and to issue a final order directing amendment.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enclosure

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ENBRIDGE™

June 18, 2002

UPS – NEXT DAY DELIVERY

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2002-5008-M

Dear Mr. Huntoon:

This submittal is in response to the comments detailed in your letter of May 15, 2002 (attached) regarding Enbridge's compliance with HCA pipeline segment identification rules set forth in 49CFR195.452 (from hereon referred to as the "Rule"). As noted in your letter, we have complied with the intent of the Rule. Consistent with the Rule, and stated during our OPS audit last February, a maintenance schedule for our "HCA Pipeline Segment Identification Plan" (Plan) is in effect. Maintenance activities include updating our Plan to reflect engineering evaluations based on new data as they become available. As such, in addition to your amendments reiterated below, we have initiated changes to the Plan to reflect our operational history as relevant to spray zone analysis and the thickness of the overland flow of crude oil.

The following details our response to your comments A) through C):

OPS Comment A):

Enbridge used a release volume of 20,000 barrels as the basis for its determination of pipeline segments which could affect high consequence areas (HCAs). According to Enbridge this represents a spill volume which is larger than 99% of historical leaks that have occurred on the Enbridge system. However, Enbridge indicated that a reportable leak of 40,500 barrels occurred in 1991. Subsequent review of OPS Accident Report data shows that Enbridge also experienced a 31,300-barrel leak in 1989. OPS proposes that your process be modified to provide adequate technical justification for the determination of the spill volume in light of the fact that Enbridge has actually experienced leaks larger than 20,000 barrel volume used in its analysis. This is necessary to assure that all pipeline segments which could affect HCAs are actually identified in Enbridge's integrity management program.

Enbridge Response to Comment A):

As correctly stated during the OPS audit last February, a volume of 20,000 bbls is greater than 95% of the releases experienced by our system. The two releases referred to above are in a higher percentile. A release volume of 20,000 bbls was assumed during the HCA pipeline segment identification process. We feel this was a conservative assumption, and was the best available information at the time.

Also stated during our audit was the fact that we would modify our analysis to reflect location specific potential volume out data as they became available. This still holds true, and we are in the processes of modifying the pipeline segments identified to reflect potential release volumes based upon the profile of the pipelines and location of valves.

OPS Comment B):

In the determination of those pipeline segments which could affect a HCA, a strophoid (teardrop) shaped spill pool extending 1,770 feet from the pipeline was used. It was also assumed the spill volume of 20,000 barrels would be uniformly distributed over the teardrop shape at 1 inch thick. This method does not adequately account for overland transport due to the effects of varying terrain, ditches, specific liquid flow characteristics, and other factors which could carry a liquid spill further than 1,770 feet from the pipeline overland. OPS proposes that Enbridge's process be modified to include the effects of overland transport to ensure that all pipeline segments which could affect HCAs are identified.

Enbridge Response to Comment B):

At the time of the analysis the industry standard was to use a uniform buffer approach. We took the approach one step further by incorporating a shape function to emulate overland flow. In mathematically modeling a physical process, such as overland flow of oil, simplifying assumptions must be made. While the factors mentioned in your response do influence the overland transport (as do scores of others), they would be hard to defend on a system wide basis. In our case, we assumed an oil spill geometry and conditioned the area impacted on the volume out by assuming an average oil thickness and stating that the transport was "detention dominant" – A conservative assumption effectively incorporating viscosity, temperature, and travel time. Calibration (e.g. modeled flow distance –v- flow distance of actual releases) was performed prior to the segment identification process and will be included in future versions of our Plan, as are oil thickness' at actual overland oil releases from our system. At the time of the audit we felt this was as good an estimator as any, and was defensible. Parsimony is a quality all good models have – A more complex model may look impressive, but not be a good predictive model and be very hard to defend (e.g. variable temperature, slope, oil type, roughness coefficients, frozen/unfrozen conditions, travel time...etc over 1,700 miles of our system). As part of our Plan maintenance, new potential volume out data have been made available and will be accounted for in our analysis of overland flow. We have also taken to heart the OPS' comment relating to topographic channeling and have formulated the strophoid geometry to be terrain dependent. Stretching factors to modify plume geometry as a function of the general topographic expression have been developed in a manner consistent with the gradient based approach developed to analyze the potential transport of oil on water.

OPS Comment C):

In the case of pipelines transporting natural gas liquid (NGL), a ½ mile buffer was used to determine those segments which could affect HCAs. The ½ mile buffer was not supported in Enbridge's process by adequate technical justifications. In order to support the determination of an adequate buffer zone for NGL pipelines, OPS proposes that your process be modified to include a technical analysis of the predicted vapor dispersion due to a leak of the NGL's transported in your system.

Enbridge Response to Comment C):

Fortunately our system has had little experience with NGL releases. Upon review of the six NGL releases on file, the average overland vapor transport (advection and dispersion) was approximately 300 feet, with the maximum radial distance of 1,100 feet. Given the small data set, a high confidence that these transport distances were representative of the system as a whole could not be achieved. As such, a more conservative approach was adopted. We defaulted to the 0.5-mile Evacuation Perimeter set forth in the DOT's Emergency Response Guidebook for flammable gas releases (ERG115). The DOT developed this perimeter using a much more extensive data set for flammable gas releases. As such we have a high degree of confidence using this perimeter, and do not plan to revisit our initial analysis at this time. However, a case history of Enbridge system NGL releases will be incorporated in the Plan for informational purposes.

In summary, the basis for some of our analyses (actual events on our system) was communicated verbally or graphically (via our GIS) during the February 2002 audit and was not in our Plan. Much of this information has, or will be, formally documented in our Plan.

As stated earlier, we have made a good faith effort and complied with the intent the Rule prior to the audit. We have also taken your comments to heart in the manner detailed above, and will modify our Plan accordingly. Please do not hesitate to call me if you have any comments or questions. I can be reached at (218) 725-0505.

Sincerely,

John R. Sobojinski

BP/pb
Attachment – May 15, 2002 letter

c: John Hayes
Joel Kanvik
Greg Sevick
Dan Tutcher

Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

September 3, 2002

UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
901 Locust St., Room 462
Kansas City, MO 64106

Re: CPF No. 3-2002-5008-M

Dear Mr. Huntoon:

This submittal serves to amend our June 18, 2002 letter detailing our response to the above-referenced issue. In particular, our response to comment C in the OPS Notice of Amendment has been modified as follows:

OPS Comment C):

In the case of pipelines transporting natural gas liquid (NGL), a ½ mile buffer was used to determine those segments which could affect HCAs. The ½ mile buffer was not supported in Enbridge's process by adequate technical justifications. In order to support the determination of an adequate buffer zone for NGL pipelines, OPS proposes that your process be modified to include a technical analysis of the predicted vapor dispersion due to a leak of the NGL's transported in your system.

Enbridge Response to Comment C):

An analysis of the advection and dispersion of NGL potentially released from our pipelines will be performed and compared with the half-mile buffer approach used during our HCA pipe segment identification process, and our procedures will be modified accordingly.

Please do not hesitate to call me at the above telephone number if you have any comments or questions.

Sincerely,

John R. Sobojinski

BFP/pb

c: John Hayes
Joel Kanvik
Greg Sevick
Dan Tutcher

U.S. Department of Transportation
Research and Special Programs Administration

400 Seventh Street, S.W.
Washington, D.C. 20590

DEC - 3 2002

Mr. Daniel C. Tutcher
President
Enbridge Energy Company, Inc.
1100 Louisiana Street
Suite 3300
Houston, TX 77002-5217

Re: CPF No. 3-2002-5008M

Dear Mr. Tutcher:

Enclosed is the Order Directing Amendment issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It makes a finding of inadequate procedures and requires that you amend your integrity management program procedures. When the terms of the Order are completed, as determined by the Director, Central Region, OPS, this enforcement action will be closed. Your receipt of the Order Directing Amendment constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

Gwendolyn M. Hill

Gwendolyn M. Hill
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: John R. Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
Enbridge Energy Company, Inc.	)	CPF No. 3-2002-5008M
	)	
Respondent.	)	
	)	

ORDER DIRECTING AMENDMENT

On February 26-27, 2002, pursuant to 49 U.S.C. § 60117, representatives of the Central and Eastern Regions, Office of Pipeline Safety (OPS), inspected Enbridge Energy Company's (Respondent's) integrity management program at Respondent's facility in Duluth, Minnesota. As a result of the inspection, the Central Regional Director, OPS, issued to Respondent, by letter dated May 15, 2002, a Notice of Amendment (NOA). The NOA alleged inadequacies in Respondent's integrity management program and proposed to require amendment of Respondent's procedures to comply with the requirements of 49 C.F.R. § 195.452(b).

Respondent responded to the NOA by letter dated June 18, 2002, as supplemented by letter dated September 3, 2002. Respondent did not contest the allegations set forth in the NOA and did not request a hearing, consequently Respondent waived its right to one. However, Respondent described the actions it is taking to address the inadequacies in its procedures that were identified in the NOA.

Accordingly, I find that Respondent's integrity management program procedures are inadequate to ensure safe operation of its pipeline system. Pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237, Respondent is ordered to make the following changes to its integrity management program procedures. Respondent must:

1. Amend its procedures to provide adequate technical justification for determining the spill volume used to identify pipeline segments that could affect high consequence areas accounting for Respondent's leak history which includes incidents larger than the 20,000 barrel volume used in its original analysis;

2. Amend its procedures to modify the land flow analysis used to identify pipeline segments that could affect high consequence areas to account for topographical gradients and other factors that could stretch the spill plume geometry beyond the 1,770 feet associated with uniform distribution over a strophoid shaped plume;

3. Amend its procedures to provide adequate technical justification for determining the extent of the buffer zone used to identify natural gas liquid pipeline segments that could affect high consequence areas to include an analysis of predicted vapor dispersion from a natural gas liquid release;

4. Respondent must amend its procedures within 30 days following receipt of this Order Directing Amendment. Submit all amended procedures and technical justifications demonstrating compliance with this Order to the Director, Central Region, Office of Pipeline Safety, 901 Locust Street, Suite 462, Kansas City, MO 64106-2641.

The Director, Central Region, OPS, may grant an extension of time to comply with any of the required items upon a request by the Respondent demonstrating good cause for an extension.

Failure to comply with this Order Directing Amendment may result in the assessment of civil penalties of up to $25,000 per violation per day, or in the referral of the case for judicial enforcement. The terms and conditions of this Order are effective upon receipt.

James K O'Steen

for Stacey Gerard
Associate Administrator
for Pipeline Safety

DEC - 3 2002

Date Issued

Enbridge Pipelines (Lakehead) L.L.C.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

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January 9, 2003

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5008M

We received an Order Directing Amendment issued by the Associate Administrator for Pipeline Safety in the above-referenced case on December 16, 2002. We respectfully request a 60-day extension in which to respond to this Order.

Sincerely,

John R. Sobojinski

c: John Hayes
Joel Kanvik
Greg Sevick
Dan Tutcher

Enbridge Pipelines (Lakehead) L.L.C.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
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Tel 218 725 0505
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john.sobojinski@enbridge-us.com

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JAN 2 2 2003

January 14, 2003

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5008M

This is in response to my conversation with Dave Barrett on Friday, January 10, 2003, and his clarification of specific information required to be submitted to the OPS in order to comply with the above-named Order. The information that we provided to you in our June 18 and September 3, 2002 letters appropriately addressed the concerns raised by OPS. This same information was targeted for inclusion in our Integrity Management Program manual, which we are currently in the process of updating. We will provide copies of these specific procedures to you by no later than January 31, 2003. We will, therefore, not require the 60-day extension initially requested in our January 9, 2003 letter.

I trust this is acceptable to the OPS. If you have any questions in the interim, please contact me.

Sincerely,

John R. Sobojinski

c: John Hayes
~~Gwendolyn Hill, OPS~~
Joel Kanvik
Greg Sevick
Dan Tutcher

I

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

January 24, 2003

Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

Re: CPF No. 3-2002-5008M
Request for Extension of Time

Dear Mr. Sobojinski:

The Office of Pipeline Safety has received your letters of January 9, 2003, and January 14, 2003, requesting an extension of time to comply with the Order Directing Amendment referenced above. Your January 14, 2003, correspondence indicated that Enbridge did not require a 60-day extension as originally requested on January 9, 2003. Your request has been reviewed, and I am granting an extension of time to submit the required procedures to the Central Region Office by no later than January 31, 2003, as stated in your request of January 14, 2003.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enbridge Pipelines (Lakehead) L.L.C.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

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January 30, 2003

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

DOT-RSPA-OPS '03 JAN 31 AM 11:15

Dear Mr. Huntoon:

CPF No. 3-2002-5008M – Order Directing Amendment

In response to your "Order Directing Amendment", dated December 3, 2002, attached is a document which details portions of our integrity management program. Specifically, the information identifies pipeline segments which may impact an HCA. Following are our responses to those items addressed in the "Order Directing Amendment":

Item 1. Amend its procedures to provide adequate technical justification for determining the spill volume used to identify pipeline segments that could affect high consequence areas accounting for Respondent's leak history which includes incidents larger than the 20,000 barrel volume used in its original analysis.

Enbridge Response to Item 1. The technical justification for volume-out calculations is given in Tab 4, Appendix D, of our Integrity Management Plan, and is provided here as an attachment. The segment identification process, using stationing specific volume out, is discussed through the text portion of the attached report, as it affects transport via overland flow and NGL dispersion, with technical details provided in Appendix A.

Item 2. Amend its procedures to modify the land flow analysis used to identify pipeline segments that could affect high consequence areas to account for topographical gradients and other factors that could stretch the spill plume geometry beyond the 1,770 feet associated with uniform distribution over a strophoid shaped plume.

Enbridge Response to Item 2. Relating to topographic channeling, we have formulated the strophoid geometry to be terrain dependent. Stretching factors to modify plume geometry as a function of the general topographic expression have been developed in a manner consistent with the gradient-based approach developed to analyze the potential transport of oil on water. A discussion on the approach is given in Section I.C., with technical detail provided in Appendix A.

Item 3. Amend its procedures to provide adequate technical justification for determining the extent of the buffer zone used to identify natural gas liquid pipeline segments that could affect high consequence areas to include an analysis of predicted vapor dispersion from a natural gas liquid release.

Enbridge Response to Item 3. As with overland flow and spray zone analysis, the actual release history of our system was taken into account while formulating a model to predict the dispersion of NGLs from a potential release. A discussion on the approach is given in I.4., with technical detail provided in Appendix A.

Please do not hesitate to call me directly if you have any comments or questions. I can be reached at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: John Hayes
Gwendolyn Hill, OPS
Joel Kanvik
Greg Sevick
Dan Tutcher

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 21, 2007

Mr. Terrance McGill
President
Enbridge Pipelines, LLC
1100 Louisiana
Suite 3000
Houston, TX 77002

CPF 3-2002-5008-M

Dear Mr. McGill:

On February 26 – 27, 2002, representatives from the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of Enbridge Pipelines, LLC's (Enbridge) integrity management segment identification procedures in Duluth, Minnesota. As a result of the inspection, Enbridge was issued an Order Directing Amendment on December 3, 2002, which required amendment of your procedures.

Enbridge submitted its amended procedures on January 30, 2003. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Order Directing Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

①

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 5, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5014W

Dear Mr. Tutcher:

On May 7 - May 18, 2001 and June 11 - June 12, 2001, a representative of the Central Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your records for the Lakehead pipeline (LPL) at Bay City, MI; Escanaba, MI; Ironwood, MI and Duluth, MN locations and field facilities located within the states of Michigan and Wisconsin.

As a result of the inspection, it appears that you have committed probable violations as noted below of pipeline safety regulations Title 49, Code of Federal Regulations, Part 195.

The items inspected and the probable violations are:

1. **§ 195.222 Welders: Qualification of welders.**

   Each welder must be qualified in accordance with Section 3 of API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not requalify under that earlier edition.

At the Ironwood PLM Office, review of the Welder Qualification Record for Mr. Russell A. Paquette indicated that Mr. Paquette did not follow Welding Procedure Specification (WPS) UF-28 when taking the welder qualifying test on 03/06/2000.

2. **§ 195.410 Line markers.**

§ 195.410(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

§ 195.410(a)(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

§ 195.410(a)(2) The marker must state at least the following:
"Warning" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline" (in lettering at least 1 inch high with an approximate stroke of one-quarter inch on a background of sharply contrasting color), the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

a. LPL's markers displayed an incorrect company contact number or were missing a contact number at the following locations:

i) MP1222.048 (markers on each side of road)
ii) MP1238.153 (markers on each side of road)

b. LPL's marker was missing at the following location:

i) MP 1393.759 Indian River - East Side

3. **§ 195.434 Signs.**

Each operator shall maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and an emergency telephone number to contact.

a. LPL's signs displayed an incorrect company contact number or were missing a contact number at the following locations:

- i) M/L Valve at MP1105.98
- ii) M/L Valve at MP1115.55
- iii) M/L Valve at MP1127.69
- iv) M/L Valve at MP1173.20
- v) M/L Valve at MP1183.78
- vi) M/L Valve at MP1212.18
- vii) M/L Valve at MP1299.72

b. LPL's signs were missing at the following locations:

- i) M/L Valve at MP1307.35
- ii) M/L Valve at MP1343.70
- iii) M/L Valve at MP1396.39

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $25,000 for each violation for each day the violations persist up to a maximum of $500,000 for any related series of violations.

We have reviewed the circumstances and supporting documents involved in this case, and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations, we will take enforcement action when and if the continued violations come to our attention.

You will not hear from us again with regard to the noted inspection and our subsequent action. Because of the good faith that you have exhibited up to this time, we expect that you will act to bring your pipeline operations into compliance with pipeline safety regulations.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

Phil

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September 16, 2002

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5014W

In response to your Warning Letter to Enbridge dated June 5, 2002, I confirm that all identified areas of probable violation have been addressed and corrected. We appreciate the fact that no civil penalty was assessed. The items in question were initially identified during the May-June 2001 audits; therefore, many of them had already been corrected. We have gathered evidence of appropriate completion for each item listed in your letter, and have detailed supporting documents on file in our Duluth Office.

If you should have any further questions or concerns about any of the items referenced in your letter, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment – Warning Letter
c/att: John Hayes
Greg Sevick
Tom Fridel
Mark Sitek
Dan Tutcher
Law Department

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
AND
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 5, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5015

Dear Mr. Tutcher:

During May 7 - May 18, June 11 - 22 and August 27, 2001, representatives of the Central Region Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted onsite pipeline safety inspections of your Lakehead pipeline (LPL)facilities and records at Duluth, MN (records); Bay City, MI (records); Griffith, IN (records); Fort Atkinson, WI (PLM records); Ironwood, MI (PLM records); Escanaba, MI (records); Superior, WI (records); States of Michigan, Indiana, Illinois and Wisconsin (field facilities).

As a result of the inspections, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1. **§ 195.310 Records.**
§ 195.310(b) The record required by paragraph (a) of this section must include:

§ 195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The pressure test records for Line #17 (Stockbridge, MI to Freedom Junction, MI) did not contain a profile of the line although there are elevation differences that exceed 100 feet along the route for Line #17 (Crude System #3).

2. **§ 195.432 Inspection of in-service breakout tanks.**

§ 195.432(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.

During the records review at Bay City, MI it was observed that LPL did not have documentation for annual tank inspections for the Stockbridge, MI station for the year 2000 (Crude System #3).

3. **§ 195.401 (b) General requirements.**

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

During the field inspection it was observed that the view of LPL's right-of-way was obstructed at the following locations:

a. MP1164.60 - west side (Crude System #2)
b. MP1238.153 (Crude System #2)
c. MP1247.89 (Crude System #2)
d. MP1260.166 - west side (Crude System #2)
e. MP1280.307 - west side (Crude System #2)
f. MP1387.577 - east side (Crude System #2)
g. MP1429.301 - west side (Crude System #2)
h. MP1439.71 - Black River crossing (both sides) (Crude System #2)
i. MP1460.187 (Crude System #2)
j. MP1465.50 - east side (Crude System #2)
k. MP 515.100 (Line 6B) - east side of the road (Crude System #3)
l. MP 383.090 (Line 6A) Dundee Station - due north and south from the mainline valve located outside the station fencing (Crude System #3)

Right-of-way inspections conducted by the operator under § 195.412(a) should have noted that an aerial view of the right-of-way was obstructed by overgrowth.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $25,000 for each violation for each day the violations persist up to a maximum of $500,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and it is her recommendation that you be preliminarily assessed a civil penalty as follows:

Item 1 -	$ 5,000
Item 2 -	$ 5,000
	$10,000.

Additionally, pursuant to 49 United States Code § 60118, the Office of Pipeline Safety proposes to issue to you a compliance order with respect to Item 3. That proposed compliance order is attached to and made a part of this Notice of Probable Violation.

Also, attached to and made a part of this Notice is a description of the available procedures for responding to this Notice. Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights under 49 CFR 190.209. No response or a response which does not contest the allegations in the Notice authorizes the Associate Administrator for Pipeline Safety to find the facts to be as alleged herein and to issue appropriate orders. The 30 day period for response may be extended for good cause shown, and submitted within the original 30 day period.

Please refer to CPF No. 3-2002-5015 in any correspondence or communication on this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enclosures

cc: Mr. John Sobojinski (w/Enclosure)
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Office of Pipeline Safety proposes to issue to Enbridge (Lakehead Pipeline) a compliance order incorporating the following requirements to assure compliance with the pipeline safety regulations applicable to its operations.

In regard to Item No. 3 of the Notice pertaining to the obstruction of the view of Enbridge's (Lakehead Pipeline) right-of-way at various locations:

1. Develop a plan and corresponding time schedule for the removal and/or the clearing of the obstructions that hinder the view of the right-of-way.

2. Prepare appropriate remediation plans for the removal/clearing of the obstructions that hinder the view of the right-of-way. The plans, including a proposed schedule, are to be submitted to the Director, Central Region, Office of Pipeline Safety, 901 Locust Street, Suite 462, Kansas City, Missouri 64106.

   This item is to be completed within 90 days following your receipt of the Final Order.

3. Submit quarterly progress reports to the Director, Central Region, Office of Pipeline Safety, 901 Locust Street, Suite 462, Kansas City, Missouri 64106.

   This item shall begin when Enbridge (Lakehead Pipeline) commences the plan for removing/clearing the obstructions that hinder the view of the right-of-way.

4. When appropriate actions have been completed in regard to the above items in this Compliance Order, submit copies of the final completed schedule and notice of completed actions to the Director, Central Region, Office of Pipeline Safety, 901 Locust Street, Suite 462, Kansas City, Missouri 64106.

UNITED STATES DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY

HAZARDOUS LIQUID PIPELINE SAFETY VIOLATION REPORT

1. **Inspector Name:**	2. **Date of Inspection:**	3. **CPF #:**
Phil Archuletta	6/11/01 - 6/22/01	3-2002-5015

4. Pipeline Operator/Owner:

Lakehead Pipe Line Company Inc. (now called Enbridge Energy Company, Inc.)

5a. **Headquarters Address:**	5b. **Telephone No.:**
1100 Louisiana, Suite 2950 Houston, TX. 77002	713-650-8900

6. **Inspection Location:**	7. **Inspection Unit No.:**
Escanaba, MI and Bay City, MI	#153 Crude System #2 and #423 Crude System #3

8. Portion of System Inspected:

Records at Escanaba, MI. Pipeline facilities and records from the US/Canadian border near Marysville, MI southwesterly to Chicago then northwesterly to Superior, WI.

9. Nature and Size of System:

Number of Miles Approximately 684 total pipeline miles. (Crude System #2)
Approximately 1,242 total pipeline miles. (Crude System #3)
Refer to attached Lakehead Pipe Line System Map; Item No. 8.

Commodities Crude Oil

Relevant details with Respect to System Crude System #2: From MP 97.23 (Hwy 8 - Centerline) north of the Ladysmith, WI station to Superior, WI to the Lewiston, MI station through UP Michigan.

Crude System #3: Lines from the Canadian border near Marysville, MI. to Griffith, IN and then north to Superior, WI and from Stockbridge, MI to Freedom Junction, MI.

10. Nature of Probable Violations:

___ 1. Problem in Design/Materials
___ 2. Problem in Construction
___ 3. Reporting Requirements
___ 4. Test Requirements
___ 5. Personnel Qualifications and Training
___ 6. Anti-drug Program
___ 7. Other Operations
___ 8. Corrosion Control
___ 9. Pressure Control
X 10. Other Maintenance/Monitoring

11. Inadequate Procedures
___ A. Construction
___ B. Corrosion Control
___ C. Operations
___ D. Training
___ E. Maintenance

Violation No.: 1

11a. **CFR § Violated:**

§ 195.310 Records.

11b. **Summarize what the regulations require that the operator did not do:**

§ 195.310(b) The record required by paragraph (a) of this section must include:

§ 195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The operator's test records did not contain a pipeline profile as required by § 195.310(b)(9).

12. **Provide detailed information about violation:**

Lakehead Pipe Line's pressure test records for Line #17 (Stockbridge, MI to Freedom Junction, MI) did not contain a profile of the line as required by §195.310(b)(9) although there are elevation differences that exceed 100 feet along the route for Line #17. Line#17 was constructed between November, 1998 and February, 1999. The pressure test was conducted in line sections and the section tests were conducted November 27, 1998; December 9, 1998 and January 5 through 7, 1999. The pressure tests were used to establish the initial integrity of the line and to establish the maximum operating pressure (MOP) of the line (Crude System #3).

Items No. 1 and 2 are provided to show that there is at least 100 feet elevation difference along the pipeline route.

Violation No.: 1 (cont.)

13. **Public and/or environmental concerns in area of violation:**

Failure of the pipeline could cause personal injury, property damage and /or environmental damage. The pipeline crosses public roads, highways, streams and passes near small rural towns.

14a **Person Interviewed**	**Title:**
Doug Klein	Safety & Compliance
Jay Johnson	Operations Services Coordinator
John Klarich	PLM Supervisor
Marc Curry	Safety & Compliance

14b **Comments of person interviewed:**

The persons interviewed during the records review were not able to explain why a profile of the pipeline was not included in the pressure test records for Line #17.

Violation No.: 2

11a. CFR § Violated:

§ 195.401 (b) General requirements.

11b. Summarize what the regulations require that the operator did not do:

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

An adverse condition existed that was not corrected in a reasonable time. Right-of-way in several areas had not been cleared so that it could be adequately observed by aerial patrol.

12. Provide detailed information about violation:

During the field inspection it was observed Lakehead Pipeline's right-of-way was obstructed from aerial view at the following locations:

a. MP1164.60 - west side (Crude System #2)
b. MP1238.153 (Crude System #2)
c. MP1247.89 (Crude System #2)
d. MP1260.166 - west side (Crude System #2)
e. MP1280.307 - west side (Crude System #2)
f. MP1387.577 - east side (Crude System #2)
g. MP1429.301 - west side (Crude System #2)
h. MP1439.71 - Black River crossing (both sides) (Crude System #2)
i. MP1460.187 (Crude System #2)
j. MP1465.50 - east side (Crude System #2)
k. MP 515.100 (Line 6B) - east side of the road (Crude System #3)
l. MP 383.090 (Line 6A) Dundee Station - due north and south from the mainline valve located outside the station fencing (Crude System #3)

Right-of-way inspections conducted by the operator under § 195.412(a) should have noted this need for right-of-way clearing. Since the aerial patrol pilot cannot see through the overgrowth, the pilot is not adequately able to "inspect the surface conditions on or adjacent to each pipeline right-of-way". LPL does not use ground patrols in the two areas listed above and relies solely on aerial patrols for these areas.

Items No. 3, 4 and 5 are provided to show the extent of the obstruction of the operator's right-of-way by overgrowth.

Violation No.: 2 (cont.)

13. **Public and/or environmental concerns in area of violation:**

Aerial patrol pilots must have an unobstructed view of the ground conditions immediately above and adjacent to a pipeline in order to see visual signs of items that may indicate that the integrity of the pipeline has been compromised. Early detection of a possible pipeline problem is important toward minimizing the affect a pipeline release would have on the public, property and the environment. The line crosses a secondary road near the Dundee Pump Station and the line is within 30 feet to 50 feet of a overhead main transmission power line. This proximity to the power line could pose a fire risk if there was a release from the pipeline that was not detected in a timely manner.

14a. Person Interviewed	Title:
Doug Klein	Safety & Compliance
Jay Johnson	Operations Services Coordinator
John Klarich	PLM Supervisor
Marc Curry	Safety & Compliance

14b **Comments of person interviewed:**

The persons interviewed during the records review indicated they understood the importance of keeping pipeline right-of-ways clear for adequate observation by an aerial patrol pilot.

Violation No.: 3

11a. CFR § Violated:

§ 195.432 Inspection of in-service breakout tanks.

11b. Summarize what the regulations require that the operator did not do:

The operator did not inspect breakout tanks at least once in a calendar year as required by § 195.432(a) of the regulations.

12. Provide detailed information about violation:

During the records review at Bay City, MI it was observed that Lakehead Pipeline did not have documentation for annual tank inspections for the Stockbridge, MI station for the year 2000. The operator confirmed that the tank inspections were not conducted (refer to details in item 14b). (Crude System #3).

Records are available for the 2001 inspections performed.

Items No. 6 and 7 contain the tanks in this inspection group. There are 2 tanks.
Items No. 6 and 7 are provided to identify which tanks are involved and to provide an example of the type of inspection that was not conducted.

Violation No.: 3 (cont.)

13. **Public and/or environmental concerns in area of violation:**

The concern is the potential for a release of crude oil from a storage tank that could impact operator personnel, public personnel, the environment and/or property. Periodic inspections are required to ensure the integrity of the tank and minimize the risk of a possible release of crude oil.

14a. **Person Interviewed** / **Title:**

Person Interviewed	Title
Doug Klein	Safety & Compliance
Jay Johnson	Operations Services Coordinator
John Klarich	PLM Supervisor
Marc Curry	Safety & Compliance

14b. **Comments of person interviewed:**

The persons interviewed during the records review stated that the tanks were placed in service in April of 1999 thus the first annual inspection should have been in calendar year 2000. The persons interviewed stated that due to confusion over who was to actually complete the inspections, the inspections were not conducted. The inspections were then completed properly for calendar year 2001.

15. Supporting Documents/Materials:

Item No.	Description	Source of Document	Remarks
1	Hydrostatic Test Report; Enbridge Pipelines (Toledo) Inc.; January 05, 1999 through January 07, 1999 (3 pages)	Lakehead	
2	Hydrostatic Test Report; Enbridge Pipelines (Toledo) Inc.; November 27, 1998 and December 09, 1998 (3 pages)	Lakehead	
3	Photo of Lakehead right-of-way near Dundee , IL station; PHOTO #1	OPS Inspector	
4	Photo of Lakehead right-of-way near Dundee , IL station; PHOTO #2	OPS Inspector	
5	Photo of Lakehead right-of-way near Dundee , IL station; PHOTO #3	OPS Inspector	
6	Annual Tank Inspection Report; Tank No. 80; Date: 6/4/2001; Station/Terminal: Stockbridge	Lakehead	
7	Annual Tank Inspection Report; Tank No. 81; Date: 6/4/2001; Station/Terminal: Stockbridge	Lakehead	
8	Lakehead System Map	Lakehead	
9	Oil & Gas Journal Table of Oil Pipelines; Sept. 3, 2001	Oil & Gas Journal	

16. Inspector's Signature **Date:**

Phil Archuletta 5/31/02

17. Compliance History:

Date	Place	Describe Violation/Noncompliance	CPF No.	Outcome
06/25/87		§ 195.406	31987X547	NPV & PCP
07/25/89		§ 195.420	31989X561	NPV & PCP
12/17/90		§ 195.402	319905004	NOA
02/26/01		Issue concerning ROW clearing	320015003C	LOC

18. Gravity of Offense:

Violation 1: All parameters are important in conducting a hydrostatic test of a pipeline and elevation differences are one of the parameters used to determine if target test pressures are being maintained at all points along the pipeline route.

Violation 2: During an aerial patrol of an operator's right-of-way, it is important that the pilot have an unobstructed view of areas directly above and adjacent to pipelines in order to check for visual indications of a possible pipeline release or to check for activities on/near the right-of-way that may effect the integrity of the pipeline.

Violation 3: The reliable integrity of storage tanks is important to ensure that there is not a release of crude oil resulting from a tank structural and/or mechanical failure. Tanks must be inspected on a regular basis to ensure that the tanks are in sound condition.

19. Degree of Culpability:

The operator is aware of the subject regulations and the need for properly conducting pressure tests, ensuring that the operator's pilot can observe the right-of-way clearly and conducting inspections of storage tanks per regulation requirements.

20. Ability to Continue in Business:

The proposed penalty should not affect Lakehead Pipeline's ability to conduct normal business operations. Item Exhibit #9 is provided for inclusion of information indicating the size of their facilities and their delivery capacity.

21. Ability to Pay:

Lakehead Pipeline should be able to pay the assessed penalty.

22. Good Faith in Attempting to Achieve Compliance:

Lakehead Pipeline has been very cooperative in the past on resolving regulation compliance and safety issues.

23a. Proposed Remedy:

____ **Warning Letter**

X **Civil Penalty:** **Recommended** **$ 10,000**

X **Compliance Order**

____ **Hazardous Facility Order**

____ **Notice of Amendment of O&M Plan**

23b. Analysis of Proposed Remedy:

Lakehead Pipeline understands regulation requirements. Lakehead Pipeline plans to remind personnel of the importance of accurate record keeping, proper facility maintenance and completing inspections in a timely manner and per regulation requirements. The proposed penalty should be adequate to ensure that Lakehead Pipeline complies with the specific pipeline safety regulations cited.

24. Region Chief's Signature: **Date:**

Ivan A. Huntoon 6/4/02

HYDROSTATIC TEST REPORT

ENBRIDGE PIPELINES (TOLEDO) INC.

13.37 MILES OF 16" O.D. X.250 W/T, X-70 CRUDE OIL PIPELINE
STA. NO. 493+25 TO STA. NO. 1199+00
TEST NO. 17-98-65 (B)
213 FT. OF 16" O.D. X.281 W/T. X-70 PIPE
STA. NO. 1199+00 TO STA. NO. 1861+22
TEST NO. 17-98-66 (C)

JANUARY 05, 1999 THROUGH JANUARY 07, 1999

Universal Hydrotesting Company
P.O. Box 218
8350 Huttenlocker
Munith, MI 49259

Phone: (517) 596-2629

Test Section B

Interprovincial Pipe Line Inc.
Lakehead Pipe Line Company, Inc.

PRESSURE TEST REPORT

PROJECT/AFE Line 17 Construction AFE 98401

TEST REPORT NO. 17-98-65 (B) Page 1 of 3 TEST DATE 1-5-99

PIPELINE CONTRACTOR Coilsaet Construction Co.

TESTING CONTRACTOR Universal Hydrotest

DESCRIPTION OF FACILITY ☑ MAINLINE LINE NO. 17 FROM ~~MP~~ STA 1493+25 TO ~~MP~~ STA 1199+00

☐ STATION PIPING STATION

☐ EMERGENCY STOCK PIPE PIPE ID

☐ DRAWING ATTACHED NO.

PIPE DATA

OD	WT	Grade	Length	Manufacturer	Type
16"	.281	X70	8,224'	U.S.S.	ERW
16"	.375	X60	204'		
16"	.250	X70	62033'	USS	ERW

TEST DATA

TEST MEDIUM Water FILL VOLUME: SQUEEZE VOLUME:

Test	Aim Test Pressure	Minimum	Maximum	Duration, h
Strength	2096 psi	2081 psi	2093 psi	4hr
Leak	2096	"	"	4hr

MAINLINE USE ONLY

Deadweight/Recorder Elev. 927 ft.	Location 1199+00	Pressure 2096 psig
High Point Elevation 1036 ft.	Location 1013+20	Pressure 2049 psig
Low Point Elevation 848 ft.	Location 740+00	Pressure 2130 psig

	REFERENCE INSTRUMENTS		TEST EQUIPMENT		Pipe
	Deadweight Pressure	Liquid in Glass Thermometer	Pressure Recorder	Pressure Gauge	Temperature Recorder
Make	Chandler	Miccenta	Barton	Wika	Barton
Range	50-3,000		0-3,000	0-3,000	0°-150°F
Serial No.	23387	none	53231	none	53225

	Calibration Before Test			Calibration After Test			
	¼ Scale	½ Scale	Full Scale	Full Scale	½ Scale	¼ Scale	Zero
Deadweight	271	1260	2087	2081	1070	545	
Pressure Recorder	271	1250	2070	2060	1075	545	
Pressure Gauge	275	1245	2050	2050	1060	550	

See Accompanying Pages for Pressure and Temperature Records

S. Rew

Contractor Representative [signature] Company Representative [signature]

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Test Section C

Interprovincial Pipe Line Inc.
Lakehead Pipe Line Company, Inc.

PRESSURE TEST REPORT

PROJECT/AFE IPL Toledo AFE 98-401

TEST REPORT NO. 17-98-66(c) Page 1 of 3 TEST DATE 1-6-99

PIPELINE CONTRACTOR RL Coolsaet

TESTING CONTRACTOR Universal Hydrotest

DESCRIPTION OF FACILITY ☒ MAINLINE LINE NO. 17 FROM ~~MP~~ STA 1199+00 TO ~~MP~~ STA 1861+22

☐ STATION PIPING STATION

☐ EMERGENCY STOCK PIPE PIPE ID

☐ DRAWING ATTACHED NO.

PIPE DATA

OD	WT	Grade	Length	Manufacturer	Type
16"	.281	X70	3943'	USS	ERW
16"	.375	X 60	250'	USS	ERW
16"	.250	X.70	61,029'	USS	ERW

TEST DATA

TEST MEDIUM Water FILL VOLUME: SQUEEZE VOLUME:

Test	Aim Test Pressure	Minimum	Maximum	Duration, h
Strength	2087 psi	2068 psi	2078 psi	8 hrs
Leak				

MAINLINE USE ONLY

Deadweight/Recorder Elev. ~~1199~~ 927 ft. Location 1199+00 Pressure 2087 psig

High Point Elevation 979 ft. Location 1750+00 Pressure 2064 psig

Low Point Elevation 825 ft. Location 1568+00 Pressure 2131 psig

	REFERENCE INSTRUMENTS		TEST EQUIPMENT		
	Deadweight Pressure	Liquid in Glass Thermometer	Pressure Recorder	Pressure Gauge	Temperature Recorder
Make	Chandler	Micronta	Barton	Wika	Barton
Range	50-300		0-3000	0-3000	0°-150°
Serial No.	23387	none	53231	none	55735

	Calibration Before Test			Calibration After Test			
	¼ Scale	½ Scale	Full Scale	Full Scale	½ Scale	¼ Scale	Zero
Deadweight	625	1250	2080	2068	1200	620	100
Pressure Recorder	625	1250	2080	2060	1200	620	100
Pressure Gauge	620	1240	2050	2060	1190	620	110

See Accompanying Pages for Pressure and Temperature Records

Contractor Representative Dennis Potter Company Representative John Klaviel D. Rew

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ENG 36A/12/93

HYDROSTATIC TEST REPORT

ENBRIDGE PIPELINES (TOLEDO) INC.

9.34 MILES OF 16" O.D. X.281 W/T, X-70 CRUDE OIL PIPELINE
STA. NO. 7+93 TO STA. NO. 493+39
TEST NO. 17-98-64 (A)
213 FT. OF 16" O.D. X.281 W/T. X-70 PIPE
STA. NO. 5+80 TO STA. NO. 7+93
TEST NO. 17-98-63 (A-1)

NOVEMBER 27, 1998 AND DECEMBER 09, 1998

Universal Hydrotesting Company
P.O. Box 218
8350 Huttenlocker
Munith, MI 49259

Phone: (517) 596-2629

Item No. 2

Interprovincial Pipe Line Inc.
Lakehead Pipe Line Company, Inc.

PRESSURE TEST REPORT

PROJECT/AFE: IPL Toledo AFE 98-401

TEST REPORT NO. 17-98-63 Page 1 of 3 TEST DATE 11-27-98

PIPELINE CONTRACTOR RL Coolsaet

TESTING CONTRACTOR Universal Hydrotesting

DESCRIPTION OF FACILITY ☒ MAINLINE LINE NO. 17 FROM MP 5+80 TO MP 7+93

☐ STATION PIPING STATION

☐ EMERGENCY STOCK PIPE PIPE ID

☐ DRAWING ATTACHED NO.

PIPE DATA

OD	WT	Grade	Length	Manufacturer	Type
16"	.281	X 70	213'3"	USS	API 5L

TEST DATA

TEST MEDIUM Water FILL VOLUME: SQUEEZE VOLUME:

Test	Aim Test Pressure	Minimum	Maximum	Duration h
Strength		2443	2459	4 hr
Leak		2443	2459	4 hr

MAINLINE USE ONLY

Deadweight/Recorder Elev. ft Location Pressure psig

High Point Elevation ft Location Pressure psig

Low Point Elevation ft Location Pressure psig

	REFERENCE INSTRUMENTS		TEST EQUIPMENT		Pipe
	Deadweight Pressure	Liquid in Glass. Thermometer	Pressure Recorder	Pressure Gauge	Temperature Recorder
Make	Chandler		Barton		Barton
Range	50-3000		0-3000		0-150
Serial No.	23385		53231		53225

	Calibration Before Test			Calibration After Test			
	¼ Scale	½ Scale	Full Scale	Full Scale	½ Scale	¼ Scale	Zero
Deadweight							
Pressure Recorder							
Pressure Gauge							

See Accompanying Pages for Pressure and Temperature Records

Contractor Representative Dennis Potter Company Representative Bruce MacDonald

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Interprovincial Pipe Line Inc.
Lakehead Pipe Line Company, Inc.

PRESSURE TEST REPORT

(AFE) 98-401

REPORT NO. 17-98-64 (A) Page 1 of 4 TEST DATE 12-9-98

CONTRACTOR R.L. Coolsaet Const. Co.

TESTING CONTRACTOR Universal Hydro Test

DESCRIPTION OF FACILITY ☑ MAINLINE LINE NO. 17 FROM ~~MP~~ STA. 7+93 TO ~~MP~~ STA. 493+39

☐ STATION PIPING STATION

☐ EMERGENCY STOCK PIPE PIPE ID

☐ DRAWING ATTACHED NO.

PIPE DATA

OD	WT	Grade	Length	Manufacturer	Type
16"	.281	X-70	485+46	U.S.S	API 5L

TEST DATA

TEST MEDIUM WATER FILL VOLUME: 489,000 GAL SQUEEZE VOLUME: from 167 psi 2,536 gal. from 1390 psi 1960 gal.

Test	Aim Test Pressure	Minimum	Maximum	Duration, h
Strength	2,317			
Leak				

MAINLINE USE ONLY

Deadweight/Recorder Elev. 992 ft. Location 493+39 Pressure 2317 psig

High Point Elevation 956 ft. Location 464+00 Pressure 2307 psig

Low Point Elevation 871 ft. Location 430+00 Pressure 2344 psig

	REFERENCE INSTRUMENTS		TEST EQUIPMENT Piping		
	Deadweight Pressure	~~Liquid-in-Glass~~ Electronic Thermometer	Pressure Recorder	Pressure Gauge	Temperature Recorder
Make	Chandler	Micronta	Barton	Wikka	Barton
Range	50-3,000		0-3000	0-3000	
Serial No.	23385	—	53231	#8 —	49923

	Calibration Before Test			Calibration After Test			
	¼ Scale	½ Scale	Full Scale	Full Scale	½ Scale	¼ Scale	Zero
Deadweight				2305	1206	595	0
Pressure Recorder				2300	1200	595	0
Pressure Gauge				2260	1200	600	0

See Accompanying Pages for Pressure and Temperature Records

Contractor Representative Dennis Potter Company Representative D. New

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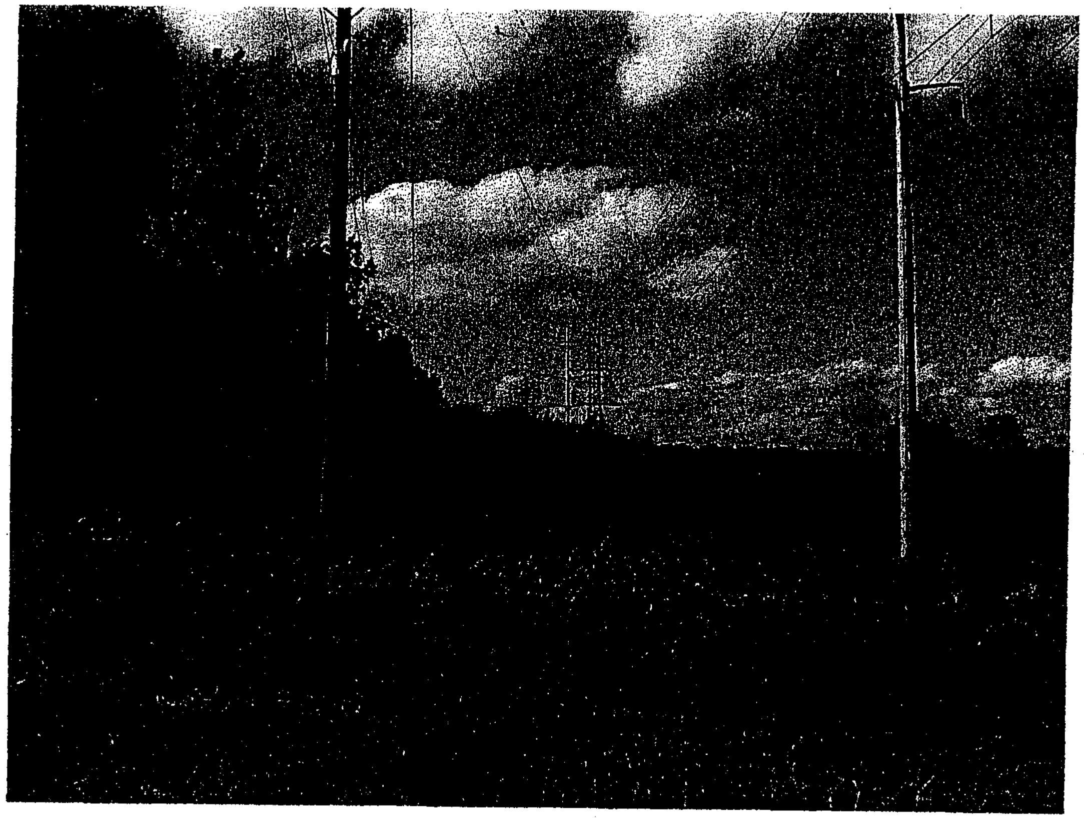
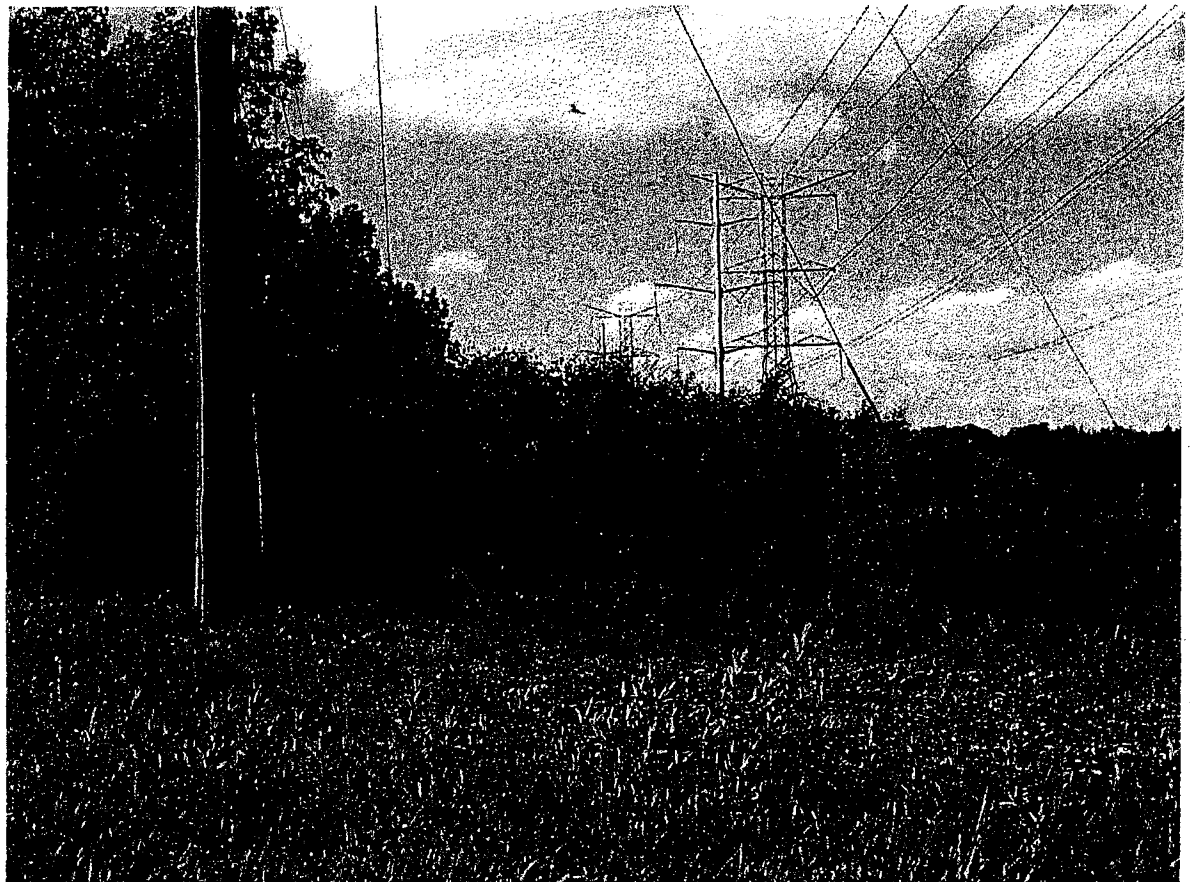
ENG 36A/12/93



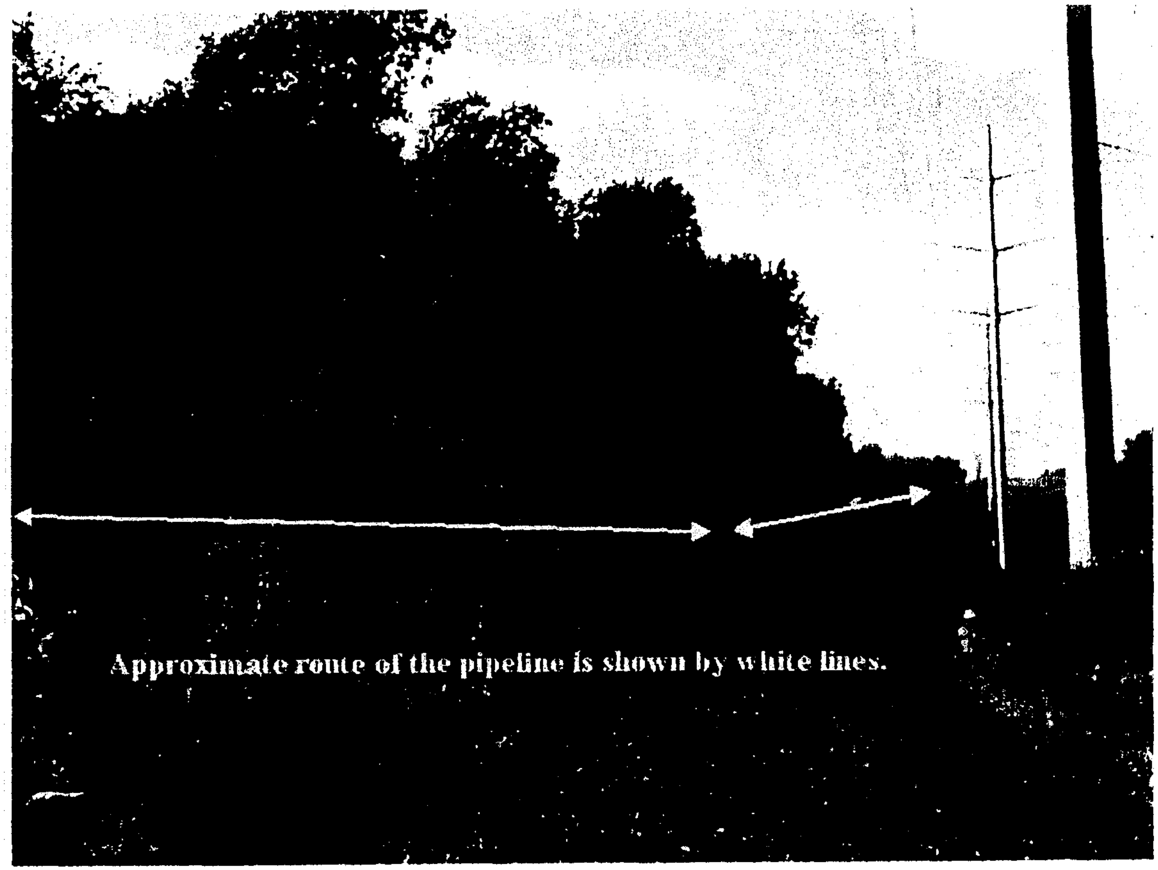
Lakehead pipeline right-of way looking north from the mainline valve setting area just outside the Dundee, IL station.

Item No. 3



Another view looking north along Lakehead pipeline right-of-way near the Dundee, IL station.

Item No. 4



Looking north-northwest at Lakehead right-of-way near Dundee, IL station.

Item No. 5

Annual Tank Inspection Report

(Include Fuel Tanks) D.O.T. Compliance
Form #77-1

Station/Terminal STOCKBRIDGE Date 6/4/2001
Tank No. 80 Cone Yes Floater Internal
Service Heavy Crude Oil Mixers Jensen 1
Type No.

1. Catwalks	Y	
2. Stairways and bents	Y	
3. Shell, External Condition	Y	Maintenance painting needed at chime
4. Shell Nozzles, Manholes and Cleanouts	Y	
5. Water Drawoffs	N/A	
6. Foundation Ringwall/Level/Condition	Y	
7. Shell (Floater) Internal Condition	N/A	Not Inspected
8. Roof condition ~~(floater-include pontoons)~~ Cone	Y	
9. Tank seal condition	N/A	Not Inspected
10. Roof vents and bleeder vents or valve	N/A	Not Inspected
11. Roof (floater) drain	N/A	Not Inspected
12. Roof ~~manholes/nozzles/legs~~ Cone Roof	Y	
13. Gauging well and platform	Y	
14. Tank gauge system (except circuits)	Y	
15. Tank lines and valves	Y	
16. Tank lots dikes, drain and bottom condition	Y	
17. Other		

Recommendations: Paint Valve Platform Handrails Yellow
Install galvanized pins on davit arm
Paint Radar level gauge nozzle
Grade around ringwall to allow drainage from tank
Control Vegetation around ring-wall

High-High tank alarm tested O.K. Control Center seen alarm.

Attach and complete tank seal Gap Inspection Record for Griffith Tanks and Superior Tank 25

New as of 1992

Inspected by M.J. Moeller
Signature
Assisted by Tim Hulock LPL
Ray Landry CCI

COPIES: Originating Location, District Office (2)

Figure 2
Annual Tank Inspection Form—USA

Item No. 6

Annual Tank Inspection Report

(Include Fuel Tanks)

D.O.T. Compliance
Form #77-1

Station/Terminal STOCKBRIDGE
Tank No. 81
Service Heavy Crude Oils

Date 6/9/2001
Cone Yes Floater Internal
Mixers Jensen 2
Type No.

1. Catwalks	Y	
2. Stairways and bents	Y	
3. Shell, External Condition	Y	Maintenance Painting In Progress
4. Shell Nozzles, Manholes and Cleanouts	Y	
5. Water Drawoffs	Y	
6. Foundation Ringwall/Level/Condition	Y	
7. Shell (Floater) Internal Condition	N/A	Not Inspected
8. Roof condition ~~(floater–include pontoons)~~ Cone	Y	
9. Tank seal condition	N/A	Not Inspected
10. Roof vents and bleeder vents or valve	N/A	Not Inspected
11. Roof (floater) drain	N/A	
12. Roof ~~manholes/nozzles-legs~~ Cone Roof	Y	
13. Gauging well and platform	Y	
14. Tank gauge system (except circuits)	N	Varec needs to be replaced
15. Tank lines and valves	Y	
16. Tank lots dikes, drain and bottom condition	Y	
17. Other		

High-High Alarm was manually tested - test O.K. Alarm seen at Control Center.

Recommend installation of galvanized pins on davit arm.

Attach and complete tank seal Gap Inspection Record for Griffith Tanks and Superior Tank 25

New as of 1992

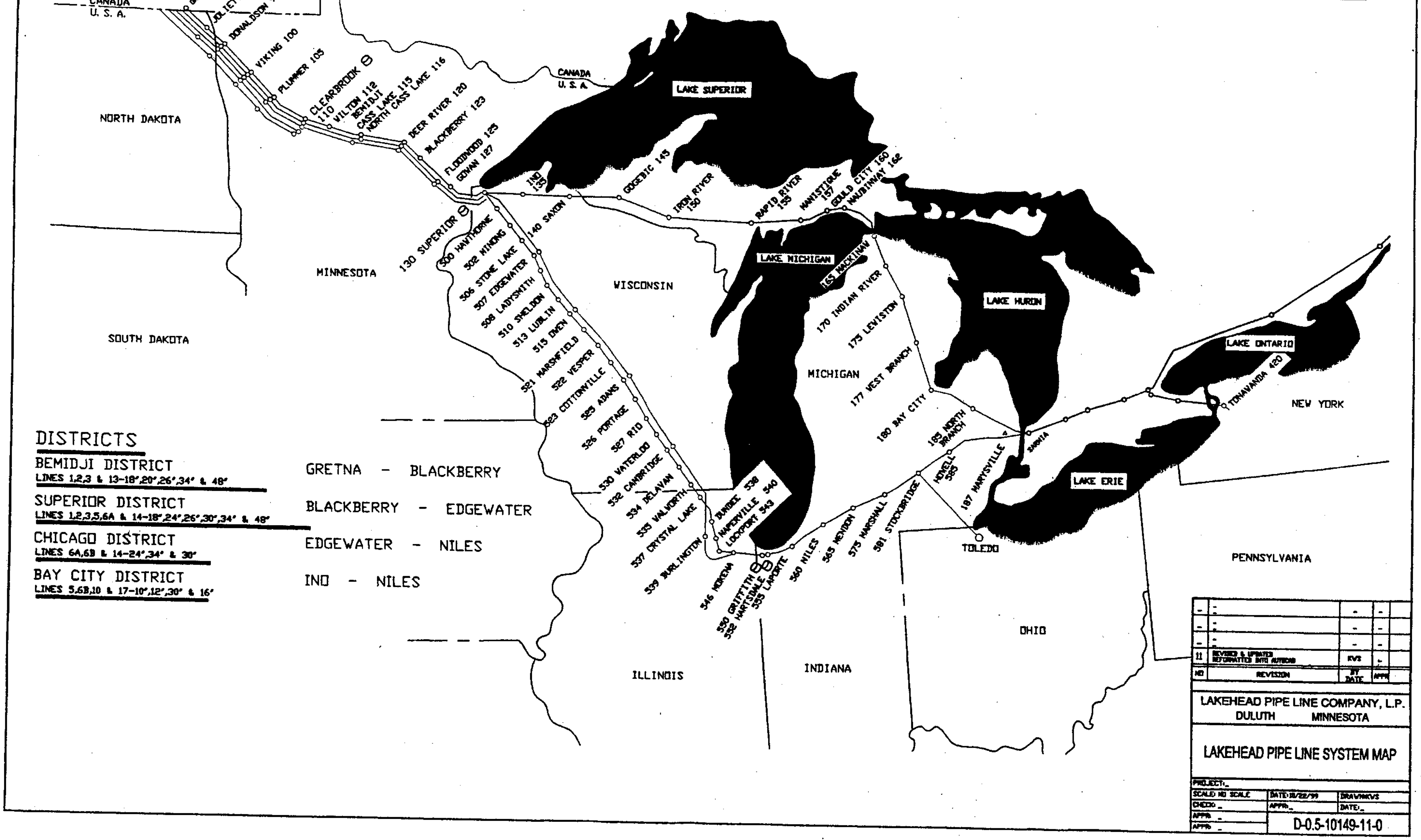
Inspected by M Moeller
Signature

COPIES: Originating Location, District Office (2)

Assisted by Tim Hurlock LPL
Ray Lundry CCI

Figure 2
Annual Tank Inspection Form—USA

LAKEHEAD PIPE LINE SYSTEM MAP



Item No. 8

OIL PIPELINES (CONTINUED)

Company	Miles of pipeline: Gathering	Trunk: Crude	Trunk: Products	Total	Deliveries, 1,000 bbl: Crude	Products	Total	Total trunkline traffic, million bbl-miles: Crude	Products	Total	Fiscal data, $1,000: Carrier property	Change	Operating revenue	Income
Endicott Pipeline Co.	—	26	—	26	13,433	—	13,433	349	—	349	60,042	47	6,746	3,291
Energy Development Corp. (HIPS) Inc.	NR	NR	—	—	92	—	92	11	—	11	NR	NR	60	NR
Enterprise Lou-Tex NGL Pipeline LP	—	—	276	276	—	1,585	1,585	—	—	—	86,497	83,694	2,029	-1,232
EOTT Energy Pipeline LP	1,286	7,422	—	8,708	94,141	—	94,141	8,593	—	8,593	306,027	3,947	64,537	46,214
Equilon Pipeline Co. LLC	1,789	5,793	2,447	10,029	925,869	389,237	1,315,106	152,292	24,401	176,693	1,078,531	42,821	451,458	245,176
Ewing Bank Pipeline Co.	—	23	—	23	461	—	461	11	—	11	7,665	—	955	836
Explorer Pipeline Co.	—	—	1,413	1,413	—	183,684	183,684	—	138,452	138,452	291,535	5,273	146,179	38,859
Express Pipeline Partnership	—	513	—	513	51,160	—	51,160	26,245	—	26,245	324,069	2,199	38,726	-4,861
ExxonMobil Pipeline Co.	1,648	3,038	1,987	6,673	391,179	224,527	615,706	78,440	12,574	92,014	544,441	27,191	395,841	226,532
Farmland Industries Inc.	307	199	—	506	31,717	—	31,717	1,046	—	1,046	13,518	874	6,520	NR
Forest Pipeline Co.	—	12	—	12	138	—	138	1	—	1	NR	NR	3	NR
Frontier Pipeline Co.	—	290	—	290	13,738	—	13,738	3,917	—	3,917	69,037	763	15,757	12,696
Genesis Pipeline USA LP (1999)	231	194	—	425	13,471	—	13,471	715	—	725	40,568	314	7,767	3,444
Gulf Pipeline Co. (new)	—	—	—	—	252	—	252	—	7	7	[illegible]	[illegible]	[illegible]	[illegible]
Heartland Pipeline Co.	—	—	49	49	—	7,464	7,464	—	1,917	1,917	13,158	334	5,624	2,963
Hess Pipeline Co.	—	86	—	86	2,601	—	2,601	274	—	274	10,694	—	5,505	3,291
IMTT Pipeline	—	—	NR	—	—	13,230	13,230	—	81	81	6,003	486	2,101	795
Jayhawk Pipeline LLC	23	819	—	842	52,371	—	52,371	8,504	—	8,504	55,253	5,593	17,516	4,431
Jolliet Pipe Line Co.	29	—	—	29	1,908	—	1,908	NR	—	—	12,012	—	1,435	654
Kaneb Pipe Line Operating Partnership LP	—	—	2,627	2,627	—	85,903	85,903	—	17,815	17,815	178,247	3,227	68,578	31,841
Kenai Pipe Line Co.	—	23	—	23	21,123	10,143	31,266	13	6	19	22,561	2,676	7,121	1,762
Kiantone Pipeline Corp.	—	78	—	78	22,812	—	22,812	1,785	—	1,785	10,792	39	4,791	2,140
Kinder Morgan Operating LP "A"	—	—	1,694	1,694	—	46,061	46,061	—	13,059	13,059	174,194	2,413	41,145	81,620
Koch Pipelines Inc.	—	1,456	3,354	4,810	28,427	130,530	158,957	23,170	50,013	73,183	547,977	7,791	125,447	81,535
Kuparuk Transportation Co.	—	NR	—	—	107,069	—	107,069	2,802	—	2,802	133,211	1,198	22,218	11,718
Lakehead Pipe Line Co. LP	—	3,200	—	3,200	488,195	—	488,195	342,523	—	342,523	1,678,446	19,443	305,857	80,968
Largo Co., The	12	—	—	12	—	—	—	—	—	—	426	—	—	6,901
Locap Inc.	—	59	—	59	355,907	—	355,907	22,769	—	22,769	131,351	3,672	21,885	7,125
Marathon Ashland Pipe Line LLC	68	2,633	1,505	4,206	525,137	292,901	818,038	148,918	21,039	169,957	397,925	19,086	229,043	102,830
Marathon Pipe Line LLC	174	306	—	480	21,485	—	21,485	682	—	682	46,872	518	12,048	7,934
Mars Pipeline Co.	—	121	—	121	131,131	—	131,131	11,037	—	11,037	149,392	11,190	98,928	60,030
Mid-America Pipeline Co.	2,013	39	5,221	7,273	56,872	224,763	281,635	1,081	111,007	112,088	912,429	46,999	201,283	53,349
Mid-Valley Pipe Line Co.	—	1,087	—	1,087	116,714	—	116,714	65,163	—	65,163	81,100	1,426	46,466	10,319
Milne Point Pipe Line Co.	—	11	—	11	19,075	—	19,075	210	—	210	34,810	322	8,965	2,607
Minnesota Pipe Line Co.	—	675	—	675	103,337	—	103,337	26,454	—	26,454	126,183	623	38,873	9,822
Mobil Alaska Pipeline Co.	—	—	—	—	3,862	—	3,862	—	3,254	3,254	—	—	12,792	-28,195
Mobil Eugene Island Pipeline Co.	—	63	—	63	6,765	—	6,765	478	—	478	18,116	1,274	7,064	5,223
Mobil Pacific Pipeline Co.	117	10	3	129	9,448	2,951	12,399	66	24	90	24,447	182	1,825	79
Mobil Pipeline Co.	1,565	3,141	1,273	5,979	252,413	141,887	394,300	53,149	12,721	65,870	329,739	1,738	172,042	180,780
MOEM Pipeline LLC	—	56	—	56	24,919	—	24,919	1,379	—	1,379	13,450	—	1,218	NR
Mustang Pipe Line Partners	—	211	—	211	9,890	—	9,890	199	—	199	56,387	65	2,054	-2,763
Navajo Pipeline Co.	135	20	277	432	18,258	12,133	30,391	NR	NR	—	39,339	543	213,334	4,492
NW Pipeline Inc.	NR	NR	NR	—	503	—	503	63	—	63	6,367	232	403	134
Ohio Oil Gathering Corp. II	137	—	—	137	2,845	—	2,345	NR	—	—	10,676	98	4,024	-713
Ohio River Pipe Line LLC	—	—	400	400	—	39,821	39,821	—	4,843	1,843	87,887	10,439	10,439	3,475
Olympic Pipe Line Co.	—	—	399	399	—	63,559	63,559	—	8,143	8,143	144,265	11,686	23,040	-18,806
Osage Pipe Line Co.	—	135	—	135	39,355	—	39,355	5,314	—	5,318	19,942	492	9,318	2,790
Pacific Pipeline System LLC (new)	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Pakoma Pipe Line Co.	—	46	—	46	5,433	—	5,433	228	—	228	13,623	16	1,547	2,270
Phillips Alaska Pipeline Corp.	—	818	—	818	5,342	—	5,342	3,908	—	3,908	140,817	607	13,460	1,118
Phillips Pipe Line Co.	180	160	2,613	2,953	21	94,728	94,749	195	24,845	25,040	407,291	9,172	84,237	59,387
Phillips Texas Pipeline Co.	634	612	1,043	2,289	59,349	156,460	215,809	11,985	8,133	20,118	158,405	8,066	99,967	52,093
Phillips Transportation Alaska Inc. (new)	—	—	—	—	—	—	—	—	—	—	—	—	—	1,118
Pioneer Pipe Line Co.	—	—	299	299	—	23,255	23,255	—	4,436	4,436	82,302	63,570	9,614	1,500
Plains Seudock Permian LP	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Plantation Pipe Line Co.	—	—	3,134	3,134	—	228,796	228,796	—	134,675	134,675	437,510	43,112	157,726	87,898
Platte Pipe Line Co.	—	996	—	996	52,694	—	57,694	34,560	—	34,560	215,610	3,617	29,403	-1,353
Pogo Offshore Pipeline Co.	—	NR	—	—	155	—	155	5	—	5	1,346	—	276	51
Point Arguello Pipeline Co. (1999)	—	28	—	28	7,304	—	7,304	205	—	205	274,768	280	41,857	24,661
Point Arguello Terminal Co. (1999)	—	NR	—	—	7,414	—	7,414	4	—	4	274,486	NR	3,157	723
Point Pedernales Pipeline	—	46	—	46	2,393	—	2,393	65	—	65	46,571	686	44,147	17,619
Portland Pipe Line Corp.	10	334	—	344	156,937	—	156,937	52,417	—	52,417	70,428	8,802	59,240	12,376
Premcor Pipeline Co. (formerly Clark Pipe Line Co.)	—	56	—	56	19,629	—	19,629	1,080	—	1,080	31,864	3	1,598	439
Propylene Pipeline Partnership LP	—	—	126	126	—	1,866	1,866	—	64	64	21,549	29	269	-579
Razorback Pipeline Co.	—	—	67	67	—	4,661	4,661	—	311	311	12,385	—	2,191	1,502
Red Butte Pipe Line Co. (new)	177	755	—	932	20,581	—	20,581	1,251	—	1,251	17,669	3,271	6,502	326

Item No. 9

Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

September 26, 2002

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5015

In our June 27, 2002 letter to you, we responded to items 1 and 2 from your "Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order", dated June 5, 2002. Following is the status of item 3:

3. *195/401(b) During field inspection it was observed that the view of LPL's right-of-way was obstructed at 12 separate locations.*

   Mowing, brushing and clearing work on 11 of the 12 identified areas has been completed. The location not yet completed is M.P. 1460.187, which is in Mackinaw County, Michigan. The view of the right of way at this location is obstructed by 400-600 red pine trees in the Hiawatha National Forest. Enbridge personnel have been coordinating efforts with the local forester in the St. Ignace Office. All appropriate permitting forms were submitted the first week of July, and we are awaiting approval from the St. Ignace Office so that we can proceed with clearing activities.

   We expect to commence clearing this area early in October, and will advise when the work has been completed.

If you would like more detailed information for any of the twelve locations, please contact me.

Sincerely,

John R. Sobojinski

Attachment – June 5, 2002 Letter

c: John W. Hayes
Greg L. Sevick
Dan C. Tutcher

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
AND
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 5, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5015

Dear Mr. Tutcher:

During May 7 - May 18, June 11 - 22 and August 27, 2001, representatives of the Central Region Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted onsite pipeline safety inspections of your Lakehead pipeline (LPL) facilities and records at Duluth, MN (records); Bay City, MI (records); Griffith, IN (records); Fort Atkinson, WI (PLM records); Ironwood, MI (PLM records); Escanaba, MI (records); Superior, WI (records); States of Michigan, Indiana, Illinois and Wisconsin (field facilities).

As a result of the inspections, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1. **§ 195.310 Records.**
   § 195.310(b) The record required by paragraph (a) of this section must include:

   § 195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The pressure test records for Line #17 (Stockbridge, MI to Freedom Junction, MI) did not contain a profile of the line although there are elevation differences that exceed 100 feet along the route for Line #17 (Crude System #3).

2. **§ 195.432 Inspection of in-service breakout tanks.**

§ 195.432(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.

During the records review at Bay City, MI it was observed that LPL did not have documentation for annual tank inspections for the Stockbridge, MI station for the year 2000 (Crude System #3).

3. **§ 195.401 (b) General requirements.**

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

During the field inspection it was observed that the view of LPL's right-of-way was obstructed at the following locations:

a. MP1164.60 - west side (Crude System #2)
b. MP1238.153 (Crude System #2)
~~c. MP1247.89 (Crude System #2)~~
d. MP1260.166 - west side (Crude System #2)
e. MP1280.307 - west side (Crude System #2)
f. MP1387.577 - east side (Crude System #2)
g. MP1429.301 - west side (Crude System #2)
h. MP1439.71 - Black River crossing (both sides) (Crude System #2)
i. MP1460.187 (Crude System #2)
j. MP1465.50 - east side (Crude System #2)
k. MP 515.100 (Line 6B) - east side of the road (Crude System #3)
l. MP 383.090 (Line 6A) Dundee Station - due north and south from the mainline valve located outside the station fencing (Crude System #3)

Right-of-way inspections conducted by the operator under § 195.412(a) should have noted that an aerial view of the right-of-way was obstructed by overgrowth.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $25,000 for each violation for each day the violations persist up to a maximum of $500,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and it is her recommendation that you be preliminarily assessed a civil penalty as follows:

Item 1 - $ 5,000
Item 2 - $ 5,000
$10,000.

Additionally, pursuant to 49 United States Code § 60118, the Office of Pipeline Safety proposes to issue to you a compliance order with respect to Item 3. That proposed compliance order is attached to and made a part of this Notice of Probable Violation.

Also, attached to and made a part of this Notice is a description of the available procedures for responding to this Notice. Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights under 49 CFR 190.209. No response or a response which does not contest the allegations in the Notice authorizes the Associate Administrator for Pipeline Safety to find the facts to be as alleged herein and to issue appropriate orders. The 30 day period for response may be extended for good cause shown, and submitted within the original 30 day period.

Please refer to CPF No. 3-2002-5015 in any correspondence or communication on this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enclosures

cc: Mr. John Sobojinski (w/Enclosure)
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

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ENBRIDGE™

November 6, 2002

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5015

In response to your "Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order", dated June 5, 2002, we are pleased to report completion of the final outstanding item noted in your letter:

3. *195/401(b) During field inspection it was observed that the view of LPL's right-of-way was obstructed at 12 separate locations.*

MP 1460.187, located within the Hiawatha National Forest, has been effectively cleared. A 35'-40' wide section of red pine trees, extending 300' on the west side of the road and 500' on the right, was cut and chipped by contract forces. This will ensure a clear line of vision for ongoing effective aerial patrols.

If you would like more detailed information for this particular location, please contact me. We trust that the "Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order" will now be considered closed.

Sincerely,

John R. Sobojinski

c: John W. Hayes
Greg L. Sevick
Dan C. Tutcher

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

400 Seventh St., S.W
Washington, D.C 20590

MAY 17 2004

Mr. Daniel C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: CPF No. 3-2002-5015

Dear Mr. Tutcher:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It makes findings of violation, assesses a civil penalty of $5,000, and specifies actions to be taken to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty is paid and the terms of the compliance order completed, as determined by the Director, Central Region, this enforcement action will be closed. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: Mr. John Sobojinski, Manager, U.S. Compliance and Risk Management

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
Enbridge Energy Company, Inc.,	)	CPF No. 3-2002-5015
	)	
Respondent.	)	
	)	

FINAL ORDER

On May 7 - 18, June 11 - 22, and August 27, 2001, pursuant to 49 U.S.C. § 60117, a representative of the Office of Pipeline Safety (OPS), conducted an on-site pipeline safety inspection of Respondent's facilities and records throughout the states of Michigan, Indiana, Illinois, Minnesota, and Wisconsin. As a result of the inspection, the Director, Central Region, OPS, issued to Respondent, by letter dated June 5, 2002, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had violated 49 C.F.R. §§ 195.310(b)(9), 195.432(a), and 195.401(b) and proposed assessing a civil penalty of $10,000 for the alleged violations. The Notice also proposed that Respondent take certain measures to correct an alleged violation.

Respondent responded to the Notice by letter dated June 27, 2002 (Response). Respondent did not contest the allegations of violation but provided information concerning the corrective actions it has taken and requested that the proposed civil penalty be reduced or eliminated. Respondent provided further information on corrective actions it has taken by letter dated September 26, 2002. Respondent did not request a hearing, and therefore has waived its right to one.

FINDINGS OF VIOLATION

In its Response, Respondent did not contest the alleged violations in the Notice. Accordingly, I find that Respondent violated the following sections of 49 C.F.R. Part 195, as more fully described in the Notice:

> 49 C.F.R. § 195.310(b)(9) -- failing to maintain pressure testing records for Line #17 that show the elevation and test sites over the length of Line #17 (due to elevation differences exceeding 100 feet along the length of Line #17);
>
> 49 C.F.R. § 195.432(a) -- failing to inspect in-service breakout tanks at intervals not exceeding 15 months, but at least once each calendar year; and

49 C.F.R. § 195.401(b) -- failing to address, within a reasonable time, the adverse condition that was the obstruction of numerous portions of the right-of-way from aerial view.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $100,000 per violation for each day of the violation up to a maximum of $1,000,000 for any related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require.

The Notice proposed a total civil penalty of $10,000 for violation of 49 C.F.R. §§ 195.310(b)(9) and 195.432(a).

I have determined that Respondent has no financial circumstances that would prevent it from paying on the assessed amounts and that Respondent's ability to continue in business will not be significantly affected.

OPS inspectors stated that Respondent demonstrated good faith in responding to the violations alleged in the Notice, and that Respondent quickly initiated action to correct items identified in the Notice and in this Final Order. OPS staff have taken Respondent's good faith into account when proposing civil penalties in the Notice, as well as in post-Response recommendations.

Item 1 in the Notice proposed a $5,000 penalty for violation of § 195.310(b)(9). Elevation difference is a critical factor in determining if target test pressures are being maintained at all points along the pipeline. This is necessary to assess internal stress levels on the pipe so that pipeline integrity can be assured. Failure to account for elevation differences, and thus stress, may increase the risk for a rupture or release. However, immediately after the inspection, Respondent took action to address the violation by beginning preparation of profile drawings. In light of Respondent's action to comply with § 195.310(b)(9) before receiving the official Notice, I issue a reduced civil penalty of $2,500.

Item 2 in the Notice proposed a $5000 penalty for violation of § 195.432(a). Ensuring the integrity of breakout tanks is critical to reducing the risk of release of hazardous liquids from the tanks. However, tanks 80 and 81 at the Stockbridge, Michigan station had undergone integrity inspections prior to being put into service in 1999. Further, Respondent began inspecting breakout tanks within three weeks after the inspection, before the Notice was sent. In light of Respondent's earlier inspection activities and its action to comply with § 195.432(a) before receiving the official Notice, I issue a reduced civil penalty of $2,500.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of $5,000.

Payment of the civil penalty must be made within 20 days of service. Payment may be made by sending a certified check or money order (containing the CPF Number for this case) payable to "U.S. Department of Transportation" to the Federal Aviation Administration, Mike Monroney Aeronautical Center, Financial Operations Division (AMZ-120), P.O. Box 25082, Oklahoma City, OK 73125.

Federal regulations (49 C.F.R. § 89.21(b)(3)) also permit this payment to be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-120), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-4719.

Failure to pay the $5,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Item 3 in the Notice for violation of 49 C.F.R. § 195.401(b). Pilots must have unobstructed views of areas directly above and adjacent to the pipeline during aerial patrolling of the right-of-way. Obstruction of the pilot's view could lead to missed identification of a release or of activities on or near the right-of-way that could affect the integrity of the pipeline.

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under Chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations. Respondent must:

1. Develop a plan and corresponding schedule for the clearing of obstructions hindering the view of the pipeline right-of-way. Submit the plan and schedule to the Director, Central Region for approval within 90 days of receipt of this Final Order.

2. After commencing clearing of obstructions hindering the view of the pipeline right-of-way, submit quarterly progress reports to the Director, Central Region until such time as the entire pipeline right-of-way is visible from aerial patrol. When clearing is complete, submit all schedules of dates clearing activities occurred along with a notice of completed action to the Director, Central Region.

The Director, Central Region has indicated, and this Order recognizes, that Respondent may have taken action to address some or all of the required actions. Information already submitted as evidence of compliance with the proposed required actions in the Notice will be considered by the Director, Central Region in determining compliance with this Order.

The Director, Central Region may extend the period for complying with any of the required items if the Respondent requests an extension and adequately justifies the reasons for the extension.

Failure to comply with this Final Order may result in the assessment of civil penalties of up to $100,000 per violation per day, or in the referral of the case for judicial enforcement.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issues. The filing of the petition automatically stays the payment of any civil penalty assessed. All other terms of the order, including any required corrective action, remain in full effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective on receipt.

James K O'Steen

Stacey Gerard
for Associate Administrator
for Pipeline Safety

MAY 17 2004

Date Issued

Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
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john.sobojinski@enbridge-us.com

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June 27, 2002

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

<u>CPF No. 3-2002-5015</u>

Your "Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order", dated June 5, 2002 (attached), identified three items of concern, each of which is addressed below:

1. *195.310(b)(9) The pressure test records for Line #17 (Stockbridge, MI to Freedom Junction, MI) did not contain a profile of the line although there are elevation differences that exceed 100 feet along the route for Line #17.*

This item was identified during the June 11 – 22, 2001 audit and immediate steps were taken to correct this 1999 construction record oversight. Profile drawings have since been prepared and are now a part of the hydrotest records. Maximum allowable operating pressure (MAOP) calculations for Line 17 have been confirmed in conjunction with the elevation profile and no changes are required as a result of this evaluation. Although not in place at the time of the audit, Enbridge did immediately rectify this situation and at no time was the health and safety of the public at risk.

2. *195.432(a) During the records review at Bay City, MI it was observed that LPL did not have documentation for annual tank inspections for the Stockbridge, MI station for the year 2000.*

Tank 80 was purchased in 1998 at which time a complete API 653 inspection was performed. It was not put into Enbridge service until 1999. Tank 81 was constructed in 1998 and also put into Enbridge service in 1999. While the first annual inspections for both tanks were not completed within the required 15-month time frame, both tanks had recently undergone much more rigorous integrity inspections prior to being put into service. Both tanks 80 and 81 underwent annual inspections within 3 weeks after identifying this audit item. Company procedures have been reviewed and a process was put into place to help ensure such instances are not repeated.

3. *195/401(b) During field inspection it was observed that the view of LPL's right-of-way was obstructed at 12 separate locations.*

   A Proposed Compliance Order was issued to Enbridge for item 3. Each location that has been identified is currently under review to ascertain its status. We are identifying those locations that have already been cleared and for those that remain, and will prepare a detailed action plan for submission within 90 days of receipt of your Final Order as required by the Compliance Order.

Enbridge is a proactive company and we strive to operate our pipeline in a manner which gives highest consideration to public safety and the environment. It is hoped that our actions to address the issues identified above provides sufficient justification for elimination of the proposed civil penalty. If you require further information or supporting documents for any of the above information, please contact me.

Sincerely,

John R Sobojinski
jb

John R. Sobojinski

Attachment – June 5, 2002 Letter

c: John W. Hayes
Greg L. Sevick
Dan C. Tutcher

U.S. Department of Transportation

Research and Special Programs Administration

OFFICE OF PIPELINE SAFETY
CENTRAL REGION OFFICE

DATE: 3/3/03 TIME:

NUMBER OF PAGES (including this page): 3

TO: James Reynolds

PHONE: (202)-366-2786 FAX: (202) 366-4566

FROM: PHONE: (816) 329-3807

- ☑ Phil Archuletta
- ☐ Dave Barrett
- ☐ Allan Beshore
- ☐ Sandy Cline
- ☐ Linda Daugherty
- ☐ Benson Dushane
- ☐ Ivan Huntoon
- ☐ Joshua Johnson
- ☐ Judy Johnson
- ☐ Bill Lowry
- ☐ Warren Miller
- ☐ Tom McMaster
- ☐ Don Moore
- ☐ Stewart Rickey
- ☐ Hans Shieh
- ☐ Leonard Steiner

Main Phone: (816) 329-3800 Fax: (816) 329-3831
901 Locust St., Room 462
Kansas City, MO 64106

COMMENTS: PER YOUR REQUEST

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 15, 2010

Mr. Terry McGill
President
Enbridge Energy, LP
Suite 3300
1100 Louisiana
Houston, TX 77002

CPF 3-2002-5015

Dear Mr. McGill:

On May 17, 2004, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued to Enbridge Energy, LP, a Final Order in the above-referenced case. This Order included a Compliance Order and Civil Penalty assessment. Based on our review of the documentation you provided and confirmation of payment of the civil penalty, it has been determined that you have complied with the terms of this Order.

Accordingly, this case is now closed and no further action is contemplated with respect to the matters involved in this case. Thank you for your cooperation in this matter.

Sincerely,

David Barrett
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Response to DOT Letter dated June 5, 2002
Reference: CPF No. 3-2002-5015
Action Plan for Item 3 - Mitigation of Obstructed View of Enbridge Right-of-Way

Location	Scope of Project	Action By	Scheduled Start Date	Actual Completion Date
a. MP1164.60 west side	Approval to access property to start mowing operations was gained on 8/12/02. Mowing started 08/20/02 and finished on 08/22/02.The contractor hired was Asplundh Brush Control Co. The machine used was called a Nodwell which is a rubber tracked machine designed to access wet areas with little or no damage to the environment that may be caused from rutting. The mowing started at Government Road (stationing 3514+66) and went West 10,000 ft. to the White River (Sta.3414+66), also went East 600 ft. from Government Road to the Bad River (sta. 3520+66) for a total of 10600 ft. The area consisted of mostly cattails, tag alder brush and swamp grass.	Mike Paradise	08/20/02	08/22/02
b. MP1238.153	Started mowing 08/19/02 at Wolf Lake Road (sta.7394+50) and went West to the Middle Branch of the Ontonogan River (sta. 7365+81) for a total of 2869 ft. The contractor hired was Asplundh Brush Control Co. The machine used was called a Nodwell, which is a rubber tracked machine designed to access wet areas with little or no damage to the environment which otherwise may cause rutting. A 25 ft. Greenbelt, which will not affect Ariel coverage, was to remain on both sides of Wolf Lake Road per landowners request as this is a private resort complex. The area consisted of small spruce and pine trees along with swamp grass and tag alder brush. Mowing was finished 08/20/02.	Mike Paradise	08/19/02	08/20/02
c. MP1247.89	Approval to access property from the Ottawa National Forest to start mowing operations was gained on 08/19/02. Mowing started 08/26/02 at Marion Lake Road (sta.7909+89 and continued to the West 4000 ft (sta.7869+89) where brush thinned out, also from Marion Lake Road mowed East 2000 ft. (sta. 7929+89) to small tributary where brush thinned out. The area consisted of swamp brush, cattails, and Tag alder brush. The contractor hired to do the mowing was Asplundh Brush Control Co. Mowing finished 08/28/02. The machine used to do the mowing is called a Nodwell, which is rubber tracked to minimize any rutting that could occur in wet areas.	Mike Paradise	08/26/02	08/28/02
d. MP1260.166 west side	Started mowing 08/12/02 at Cooks Run Creek (sta. 8556+04) and went West 1220 ft. (sta.8543+84) to high ground which had been mowed at a prior time. The area consisted of swamp brush, cattails and tag alder	Mike Paradise	08/12/02	08/13/02

	brush. The contractor hired to do the mowing was Asplundh Brush Control Co. and the machine used to do the mowing was called a Nodwell, which is a rubber-tracked machine designed to minimize rutting in wet areas. This project was finished 08/13/02.			
e. MP1280.307 west side	Started mowing 08/12/02 at East Lake Emily Road (sta.9609+38) and mowed East 300 ft. (sta.9612+38) to high ground, then from road West 200 ft. (sta.9609+38) for a total of 500 ft. mowed. These areas were actually ditch lines of Lake Emily Road that in the past had been wet and deep. The contractor was Asplundh Brush Control Co. and the machine used to do the mowing is called a Nodwell, which is a rubber-tracked machine designed to do minimal damage to wet areas that would otherwise be rutted. This project was completed 08/12/02.	Mike Paradise	08/12/02	08/12/02
f. MP1387.577 east side	Started brushing 08/07/02 at stationing (15283+91) and went East or downstream to two track road (sta.15297+60) or approximately 1369 ft. This area is wet and consisted of tag alder brush and cattails with some small spruce trees. The contractor was Asplundh Brush Control Co. The machine that was used is called a Nodwell which is a rubber tracked wide pad machine designed to minimize any rutting that could occur in soft wet areas such as this. Project was completed on 08/08/02.	Mike paradise	08/07/02	08/08/02
g. MP1429.301 west side	Started brushing 08/06/02 at edge of Hwy. M-117 (sta.17487+10) and mowed upstream to the west 3730 ft to where heavy brush thinned out (sta.17449+80). The area that was mowed consisted of tag alder brush and cattails. The contractor doing the mowing was Asplundh Brush Control Co.; the machine used was called a Nodwell, which is a large rubber tracked machine designed to not rut in wet areas. This project was finished 08/07/02.	Mike Paradise	08/06/02	08/07/02
h. MP1439.71 Black River crossing (both sides)	Started brushing 08/05/02 at (sta.18008+00) and mowed East downstream to (sta.18025+00) for a total area of 1700 ft. less 50 ft. area of greenbelt. This area is a ravine that has a 90-ft. elevation drop on the West side of the river and a 60 ft.drop on the East side of the river. The stationing of the Black River is (18018+33). This area had a large amount of spruce trees along with tag alder brush, which made it appear thick from the air. A greenbelt of 25 ft. was to remain per Michigan Dept. of Natural Resources request on each side of the river to support riverbanks and subdue any erosion problems that could arise, along with keeping ORV vehicles from driving through the river This project was finished on 08/06/02 with the contractor being Asplundh Brush Control Co. The machine used was called a Nodwell, which is rubber tracked to minimize any rutting that could occur in wet areas.	Mike Paradise	08/05/02	08/06/02

i. MP1460.187	This area consist of approximately 400 to 600 Red Pine trees combined on both sides of U.S. Forest Road 3108 (sta.19118+21). This is U.S. Forest property and the permitting process was started on 07/09/02 and to this point is still ongoing. As of 09/18/02 still waiting on permitting from Hiawatha National Forest.	Mike Paradise	07/09/02	~~Permitting?~~ 11-4-02
j. MP1465.50 east side	The ESCANABA PLM crew completed this area in October of 2001. A considerable amount of Red Pine trees and brush were removed by the landowner and the PLM crew chipped and mulched the remaining tops and brush. Also a fence was installed per landowners request to keep vehicle and ORV traffic from accessing R/W.	Mike Paradise	7-01	7-01
k. MP515.100 (Line 6B) east side of the road		Ted Halverson		SEE LETTER
l. MP383.090 (Line 6A) Dundee Stn (due north and south from the ML valve located outside station fencing)		Ted Halverson		PHOTOS DOCUMENTING COMPLETION FROM TED ON 7-2-02

6/25/02

Ted H Halverson

07/02/2002 01:18 PM

To: Patsy M Bolk/LPL@LPL
cc:
Subject: Re: DOT Response Details

Before:

- Dundee Station - excessive brush in the ROW both upstream (North) and downstream (South). AI N 195.412(a) The area of Dundee Station for both 1 mile North and 1 mile South has been brushed.

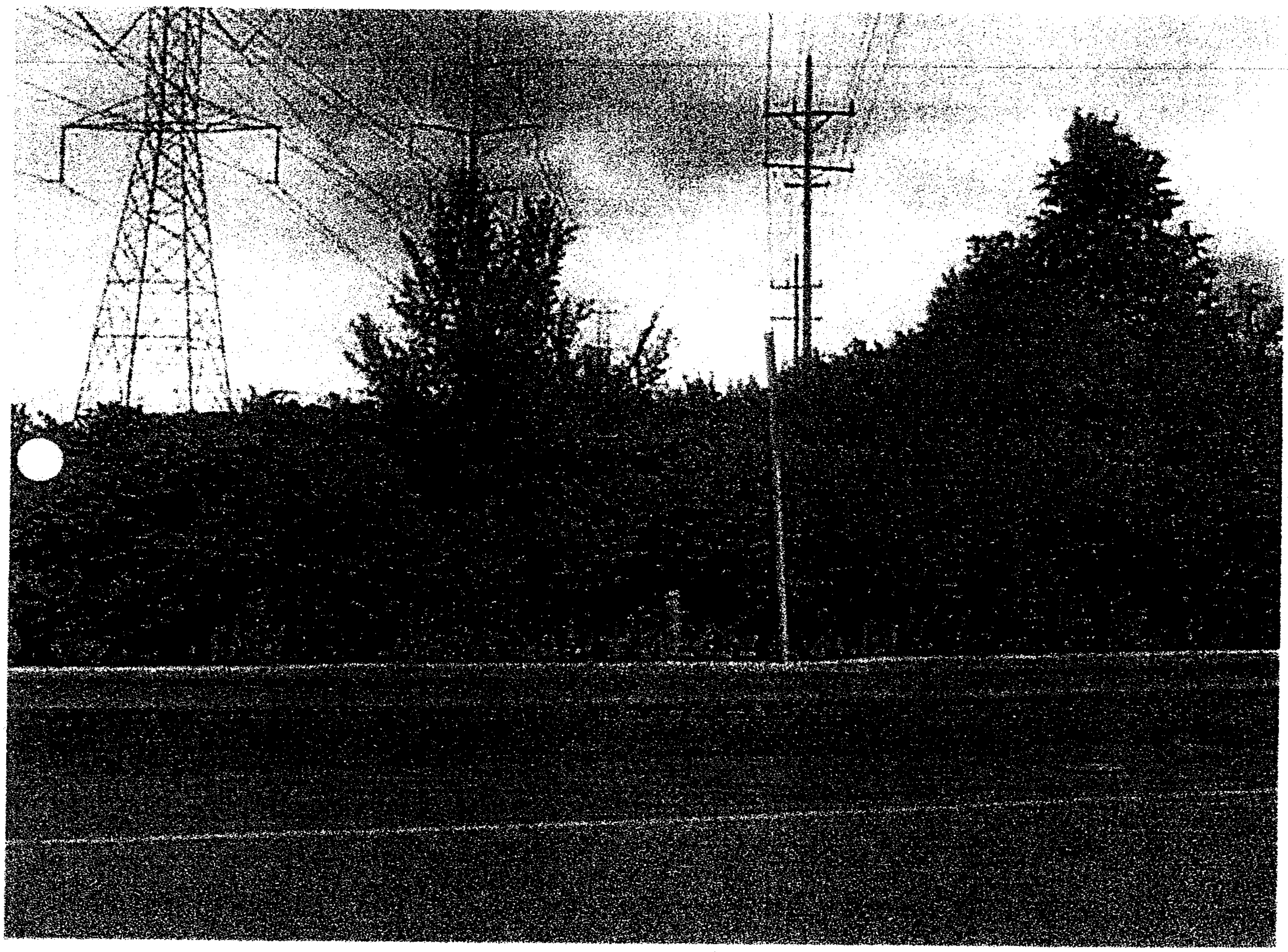
Dundee S Brush.jpg Dundee N Brush.jpg Dundee N Brush II.jp

After:

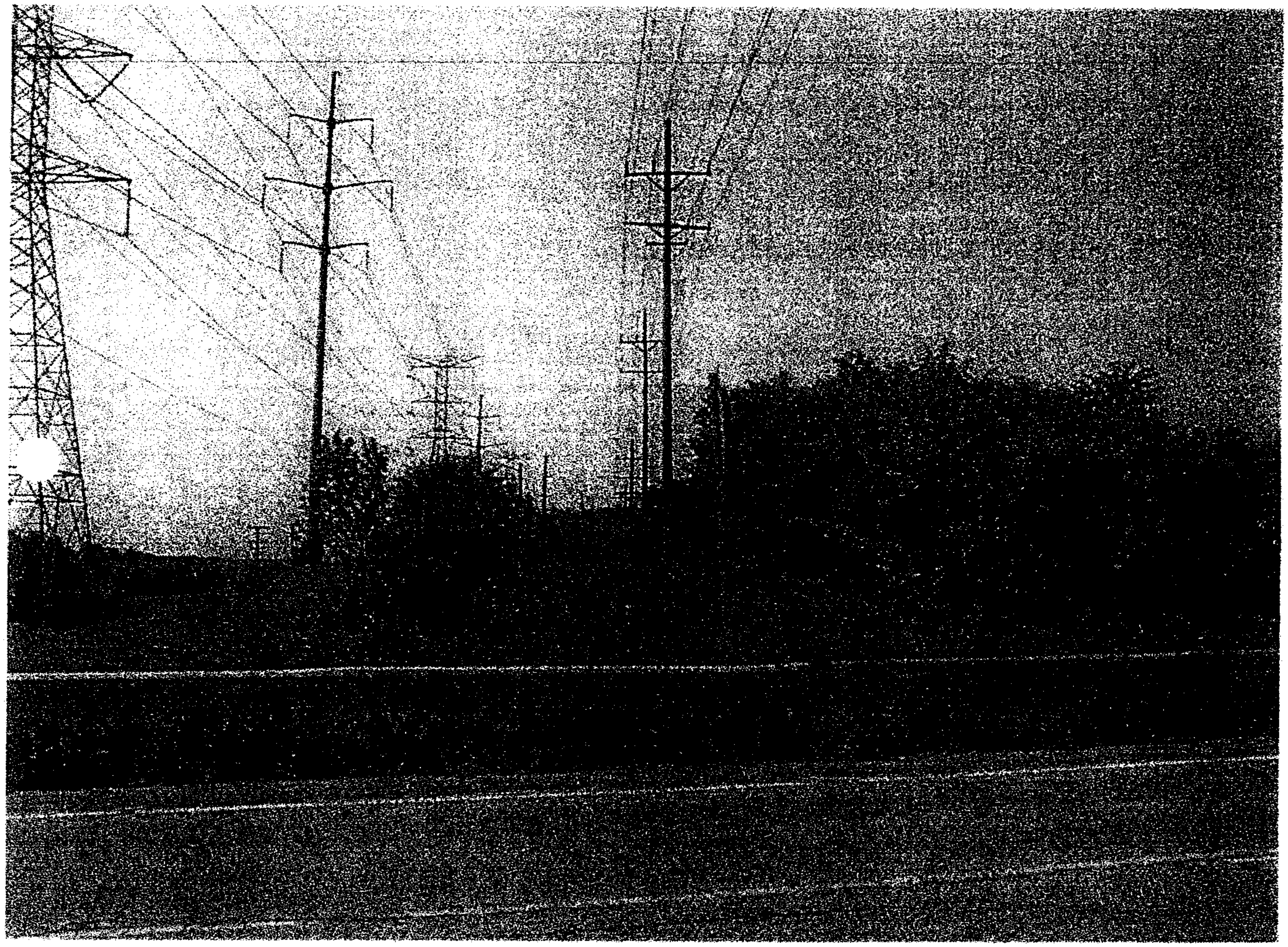
Here are the pictures of Rt 68 and Penny Rd (the next road south of the station).

Rt 68 looking south.JPG Rt 68 looking north.JPG

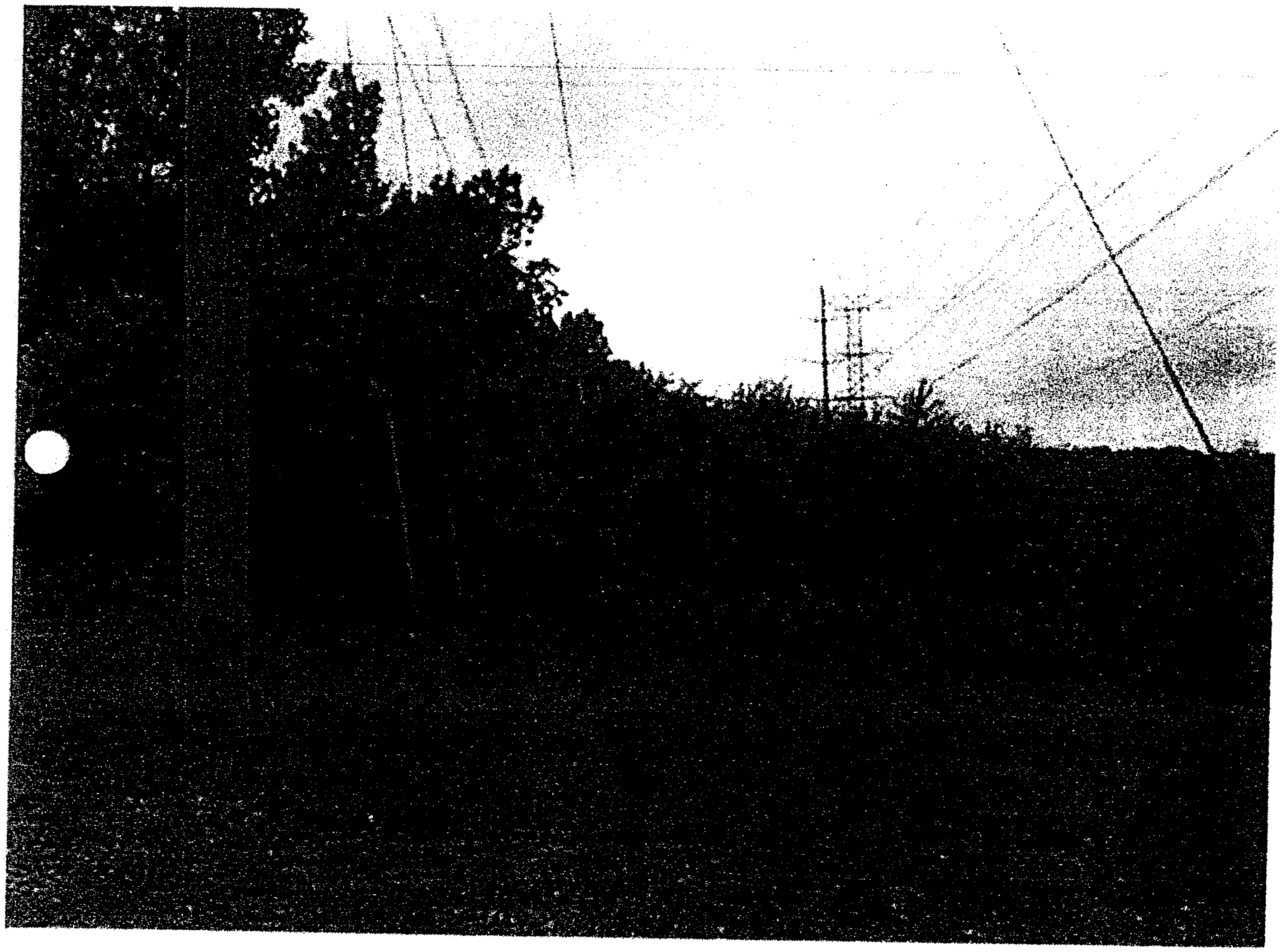
Looking north from Rt 68 You will see some evergreen trees. they are around a valve site.



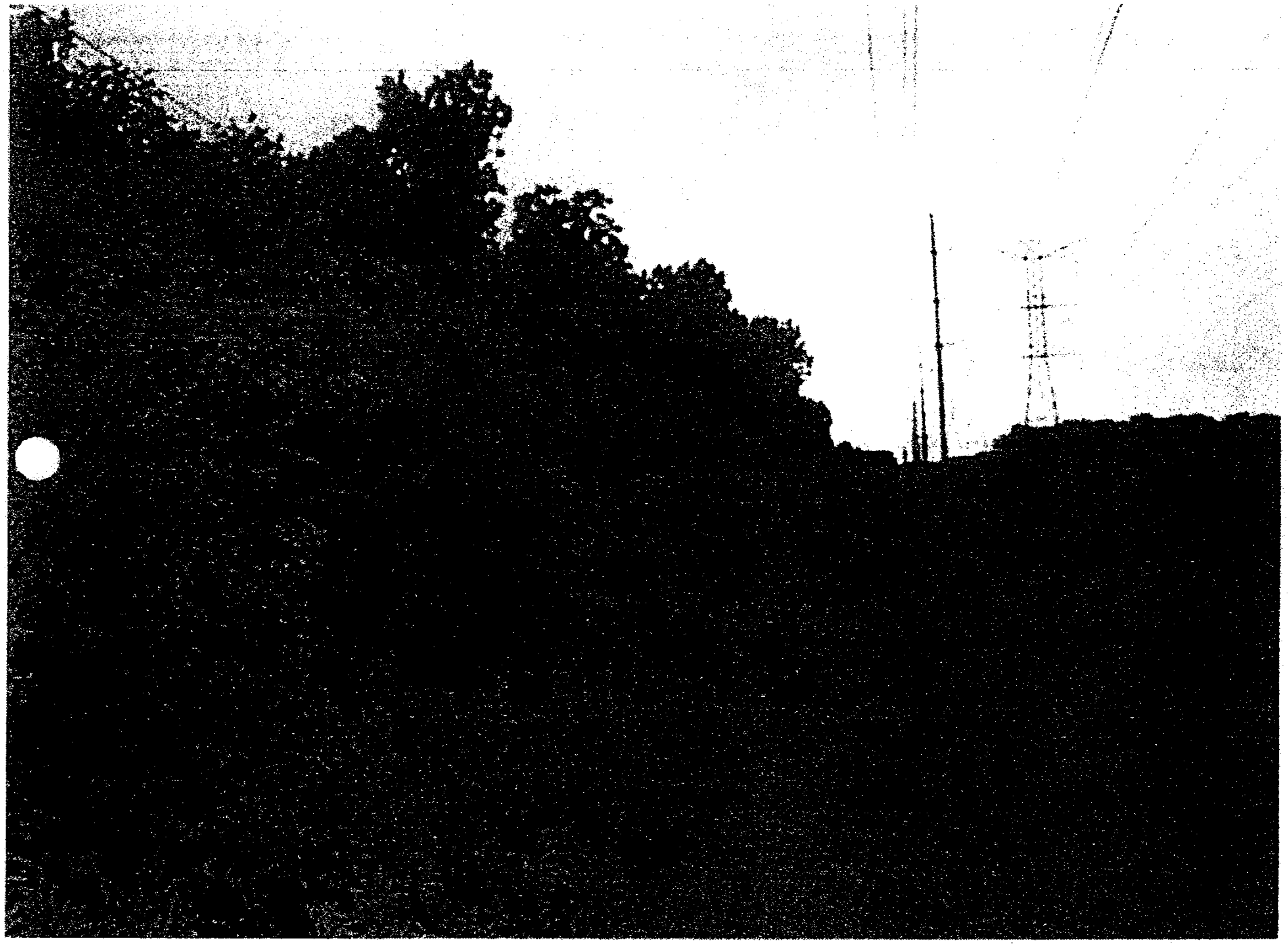
Before



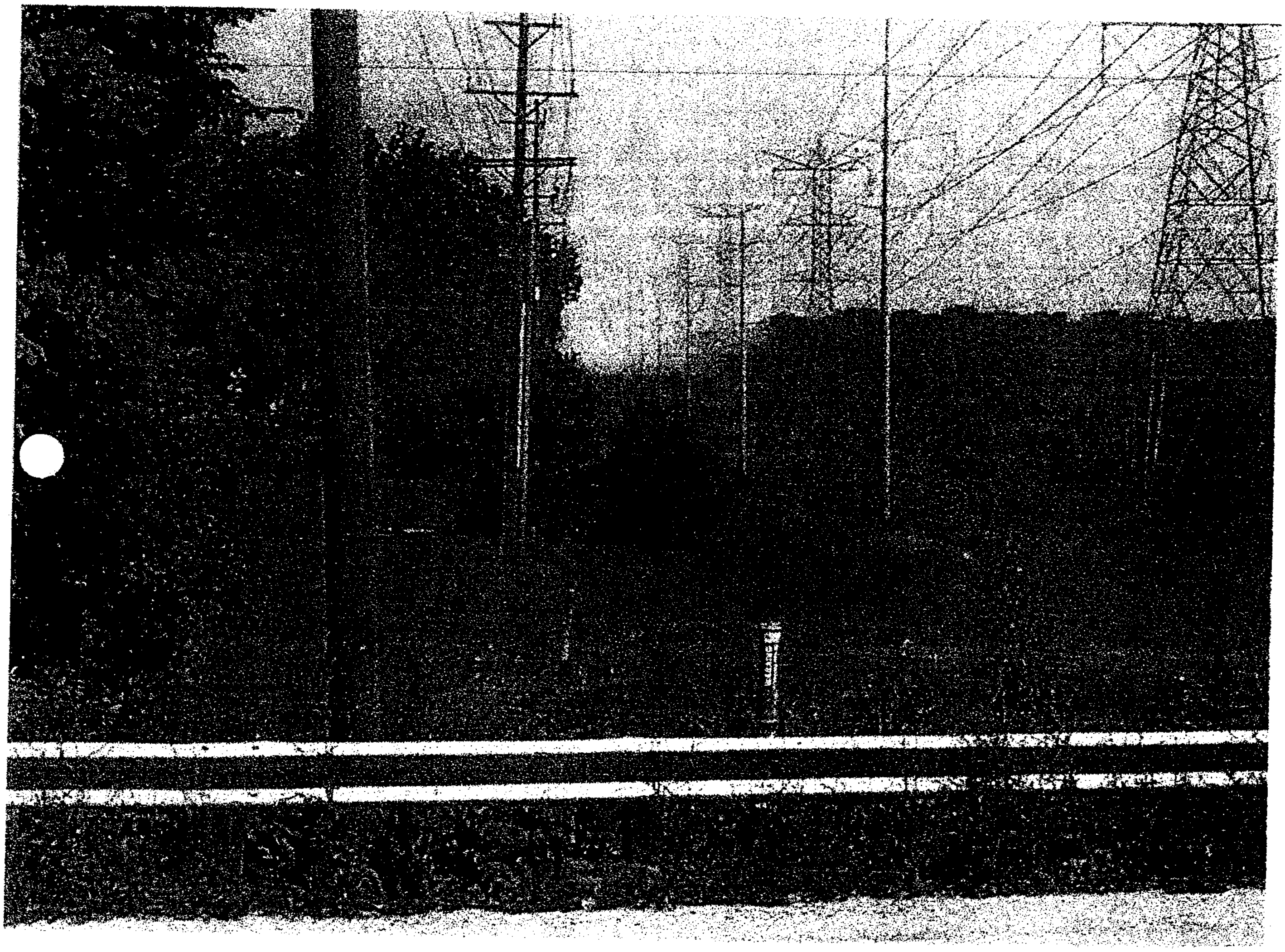
After



Before



After



(1)

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

LETTER OF CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 5, 2002

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5016C

Dear Mr. Tutcher:

On May 7 - May 18, 2001 and June 11 - June 12, 2001, a representative of the Central Region, Office of Pipeline Safety,(OPS) pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your Lakehead pipeline (LPL) records at Bay City, MI; Escanaba, MI; Ironwood, MI and Duluth, MN locations and field facilities located within the states of Michigan and Wisconsin.

The inspection disclosed the following items of concern. Please give these items your attention. Please note that the "(Crude System)" designations refer to OPS' nomenclature.

1. An open/close indicator rod on a LPL mainline valve was inoperable at the following location (Crude System #2):

   M/L Valve at MP1238.153 (Wolf Lake Road). The valve itself was in good working order.

2. During the field inspection OPS observed LPL's facilities had inadequate atmospheric protection at the following locations (Crude System #3):

   a. MP 465.500 Griffith Station - pipe at the ground interfaces on the suction and discharge sides of each pump unit.

   b. MP 341.351 (Line 6A) Walworth Station - pipe at the ground interfaces on the pipe inside the pressure control valve building.

3. During the field inspection OPS observed there were low pipe-to-soil (P/S) potentials at the following location (Crude System #3):

MP 500.137 Forrester Rd.
Line 6B: -0.820 volts
Line 6B Loop: -0.836 volts

4. During the field inspection OPS observed there is a possible shorted casing at the following location (Crude System #3):

MP 63.348 (Line 6A) - Possible casing problem indicated by P/S potentials.

5. During the field inspection OPS observed that rectifiers were not operative at the following locations (Crude System #3):

   a. MP 432.428 Parker Rd. - Rectifier C433 was not operative.

   b. MP 173.300 Marshfield Station - Rectifier C173A was not operative.

6. During the field inspection OPS observed that there is a possible rectifier problem at the following location (Crude System #3):

MP 30.900 - The output for rectifier 031 had dropped from the last time the rectifier was checked.

7. During the field inspection OPS observed that pressure recording procedures need improvement at the following location (Crude System #3):

   a. MP 148.541 Owen Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3.

   b. MP 135.555 Lublin Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3.

   c. MP 99.250 Ladysmith Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. There was a change in the labels that identify which pressures are being recorded in June, 1999. All charts stored prior to June, 1999 should be identified to indicate when the change occurred.

8. At Bay City the records need to reflect the location of pressure transmitters on Dwg. D-17-3.04-00099-9-581 (Line 17) at the Oregon metering and Segment "E" areas. These locations need to be added to the mechanical drawings also (Crude System #3).

9. At Fort Atkinson the records for three joints of emergency stock pipe stored at Fort Atkinson were inadequately marked to specifically track these joints to the hydrostatic test reports.

These items were discussed with your representatives during the inspection. They indicated that these items would receive attention.

The Office of Pipeline Safety appreciates your attention in these matters and good faith efforts to promote continued safety in your organization.

If we can answer any questions or be of any assistance, please contact us at (816) 329-3800. Thank you for your staff's cooperation during this scheduled inspection.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

Compl Reg Stewart
Phil

(2)

Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

September 16, 2002

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5016C

In response to your Letter of Concern to Enbridge dated June 5, 2002, I am pleased to report that all identified areas of concern have been addressed and corrected. These items were first identified during the May-June 2001 audits; therefore, many of them had already been corrected. We did, however, gather evidence of completion for each item listed in your letter, and have detailed supporting documents on file in our Duluth Office.

If you should have any further questions or concerns about any of the items referenced in your letter, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment – Letter of Concern
c/att: John Hayes
Greg Sevick
Tom Fridel
Mark Sitek
Dan Tutcher
Law Department

86

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

RECEIVED OCT 24 2006

October 23, 2006

Ivan A Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Room 462E
Kansas City MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

Pursuant to CPF No. 3-2002-5017H, Enbridge is required to notify the OPS by advising the Central Region Office and the Minnesota Office of Pipeline Safety of any and all leaks on the 34-inch pipeline, regardless of size.

Toward that end, this is to inform you that on October 20, 2006, Enbridge experienced a small leak (estimated to be 5 barrels) on Line 3 at milepost 927.5 upstream of Enbridge's Wilton Station. A call was received at approximately 12:00 MST reporting an odor in the vicinity and all pipelines in the right-of-way were shut down. Enbridge confirmed the leak at approximately 13:20 MST and initiated incident communications, including a call to the National Response Center (report #815505). Upon excavation, the cause of the leak was determined to be a crack in the side seam weld of a previously installed tight fitting sleeve. The defect has been repaired by installing an oversleeve. Brian Pierzina of the Minnesota Office of Pipeline Safety was on site during the assessment and repair phase of the incident.

This is an isolated incident unrelated to the concerns addressed in CPF No. 3-2002-5017H. The leak has been repaired and clean-up is underway. Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J Willoughby

c: Steve Irving
Leon Zupan
Brian Pierzina – MnOPS
Mark Sitek
Terrance McGill
Dave McNeill

U.S. Department
of Transportation

**Pipeline and
Hazardous Materia[ls]
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

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Dave Barrett

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Total Postage & Fees	$ 4.64

8-7-06
3-2002-5017H
Postmark Here CAO

Sent To Terrance McGill Enbridge Pipelines
Street, Apt. No.; or PO Box No. 1100 Louisiana, #3300
City, State, ZIP+4 Houston TX 77002

PS Form 3800, June 2002 See Reverse for Instructions

CERTIFIED MAI[L]

August 7, 2006

Mr. Terrance McGill
President
Enbridge Pipelines, LL[C]
1100 Louisiana
Suite 3300
Houston, TX 77002

RE: CPF No. 3-2002[...]
Line 3 – 34-inc[h] [...]
Restoration of [...]

Dear Mr. McGill:

The Pipeline and Hazar[...] received Mr. Mark Willoughby's lett[...] operating pressure on Enbridge's [...] [Cor]rective Action Order (Order) was issu[...] Minnesota. PHMSA has reviewed [...] [requ]est to lift the pressure restriction.

The supporting inform[...] [b]y the Return to Service Plan previousl[...] [b]y the integrity of the pipeline Enbridg[...] [...] and the Clearbrook to Superio[r] [...] [c]rack detection in-line inspection (ILI) [...] [be]en inspected in 2001 followed by exca[...] [...]ion was inspected in 2002. Ins[...] [comp]letion of numerous excavations [...] PHMSA reviewed the ILI result[...] [perform]ance accompanied by obser[...] [20]02 ILI was followed by a second [...] Clearbrook to Superior section. This [...] [pe]rformance and enhanced the understa[...]

SENDER: COMPLETE THIS SECTION
- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:
Terrance McGill
Enbridge Pipelines LLC
1100 Louisiana #3300
Houston, TX 77002

3-2002-5017H

COMPLETE THIS SECTION ON DELIVERY
A. Signature ☒ Agent ☐ Addressee
B. Received by (Printed Name) | C. Date of Delivery 8/10/06
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☒ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☒ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.
4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 3110 0004 0241 4192

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

8-5

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

August 7, 2006

Mr. Terrance McGill
President
Enbridge Pipelines, LLC
1100 Louisiana
Suite 3300
Houston, TX 77002

RE: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline
Restoration of Normal Operating Pressure

Dear Mr. McGill:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has received Mr. Mark Willoughby's letter of May 16, 2006, requesting restoration of normal operating pressure on Enbridge's Line 3, 34-inch pipeline. The above referenced Corrective Action Order (Order) was issued following the July 4, 2002 accident in Cohasset, Minnesota. PHMSA has reviewed the documentation Enbridge submitted with its request to lift the pressure restriction.

The supporting information documented the actions Enbridge took to satisfy the Return to Service Plan previously approved by PHMSA in December 2003. To verify the integrity of the pipeline Enbridge inspected the US Border to Clearbrook, Minnesota and the Clearbrook to Superior, Wisconsin sections of pipeline with an ultrasonic crack detection in-line inspection (ILI) tool. The US Border to Clearbrook section had been inspected in 2001 followed by excavations in 2002, and the Clearbrook to Superior section was inspected in 2002. Inspection tool performance was verified through completion of numerous excavations with associated repairs completed where necessary. PHMSA reviewed the ILI results and the excavation findings to confirm tool performance accompanied by observation of data gathered during excavations. The 2002 ILI was followed by a second ultrasonic crack detection inspection in 2005 on the Clearbrook to Superior section. This second tool confirmed the crack detection tool's performance and enhanced the understanding of crack growth on the pipeline.

Based on the results of the ILI data, operating pressure spectrum, and stress corrosion crack growth, Enbridge has determined re-inspection intervals for Line 3 using crack detection technology. The US Border to Clearbrook section is currently scheduled to be re-inspected in 2008, and the Clearbrook to Superior section is scheduled for 2010.

On a quarterly basis Kiefner and Associates performed an analysis of current operating pressure spectra to verify that planned inspection intervals continued to be appropriate. PHMSA understands that Enbridge will continue to monitor the pressure cycle data and perform a quarterly analysis as part of its integrity management program, and based on the results the re-inspection intervals may be reduced as needed.

In 2003 PHMSA approved restoration of operating pressure on the US Border to Clearbrook section of Line 3, and specified maintaining a 10% reduction in operating pressure on the Clearbrook to Superior section until Enbridge completed the 2005 in-line inspection. After completion of the tool run and associated repairs, Enbridge has proposed Base Maximum Discharge (BMD) pressures on the 34-inch Line 3 from Clearbrook to Superior as follows:

Clearbrook:	766 psig
Cass Lake:	610 psig
Deer River:	689 psig
Floodwood:	617 psig

Based on our review, PHMSA approves Enbridge's request to remove the previous operating pressure restrictions that were ordered. PHMSA understands that the BMD pressures may be adjusted over time due to changes in operating conditions, type of product transported, etc. In no case shall discharge pressures be set beyond the limits prescribed in the 49 CFR §195.406 regulation covering maximum operating pressures.

Thank you for submitting the required documentation. If you have any questions, please contact me or my staff.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

cc: Mr. Charles Kenow
Minnesota Office of Pipeline Safety

Mr. Mark Willoughby (via facsimile)
Enbridge – Superior, Wisconsin office

COPIES SENT TO:

Compliance Registry (3)

Initiating Engineer, Dave Barrett

Read File

Don Moore

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

October 23, 2006

RECEIVED OCT 2 4 2006

Ivan A Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Room 462E
Kansas City MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

Pursuant to CPF No. 3-2002-5017H, Enbridge is required to notify the OPS by advising the Central Region Office and the Minnesota Office of Pipeline Safety of any and all leaks on the 34-inch pipeline, regardless of size.

Toward that end, this is to inform you that on October 20, 2006, Enbridge experienced a small leak (estimated to be 5 barrels) on Line 3 at milepost 927.5 upstream of Enbridge's Wilton Station. A call was received at approximately 12:00 MST reporting an odor in the vicinity and all pipelines in the right-of-way were shut down. Enbridge confirmed the leak at approximately 13:20 MST and initiated incident communications, including a call to the National Response Center (report #815505). Upon excavation, the cause of the leak was determined to be a crack in the side seam weld of a previously installed tight fitting sleeve. The defect has been repaired by installing an oversleeve. Brian Pierzina of the Minnesota Office of Pipeline Safety was on site during the assessment and repair phase of the incident.

This is an isolated incident unrelated to the concerns addressed in CPF No. 3-2002-5017H. The leak has been repaired and clean-up is underway. Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J Willoughby

c: Steve Irving
Leon Zupan
Brian Pierzina – MnOPS
Mark Sitek
Terrance McGill
Dave McNeill

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Ave., S.E.
Washington, DC 20590

OCT 2 3 2007

Mr. Terry McGill
President
Enbridge Energy, LP
1100 Louisiana
Suite 3300
Houston, TX 77002

RE: CPF No. 3-2002-5017H

Dear Mr. McGill:

On July 5, 2002, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order to Enbridge Energy Company, Inc. requiring that certain actions be taken to ensure the safe operation of the portion of your 34-inch hazardous liquid pipeline designated as Line No. 4, running from the Canadian border to Superior, Wisconsin. The Director, Central Region, PHMSA has determined that all actions required by the Order (as amended) have been completed. Accordingly, this case is now closed. Thank you very much for your cooperation.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

cc: Mr. Ivan Huntoon
Director, Central Region, PHMSA

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

83

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

December 9, 2005

RECEIVED DEC 12 2005

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

As requested in your December 9, 2003 letter to Enbridge, two copies of the Kiefner & Associates reports pertaining to assessment of pressure cycles for Quarter 1 and Quarter 2 of 2005 are attached.

During Q1 of 2005, seven (7) investigative excavations were completed to conduct additional analysis of the 2002 inline inspection (ILI) crack run data. The information from these excavations was used to prepare for the 2005 ILI crack run, which was completed in Q2.

It's our understanding that a meeting will be held with your office on February 1, 2006 to discuss the Cohasset pressure restriction. We will provide additional information regarding the 2005 crack ILI results at that time.

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark Willoughby

Mark Willoughby

Attachments

c/att: Brian Pierzina
Joy Kadnar
Michael McGrath

Kiefner & Associates, Inc.

October 14, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3 Quarter 2 of 2005

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI Report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the second quarter of 2005.

The current analysis process was identical to that used for the previous quarterly analyses, the first quarter of 2004 (KAI Report 0023-0404), the second quarter of 2004 letter report and the June 2003 fatigue analysis (KAI Report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that while there was a decrease in the aggressiveness of the pressure cycles for the first quarter of 2005, the 2005 Quarter 2 cycles are similar in aggressiveness to the cycles that occurred in 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and

585 Scherers Court | Worthington, Ohio 43085 | Phone (614) 888-8220
www.kiefner.com | Fax (614) 888-7323

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 85.1 years was calculated using the 2005 Quarter 2 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by approximately 72 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 42 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

M.J. Rosenfeld /gw

Michael J. Rosenfeld
President
Senior Structural Engineer

MJR/CEK:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrpok 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Clearbrook 2005 Q2	***19.4***	***17.9***	***17.2***	***16.7***	***17.1***	***20.2***	***30.4***	***56.1***	***118.6***
	Clearbrook 2004 Q3	***19.6***	***18.1***	***17.1***	***17.1***	***17.1***	***20.1***	***30.7***	***55.9***	***117.9***
	Clearbrook 2004 Q4	***20.7***	***19.1***	***18.1***	***17.6***	***18.1***	***21.7***	***32.3***	***60.0***	***126.0***
	Clearbrook 2005 Q1	***26.8***	***24.6***	***23.6***	***22.9***	***23.3***	***27.8***	***41.8***	***77.0***	***162.6***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Deer River 2004 Q3	***10.1***	***9.6***	***9.1***	***8.6***	***9.3***	***12.6***	***21.9***	***44.1***	***96.8***
	Deer River 2005 Q2	***11.2***	***10.7***	***9.9***	***9.5***	***10.4***	***14.2***	***24.9***	***50.0***	***109.8***
	Deer River 2004 Q4	***11.6***	***10.6***	***10.1***	***9.6***	***10.6***	***14.1***	***24.7***	***49.9***	***108.9***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Deer River 2005 Q1	***15.6***	***14.8***	***14.0***	***13.4***	***14.5***	***20.0***	***35.0***	***70.5***	***154.7***
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Cass Lake 2004 Q4	***12.6***	***11.6***	***11.6***	***11.1***	***11.6***	***13.6***	***19.6***	***34.3***	***72.1***
	Cass Lake 2005 Q2	***13.0***	***11.7***	***11.5***	***11.4***	***11.9***	***13.7***	***19.4***	***34.0***	***71.2***
	Cass Lake 2004 Q3	***13.8***	***12.6***	***12.2***	***12.2***	***12.6***	***14.6***	***20.7***	***35.9***	***75.3***
	Floodwood 2004 Q2	***17.2***	***16.1***	***15.6***	***15.4***	***15.7***	***18.3***	***26.2***	***47.0***	***99.1***
	Cass Lake 2005 Q1	***20.6***	***18.6***	***18.2***	***18.1***	***18.7***	***21.7***	***30.5***	***53.4***	***111.8***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q3	***24.0***	***22.2***	***21.7***	***21.5***	***22.0***	***25.5***	***36.6***	***65.9***	***138.4***
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***
	Floodwood 2004 Q4	***28.2***	***26.2***	***25.6***	***25.2***	***25.7***	***30.1***	***43.4***	***78.0***	***164.3***
	Floodwood 2005 Q2	***31.9***	***29.8***	***29.1***	***28.6***	***29.3***	***34.0***	***48.7***	***87.6***	***184.3***
	Floodwood 2005 Q1	***47.1***	***43.9***	***42.9***	***42.1***	***42.9***	***49.5***	***70.5***	***126.2***	***265.1***

*Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2005 Quarter 1 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 4 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2098	161.4	130.3	191.0	204.6	263.7	192.1	19.4
MP 912.9	Transition to 0.344-inch WT	2088	145.1	117.2	171.8	184.0	237.2	172.7	23.2
MP 917.5	Transition to 0.312-inch WT	2089	146.4	118.2	173.3	185.5	239.2	174.4	32.4
MP 925.8	Transition to 0.281-inch WT	2118	194.3	157.2	230.3	246.5	317.8	231.7	61.3
Cass Lake	Cass Lake discharge pressures	2045	77.3	63.6	89.7	87.2	133.3	85.1	13.2
Deer River	Deer River discharge pressures	2086	145.6	113.1	148.2	166.9	238.3	168.9	21.3
MP 999.9	Transition to 0.312-inch WT	2077	128.8	100.0	131.1	147.7	210.7	149.5	26.3
MP 1007.2	Transition to 0.281-inch WT	2082	138.6	107.8	141.4	159.3	227.0	160.9	40.5
Floodwood	Floodwood discharge pressures	2112	165.5	117.8	165.2	195.6	315.4	219.4	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

Kiefner & Associates, Inc.

October 14, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3 Quarter 1 of 2005

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI Report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the first quarter of 2005.

The current analysis process was identical to that used for the previous quarterly analyses, the first quarter of 2004 (KAI Report 0023-0404), the second quarter of 2004 letter report and the June 2003 fatigue analysis (KAI Report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that there was a decrease in the aggressiveness of the pressure cycles for the first quarter of 2005 as compared to the pressure cycles that occurred in 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 133.3 years was calculated using the 2005 Quarter 1 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by approximately 120 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 66 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

M. J. Rosenfeld /gw

Michael J. Rosenfeld
President
Senior Structural Engineer

MJR/CEK:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Clearbrook 2004 Q3	***19.6***	***18.1***	***17.1***	***17.1***	***17.1***	***20.1***	***30.7***	***55.9***	***117.9***
	Clearbrook 2004 Q4	***20.7***	***19.1***	***18.1***	***17.6***	***18.1***	***21.7***	***32.3***	***60.0***	***126.0***
	Clearbrook 2005 Q1	***26.8***	***24.6***	***23.6***	***22.9***	***23.3***	***27.8***	***41.8***	***77.0***	***162.6***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Deer River 2004 Q3	***10.1***	***9.6***	***9.1***	***8.6***	***9.3***	***12.6***	***21.9***	***44.1***	***96.8***
	Deer River 2004 Q4	***11.6***	***10.6***	***10.1***	***9.6***	***10.6***	***14.1***	***24.7***	***49.9***	***108.9***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Deer River 2005 Q1	***15.6***	***14.8***	***14.0***	***13.4***	***14.5***	***20.0***	***35.0***	***70.5***	***154.7***
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Cass Lake 2004 Q4	***12.6***	***11.6***	***11.6***	***11.1***	***11.6***	***13.6***	***19.6***	***34.3***	***72.1***
	Cass Lake 2004 Q3	***13.8***	***12.6***	***12.2***	***12.2***	***12.6***	***14.6***	***20.7***	***35.9***	***75.3***
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* Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2005 Quarter 1 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 4 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2134	161.4	130.3	191.0	204.6	263.7	19.4
MP 912.9	Transition to 0.344-inch WT	2121	145.1	117.2	171.8	184.0	237.2	23.2
MP 917.5	Transition to 0.312-inch WT	2122	146.4	118.2	173.3	185.5	239.2	32.4
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Cass Lake	Cass Lake discharge pressures	2069	77.3	63.6	89.7	87.2	133.3	13.2
Deer River	Deer River discharge pressures	2121	145.6	113.1	148.2	166.9	238.3	21.3
MP 999.9	Transition to 0.312-inch WT	2107	128.8	100.0	131.1	147.7	210.7	26.3
MP 1007.2	Transition to 0.281-inch WT	2116	138.6	107.8	141.4	159.3	227.0	40.5
Floodwood	Floodwood discharge pressures	2160	165.5	117.8	165.2	195.6	315.4	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

Kiefner & Associates, Inc.

PIPELINE INTEGRITY

OCT 24 2005

October 14, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
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Canada

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Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that there was a decrease in the aggressiveness of the pressure cycles for the first quarter of 2005 as compared to the pressure cycles that occurred in 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 133.3 years was calculated using the 2005 Quarter 1 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by approximately 120 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 66 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

M. J. Rosenfeld /gw

Michael J. Rosenfeld
President
Senior Structural Engineer

MJR/CEK:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Clearbrook 2004 Q3	***19.6***	***18.1***	***17.1***	***17.1***	***17.1***	***20.1***	***30.7***	***55.9***	***117.9***
	Clearbrook 2004 Q4	***20.7***	***19.1***	***18.1***	***17.6***	***18.1***	***21.7***	***32.3***	***60.0***	***126.0***
	Clearbrook 2005 Q1	***26.8***	***24.6***	***23.6***	***22.9***	***23.3***	***27.8***	***41.8***	***77.0***	***162.6***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Deer River 2004 Q3	***10.1***	***9.6***	***9.1***	***8.6***	***9.3***	***12.6***	***21.9***	***44.1***	***96.8***
	Deer River 2004 Q4	***11.6***	***10.6***	***10.1***	***9.6***	***10.6***	***14.1***	***24.7***	***49.9***	***108.9***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Deer River 2005 Q1	***15.6***	***14.8***	***14.0***	***13.4***	***14.5***	***20.0***	***35.0***	***70.5***	***154.7***
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Cass Lake 2004 Q4	***12.6***	***11.6***	***11.6***	***11.1***	***11.6***	***13.6***	***19.6***	***34.3***	***72.1***
	Cass Lake 2004 Q3	***13.8***	***12.6***	***12.2***	***12.2***	***12.6***	***14.6***	***20.7***	***35.9***	***75.3***
	Floodwood 2004 Q2	***17.2***	***16.1***	***15.6***	***15.4***	***15.7***	***18.3***	***26.2***	***47.0***	***99.1***
	Cass Lake 2005 Q1	***20.6***	***18.6***	***18.2***	***18.1***	***18.7***	***21.7***	***30.5***	***53.4***	***111.8***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q3	***24.0***	***22.2***	***21.7***	***21.5***	***22.0***	***25.5***	***36.6***	***65.9***	***138.4***
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***
	Floodwood 2004 Q4	***28.2***	***26.2***	***25.6***	***25.2***	***25.7***	***30.1***	***43.4***	***78.0***	***164.3***
	Floodwood 2005 Q1	***47.1***	***43.9***	***42.9***	***42.1***	***42.9***	***49.5***	***70.5***	***126.2***	***265.1***

* Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2005 Quarter 1 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 4 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2134	161.4	130.3	191.0	204.6	263.7	19.4
MP 912.9	Transition to 0.344-inch WT	2121	145.1	117.2	171.8	184.0	237.2	23.2
MP 917.5	Transition to 0.312-inch WT	2122	146.4	118.2	173.3	185.5	239.2	32.4
MP 925.8	Transition to 0.281-inch WT	2161	194.3	157.2	230.3	246.5	317.8	61.3
Cass Lake	Cass Lake discharge pressures	2069	77.3	63.6	89.7	87.2	133.3	13.2
Deer River	Deer River discharge pressures	2121	145.6	113.1	148.2	166.9	238.3	21.3
MP 999.9	Transition to 0.312-inch WT	2107	128.8	100.0	131.1	147.7	210.7	26.3
MP 1007.2	Transition to 0.281-inch WT	2116	138.6	107.8	141.4	159.3	227.0	40.5
Floodwood	Floodwood discharge pressures	2160	165.5	117.8	165.2	195.6	315.4	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

October 14, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3 Quarter 2 of 2005

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI Report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the second quarter of 2005.

The current analysis process was identical to that used for the previous quarterly analyses, the first quarter of 2004 (KAI Report 0023-0404), the second quarter of 2004 letter report and the June 2003 fatigue analysis (KAI Report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that while there was a decrease in the aggressiveness of the pressure cycles for the first quarter of 2005, the 2005 Quarter 2 cycles are similar in aggressiveness to the cycles that occurred in 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 85.1 years was calculated using the 2005 Quarter 2 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by approximately 72 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 42 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

M.J. Rosenfeld /gw

Michael J. Rosenfeld
President
Senior Structural Engineer

MJR/CEK:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	1.6	1.5	1.4	1.4	1.5	1.8	2.8	5.3	11.4
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	13.2	12.1	11.6	11.2	11.5	13.7	20.6	38.0	80.4
	Clearbrook 2004 Q1	16.3	15.0	15.0	14.3	14.3	17.0	25.8	47.2	99.6
	Clearbrook 2005 Q2	19.4	17.9	17.2	16.7	17.1	20.2	30.4	56.1	118.6
	Clearbrook 2004 Q3	19.6	18.1	17.1	17.1	17.1	20.1	30.7	55.9	117.9
	Clearbrook 2004 Q4	20.7	19.1	18.1	17.6	18.1	21.7	32.3	60.0	126.0
	Clearbrook 2005 Q1	26.8	24.6	23.6	22.9	23.3	27.8	41.8	77.0	162.6
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	Deer River 2000 Q1	1.0	1.0	1.0	1.0	1.1	1.5	2.8	5.7	12.5
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	7.5	7.1	6.6	6.4	6.9	9.5	16.6	33.5	73.5
	Deer River 2004 Q1	10.0	9.5	9.0	8.6	9.1	12.5	21.8	43.6	95.2
	Deer River 2004 Q3	10.1	9.6	9.1	8.6	9.3	12.6	21.9	44.1	96.8
	Deer River 2005 Q2	11.2	10.7	9.9	9.5	10.4	14.2	24.9	50.0	109.8
	Deer River 2004 Q4	11.6	10.6	10.1	9.6	10.6	14.1	24.7	49.9	108.9
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Deer River 2005 Q1	15.6	14.8	14.0	13.4	14.5	20.0	35.0	70.5	154.7
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	1.6	1.5	1.5	1.5	1.6	1.9	2.9	5.3	11.4
	Cass Lake 2000 Q1	1.9	1.7	1.6	1.6	1.7	2.0	2.9	5.1	10.8
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	9.6	8.6	8.5	8.5	8.7	10.2	14.3	25.3	53.1
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	11.5	10.0	10.0	10.0	10.5	12.0	17.5	30.4	63.8
	Cass Lake 2004 Q4	12.6	11.6	11.6	11.1	11.6	13.6	19.6	34.3	72.1
	Cass Lake 2005 Q2	13.0	11.7	11.5	11.4	11.9	13.7	19.4	34.0	71.2
	Cass Lake 2004 Q3	13.8	12.6	12.2	12.2	12.6	14.6	20.7	35.9	75.3
	Floodwood 2004 Q2	17.2	16.1	15.6	15.4	15.7	18.3	26.2	47.0	99.1
	Cass Lake 2005 Q1	20.6	18.6	18.2	18.1	18.7	21.7	30.5	53.4	111.8
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q3	24.0	22.2	21.7	21.5	22.0	25.5	36.6	65.9	138.4
	Floodwood 2004 Q1	24.4	22.4	21.9	21.9	22.4	25.9	36.9	66.3	139.1
	Floodwood 2004 Q4	28.2	26.2	25.6	25.2	25.7	30.1	43.4	78.0	164.3
	Floodwood 2005 Q2	31.9	29.8	29.1	28.6	29.3	34.0	48.7	87.6	184.3
	Floodwood 2005 Q1	47.1	43.9	42.9	42.1	42.9	49.5	70.5	126.2	265.1

*Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2005 Quarter 1 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 4 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2005 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2098	161.4	130.3	191.0	204.6	263.7	192.1	19.4
MP 912.9	Transition to 0.344-inch WT	2088	145.1	117.2	171.8	184.0	237.2	172.7	23.2
MP 917.5	Transition to 0.312-inch WT	2089	146.4	118.2	173.3	185.5	239.2	174.4	32.4
MP 925.8	Transition to 0.281-inch WT	2118	194.3	157.2	230.3	246.5	317.8	231.7	61.3
Cass Lake	Cass Lake discharge pressures	2045	77.3	63.6	89.7	87.2	133.3	85.1	13.2
Deer River	Deer River discharge pressures	2086	145.6	113.1	148.2	166.9	238.3	168.9	21.3
MP 999.9	Transition to 0.312-inch WT	2077	128.8	100.0	131.1	147.7	210.7	149.5	26.3
MP 1007.2	Transition to 0.281-inch WT	2082	138.6	107.8	141.4	159.3	227.0	160.9	40.5
Floodwood	Floodwood discharge pressures	2112	165.5	117.8	165.2	195.6	315.4	219.4	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

Compl Key Phil
Stewart
Ivan

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

December 9, 2005

RECEIVED DEC 12 2005

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

As requested in your December 9, 2003 letter to Enbridge, two copies of the Kiefner & Associates reports pertaining to assessment of pressure cycles for Quarter 1 and Quarter 2 of 2005 are attached.

During Q1 of 2005, seven (7) investigative excavations were completed to conduct additional analysis of the 2002 inline inspection (ILI) crack run data. The information from these excavations was used to prepare for the 2005 ILI crack run, which was completed in Q2.

It's our understanding that a meeting will be held with your office on February 1, 2006 to discuss the Cohasset pressure restriction. We will provide additional information regarding the 2005 crack ILI results at that time.

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark Willoughby

Attachments

c/att: Brian Pierzina
Joy Kadnar
Michael McGrath

(16) Copies Reg Dave Joshua
Ivan Allan

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

December 2, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: Request for relief from operating pressure restrictions, CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 3 System. The Order was issued in response to a failure that occurred on the line on July 4, 2002, and applied to Enbridge's 34-inch pipeline system constructed with pipe manufactured by U.S. Steel. On July 11, 2002, the Order was amended to allow Enbridge to return the pipeline to service provided the operating pressure at the failure location and at certain pump stations did not exceed 80% of the pressure at those locations at the time of the failure. The amendment further stipulated that these pressure restrictions would remain in effect until written approval for an increase was granted by the Central Region Director.

By letter dated November 11, 2002, and in subsequent discussions with staff, Enbridge has provided additional information on its operations and past pressure history and requested that the operating pressure restrictions be limited to 85% of a higher operating pressure recorded preceding the failure as an interim measure pending review and approval of the full return-to-service plan. The higher maximum operating pressures were requested for the pipeline sections from Gretna to Clearbrook to alleviate operational difficulties being experienced at the lower pressure limits.

We have reviewed the Enbridge request. We will not approve your request to operate at the 85% level. However, we find that it is reasonable to allow Enbridge to operate at 80% of the higher operating pressures recorded prior to the failure at the requested locations. Therefore, we are amending the maximum operating pressures for Line 3 upstream of Clearbrook as follows:

Station	Pressure
Gretna	437 psig
Donaldson	494 psig
Plummer	442 psig

We further request that Enbridge provide the Central Region Office a tabulation of the occurrences in which these maximum operating pressures are exceeded. The information should include the dates, pressures and cause of the occurrence and should be submitted on a weekly basis.

This approval is with the understanding that OPS and MNOPS will continue to review additional pressure restrictions and/or other measures that may be required as a result of new information provided by the analysis of the failed pipe section and new information on any other items that may have been contributing factors to the failure.

If you have any questions in regard to this matter, please contact me at (816) 329-3800.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

Mr. Charles Kenow, MnOPS

Copies to
Dave
Phil

15

Huntoon, Ivan (OPSKC)

From: Jay.Johnson@enbridge-us.com
Sent: Tuesday, November 26, 2002 1:00 PM
To: Huntoon, Ivan <RSPA>
Cc: John.Sobojinski@enbridge-us.com; Christine.Neff@cnpl.enbridge.com; Allan.Baumgartner@cnpl.enbridge.com; David.Bryson@cnpl.enbridge.com
Subject: Line 3 Operational info and conf call number ...

Microsoft Word 4 Excel 2.x Chart

Hi Ivan,

I've attached the latest info you requested and will also fax them. For the conference call this afternoon we'll use a dial in number.

800 / 503 - 2899 access code 7250512. If you have any trouble with this number please call Janice @ 218 / 725 - 0541.

Talk to you later, Jay

(See attached file: Line 3b Operations description.doc)(See attached file: Line 3 Excersions.xls)

Enbridge operates Line 3b (34") from Cromer, Manitoba, Canada to Superior, Wisconsin. It transports a wide variety of crude types ranging in density from light to heavy crude in a batched operation. The line operates at a variety of flow rates depending upon crude supply and shipper requirements.

There are several significant elevation changes, which greatly impact the operation of this line. Clearbrook Terminal is a location where crude is received and delivered with Line 3b. These factors all combine to result in pressures at various locations along the line changing significantly over relatively short periods of time.

In reviewing Line 3b operations in the 3 months prior to the release, the discharge pressure profile at Gretna is similar for each month. There are significant variations in pressure and the line reaches the maximum pressure once or twice within these months. The average operating pressure is approximately 200 psig lower than the highest pressure. A wide variation between regular operation and the maximum allowables is required due to the elevation drop coming in to Gretna. The line is regularly operated at pressures that are significantly lower than the maximums, which allows enough operational room so that the limits are not exceeded during operational maneuvers or line upsets. The operating profile we see at Gretna is as expected given the location of the Station and we expect it will continue in a similar manner moving up and or down with the allowable discharge pressure.

The maximum pressures reached during the 3 months prior to the release were for short durations and on relatively few occasions. This explains why the maximum pressures were only seen for a combined 2 hours. The average operating pressures are consistently significantly lower than the maximum pressures. Our current and future operations will see similar pressure signatures with the highest pressures at or near the maximum operating limits being attained infrequently for short durations while the average operating pressures will remain significantly (200 psig) below the maximum.

Line 3 is a complex line with many product types, line rates, operational maneuvers required and challenging geography. The reduced BMDP under which we are currently operating is significantly lower than the previous limits. The characteristics of this line are such that typical operations would be well below limits with the operational room in place to accommodate regular line operational changes and minor upsets. In order to operate under the current pressure limits, there have been changes in the operating approach to narrow the operational range in an effort to maintain pressures below the current limits.

Occurrences in which current BMDP was exceeded by less than 10% - Gretna to Superior

Line #	Date/Station	Comments
3	July 27/02-GF,	Pressure backed into Gretna after a High Holding Pressure shutdown at Superior
3	July25-DN, Aug.4-DN	Occurred during a change of units at DN
3	July30-GF, Aug.7-PL, Aug.8-PL, Aug.27-GF, Sept.3-PL, Sept.4-PL, Sept.8-PL, Sept.25-PL, Sept.28-GF, Sept.28-PL, Sept.29-PL, Oct.4-GF, Oct.17-PL, Oct.27-GF, Oct.30-GF, Nov.1-GF,Nov.3-GF, Nov.10-GF	Occurred during non steady state conditions (line startups/shutdowns etc.) associated with the beginning or ending of full stream injections/deliveries at Clearbrook.
3	Aug.28-GF, Sept.18-GF	Occurred after the loss of PL & DN units due to electrical storm causing pressure to back into GF.
4	Sept.1-MP1002	Occurred during a line startup QU to PW. FW 3.2 did not start causing pressure to back up.
4	Sept.3-MP1002	Plugged strainer on PCV at PW caused pressure to backup.
4	Sept.26-CR	Occurred during the start of a full stream delivery/injection at CR. PCV reacted too slow when boosters started.
3	Oct.2-MP1002 & GF	Occurred while increasing line rate. MP 1002 bumped briefly over pressure shutting the line down.
4	Oct.8-FW	Occurred during a FW unit start. PCV did not react quick enough.
3	Oct.10-CR, PL & GF	Line blockage at CR on a line startup due to error in valving configuration on new line activation.
3	Oct.12-CR	Line blockage at MP 909.43 due to SCADA related problem during new line activation.
3	Oct.19-PL, Oct.21-PL&GF, Oct.23-PL&GF, Nov.15-PL	Occurred during a unit start/change at CR when both running units dropped off causing pressure to back into PL.
3	Nov.12-GF & PL	Occurred when CR station was lost on a pig bypass causing pressure to backup into Plummer and Gretna.

Note: Occurrences in which BMDP was exceeded by less than 2% are not included in chart above.

Occurrences in which current BMDP was exceeded by more than 10% - Gretna to Superior

Line #	Date/Station	Comments
3	July10-GF, Aug.19-GF	Pressure backed into Gretna after a High Holding Pressure shutdown at Superior
3	Oct.12-GF&PL	Line blockage at MP 909.43 due to SCADA related problem during new line activation.
3	Nov.18-PL	Occurred when CR units were lost on a CR unit start causing pressure to back into PL.

BMDP	Base Maximum Discharge Pressure	
CR	Clearbrook	
DN	Donaldson	
FW	Floodwood	
GF	Gretna	
MP	Milepost	
PCV	Pressure Control Valve	
PL	Plummer	
PW	Superior	
QU	Regina	

(18)

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National Transportation Safety Board
Washington, D.C. 20594

November 26, 2002

TO: Party Representatives-Distribution list below

Subject: Materials Laboratory Factual Report #02-102
Crude Oil Pipeline Rupture, Cohasset Minnesota, DCA02-MP002

Dear Party Representative:

Enclosed is a copy of the National Transportation Safety Board Materials Laboratory Factual Report #02-102 for this accident. This report is only for the use of the parties at this time and is not to be made available to the public until the National Transportation Safety Board releases it in its public docket.

If you have any questions regarding this matter, feel free to call me at 202-314-6468. Your participation and cooperation in this investigation is appreciated.

Sincerely Yours,

Cliff Zimmerman
Investigator-In-Charge

Distribution list:

NATIONAL TRANSPORTATION SAFETY BOARD

Office of Research and Engineering
Materials Laboratory Division
Washington, D.C. 20594

month/day/year

MATERIALS LABORATORY FACTUAL REPORT Report No. 02-102

A. ACCIDENT

Place	: Cohasset, Minnesota
Date	: July 4, 2002
Vehicle	: 34 inch Crude Oil Pipeline
Operator	: Enbridge Pipelines (Lakehead) L.L.C.
NTSB No.	: DCA02MP002
Investigator	: Cliff Zimmerman

B. COMPONENTS EXAMINED

Two 15 foot sections of 34 Inch Diameter Crude Oil Pipe from Line 4

C. DETAILS OF THE EXAMINATION

Two 15-foot sections of 34-inch diameter pipe were received. Both were reportedly adjacent sections from the same original manufactured length of pipe. Both contained a longitudinal seam weld but neither had a girth weld. One section had a longitudinal rupture while the other section was intact and reportedly removed from the line downstream of the ruptured section. Spiral wrapped tape coatings were present on the outer diameters of both sections.

The pipeline was reported to be a 34 inch nominal diameter pipe per API 5L grade X52 with a 0.312 inch nominal wall thickness. It had specified minimum yield strength of 52,000 psi and was originally manufactured by US Steel in 1967 using a double submerged arc seam weld. The pipe sections were originally located at mile post 1002.73 approximately 7 miles downstream of a pump station.

As-received the two sections of pipe appeared undamaged (no dents, scratches or gouges), straight and round, except at the rupture. The spiral wrapped coating was intact and appeared continuous except surrounding the rupture. Some surface corrosion was visually noted on the outer surface of the pipe adjacent to the weld bead in the central region of the rupture. The corrosion was assessed as light (no visually apparent pitting and little apparent loss of wall thickness). At the upstream end, the pipe outer diameter measured 34 5/16 inches adjacent to the seam weld and 33 ¾ inches at 90° to the weld. On the downstream end of the rupture, the diameters both measured 34 inches. The upstream pipe wall thickness as measured with point micrometers ranged from 0.301 to 0.305 inch. The downstream end measured from 0.294 to 0.309 inch. Both measurement areas were within the requirements of API 5LX[1]. Both pipe sections were ultrasonically inspected for cracks along the weld seam. The inspections were performed by an independent inspection service and no discontinuities were uncovered outside of the immediate rupture area.

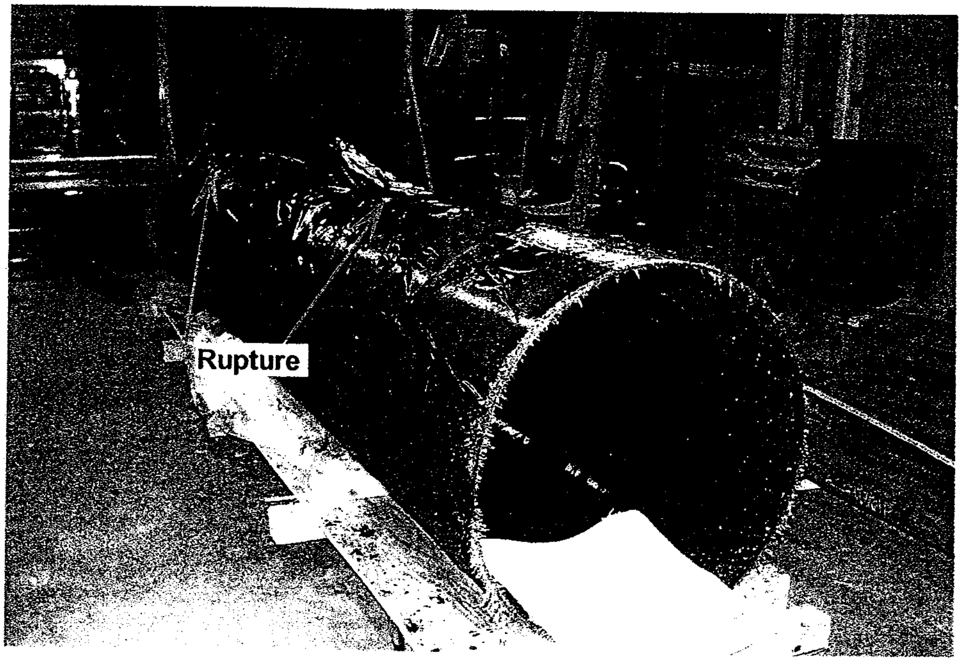
The ruptured section of pipe contained a longitudinal split adjacent to the seam weld as shown in figure 1. The split measured 69 inches long and was roughly centered in the received section of pipe. The mating faces of the separation were gapped open about 6.25 inches at the center and both sides were deformed outward. As installed in the pipeline, the seam weld was reported to be at the 5:30 position when looking downstream. In this orientation, the rupture was on the 6:00 side of the weld.

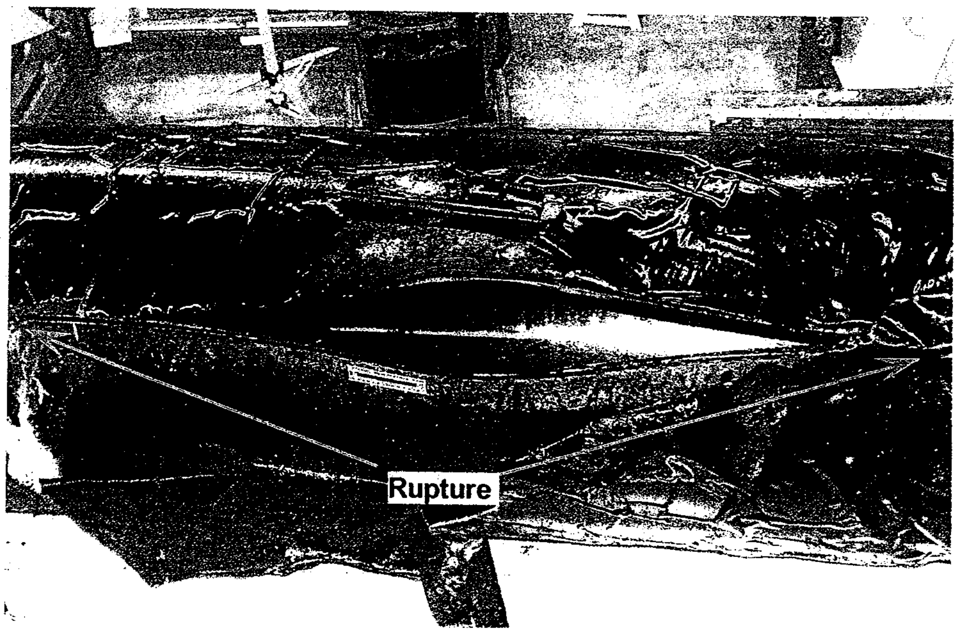
For most of its length, the split ran slightly (0.25 to 0.75 inch) away from the edge of the weld on both the inner and outer surfaces of the pipe. However, for about 13 inches at the center of the rupture the crack ran along the toe of the inner weld bead and close to the outer weld, see figure 2. Except in this central region, the fracture displayed an approximate 45° slant fracture consistent with ductile tensile overstress separation. In the central region, a large portion of the fracture adjacent to the inner diameter was flat and perpendicular to the pipe wall. Preliminary cleaning of the fracture surface with acetone revealed multiple arrest lines in the flat region and other indications of a progressive cracking from the inner surface. The progressive areas followed the toe of the inner weld bead. At the center of the flat region the progressive cracking nearly penetrated through the pipe wall over a 2 to 3 inch broad front, as shown in figure 3, but rapidly thinned to either side. At the extreme ends, the flat portion of the fracture extended about 0.01 inches into the pipe.

An approximate 10-inch long section of the central region of the rupture was saw cut from the weld side fracture. A smaller section was also cut from the mating area of the other side of the fracture. Both sections were cleaned in acetone and visually examined. Magnified optical examinations found fatigue progression features on the entire area of flat fracture. The fatigue emanated from the inner surface of the pipe at the toe of the weld. A multitude of ratchet marks were visible all along the weld toe area indicating multiple fatigue initiation sites and initial growth from the entire 13-inch length of the flat fracture area (see figure 4). Further examination of the cleaned fracture found a darker, more heavily oxidized band paralleling the interior surface of the pipe. The band was about 0.04 inch wide in the central region of the fracture and contained a prominent arrest line that also paralleled the inner surface of the pipe. The oxidized band and arrest line were visible for almost the entire length of the fatigue area. In the central region of the fracture the arrest line was between 0.025 and 0.030 inch from the interior surface of the pipe. The oxidized band is visible in the lower view of figure 4 and at high magnification in both views of figure 5 with the arrest line denoted.

---

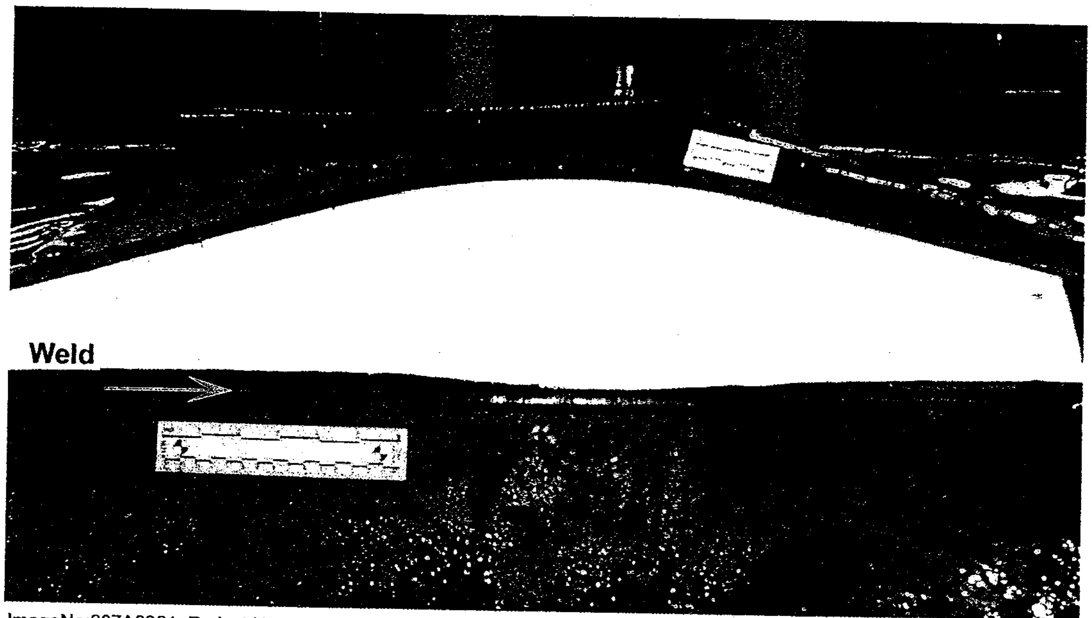
[1] API 5LX, 19th Edition, March 1073, table 6.2 allows wall thickness variations of +19.5% and –8.0% from nominal. For 0.312 inch nominal wall the range is 0.373 to 0.287 inch.





ImageNo: 207A0300, Project No:A00403

Figure 1--Two views of the ruptured section of pipe. Upper view shown looking downstream with the pipe rotated from it's reported installed orientation. The lower view shows the rupture area from the side with flow from right to left.



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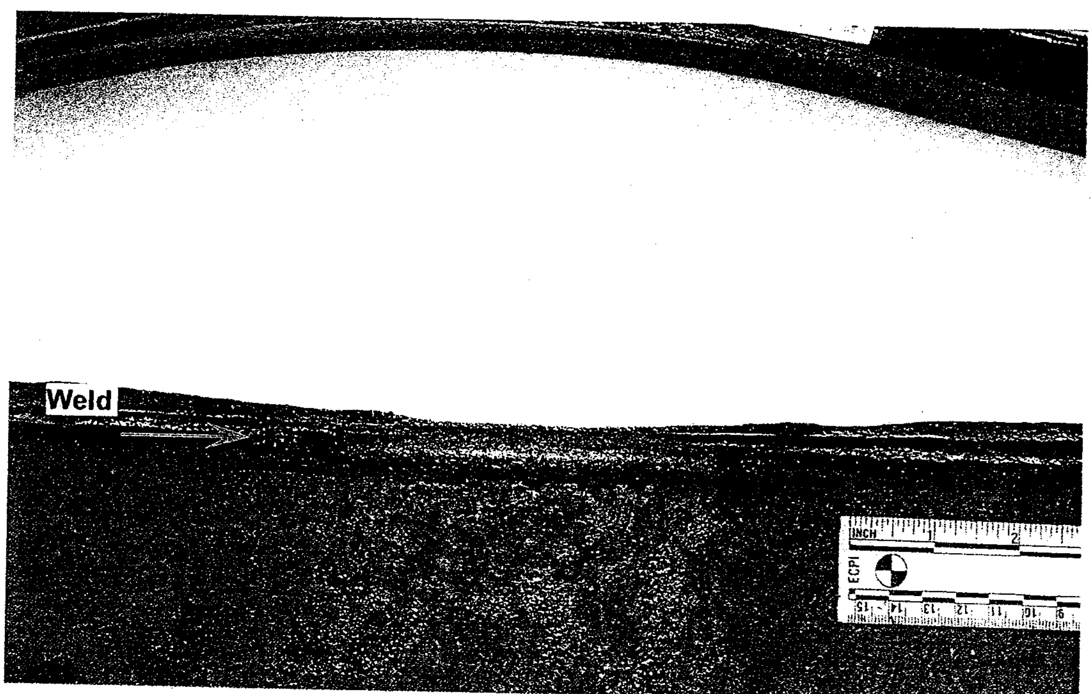
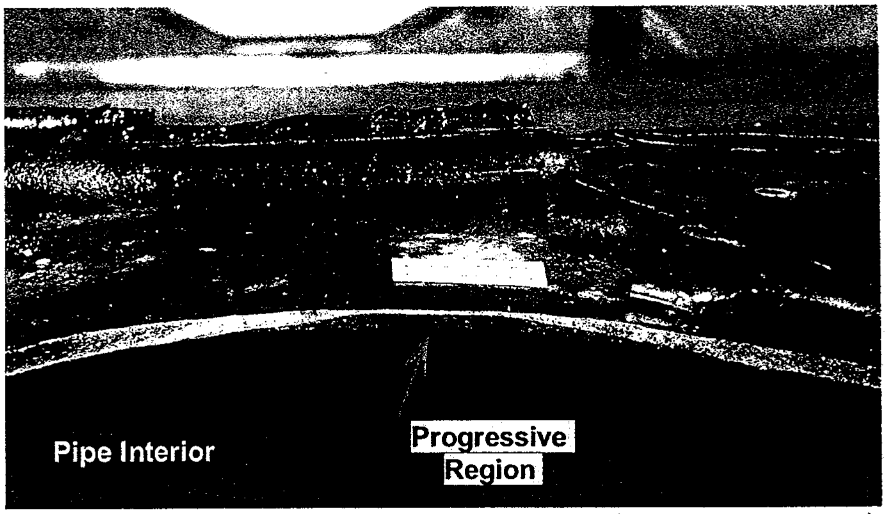
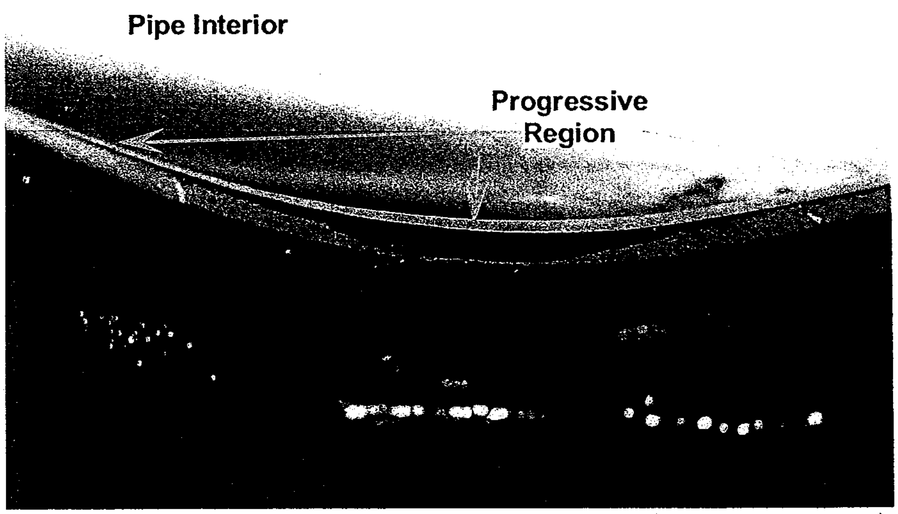


ImageNo: 207A0325, Project No:A00403 — 100 mm

Figure 2--Closer view of the rupture showing it's relationship to the seam weld.

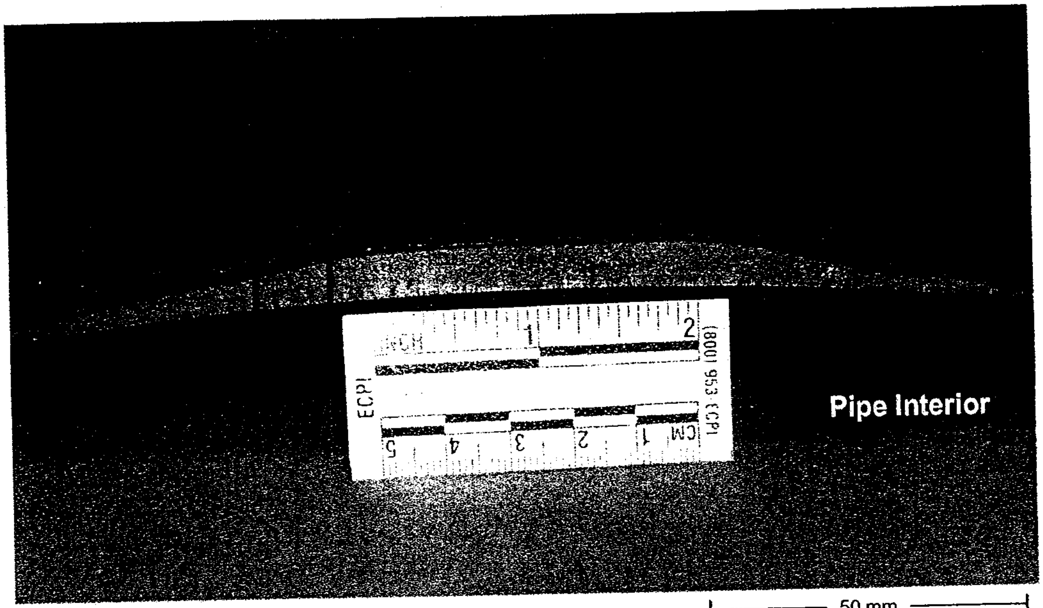


ImageNo:207A0315, Project No:A00403 — 100 mm

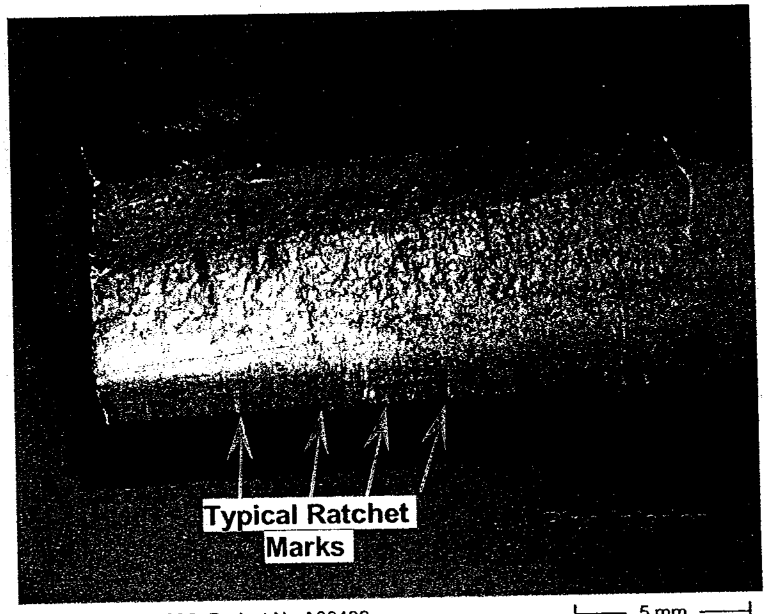


ImageNo: 207A0326, Project No:A00403 — 50 mm

Figure 3--Two views of the progressive region of the rupture. The upper view shows the fracture face without the weld. The lower view is the mating area of the fracture face with the weld. The progressive area shows dark in both views.

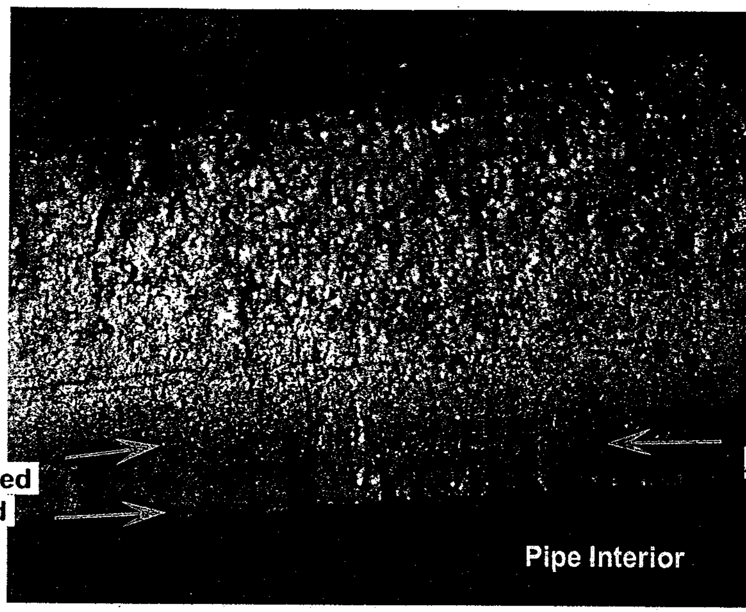


ImageNo:207A0388, Project No:A00403 ├── 50 mm ──┤



ImageNo: 207A0392, Project No:A00403 ├── 5 mm ──┤

Figure 4--Two views of the weld side fracture face after cleaning in acetone. The upper view shows the central region of the fatigue. Lower view is from the boxed area of the upper view. The metallographic section shown in figure 6 was taken from the left edge of the pipe section shown in the lower view.



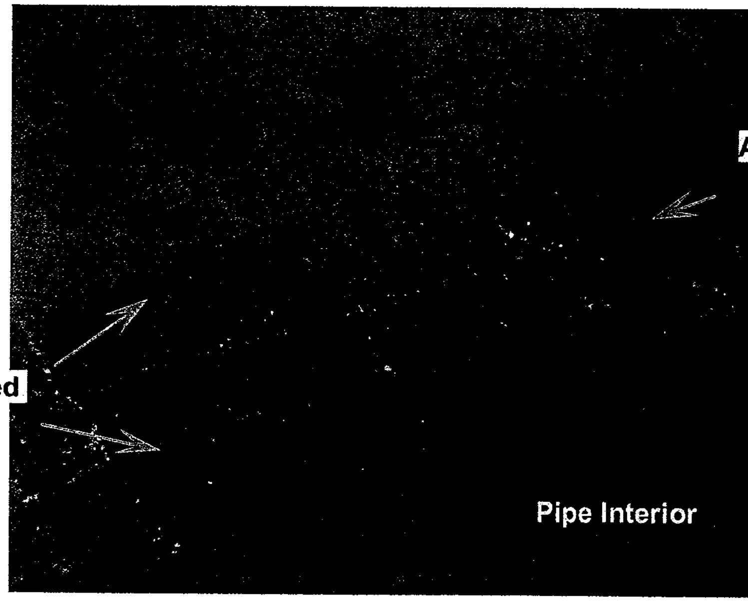
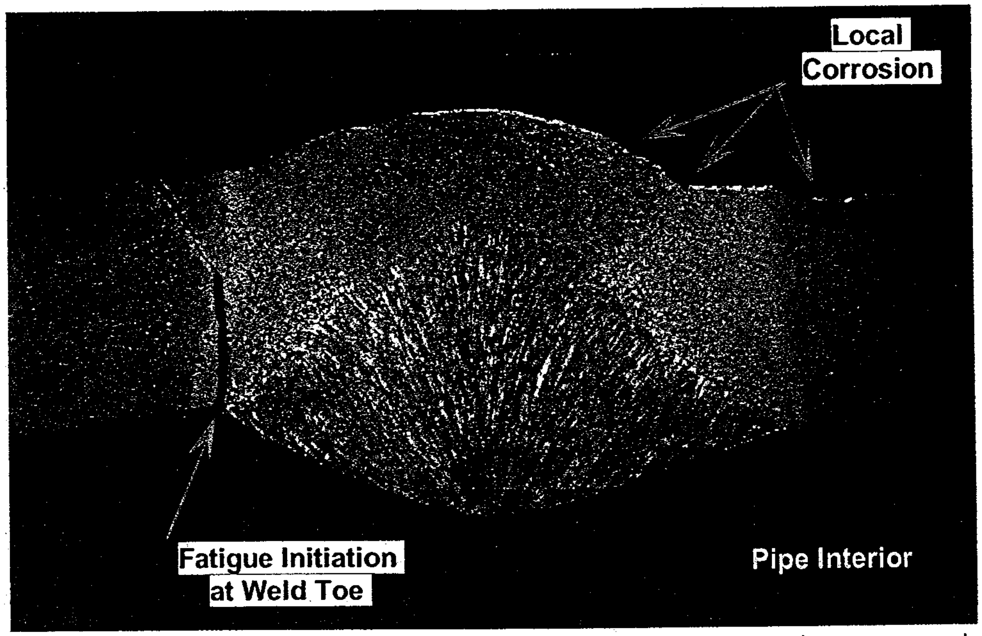


Figure 5--Closer views of the oxidized band adjacent to the pipe interior and the arrest line. At slightly different orientations and magnifications.



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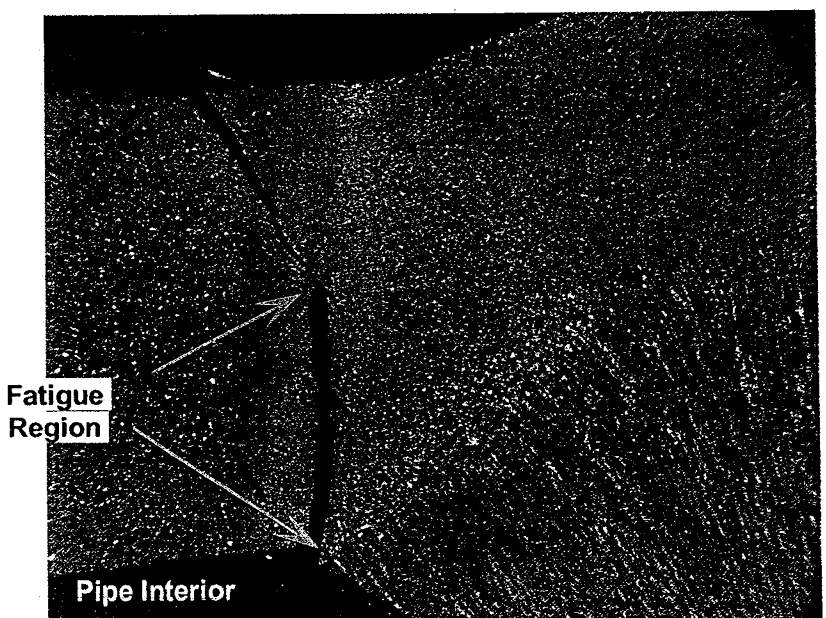
5 mm



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2 mm

Figure 6--Two views showing the fatigue initiating at the toe of the weld on the interior surface of the pipe on a metallographic section. The weld beads, heat affected zones and base metal are visible. 2% Nital etch

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June 3, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 seconds	Pressure backed up when a Floodwood unit was stopped due to a power consumption.
05/19/03	PL	466 psig	5.42%	53 seconds	Sediment plugged the Clearbrook transmitter line causing a faulty reading.

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

(44)

Original filed in binder

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May 6, 2003

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

On April 29, 2003, we sent you a binder containing responses to all outstanding requests for information from your department. After mailing this document to you, we realized that an error had not been corrected during the initial review. Toward that end, attached are replacement pages for Tab 18.1 to be inserted into the binder.

We apologize for this inconvenience, and look forward to a favorable response from you soon. As always, should you have any questions or concerns, please contact me at your convenience.

Sincerely,

For JRS

John R. Sobojinski

Attachment

c: H. Noel Duckworth
John Hayes
Joel Kanvik
Walter Kresic
Art Meyer
Greg Sevick
Dan Tutcher
Ron Wiest

U.S. DOT Information Request - CPF 3-2002-5017H
April 25, 2003

DOT Question #18

Complete documentation of the Clearbrook to Superior inspection digs which were completed as a result of the PII UltraScan CD tool run of 2002; including, but not limited to, the UltraScan CD inspection report, pipe inspection reports, field NDE results, PII report of the anomaly, any repairs made, etc.

Response:

The information herein contains documentation relating to the Clearbrook to Superior inspection digs that were completed as a result of the PII UltraScan CD tool run of 2002. This documentation includes a summary spreadsheet of the excavations completed (Tab 18.2), the UltraScan CD Inspection report (Tab 18.3), the Enbridge "Defect Selection Criteria" matrix that correlates the in-line inspection indication types with the expected defect types (Tab 18.4), a copy of the April 25, 2003 presentation to the OPS (Tab 18.5), and a CD with the field inspection reports (Tab 18.6).

The enclosed summary spreadsheet ("Tab 18.2 - Table 18.2: 2002 – 2003 Crack Excavation Program Line 3 Clearbrook to Superior") describes the locations where field investigations were conducted as well as the associated in-line inspection and field NDE results. The table has been updated to include field results on 4 digs that were not available at the time of the April 22 presentation to the OPS bringing the total number of joints inspected between Clearbrook and Superior to 121. Within the 121 joints assessed, the UltraScan CD tool reported approximately 285 individual indications.

As part of the standard Enbridge process for conducting field investigations, the pipe was NDE inspected upstream and downstream from the in-line inspection identified feature. At several locations, additional anomalies were identified by field NDE that were minor and below the threshold reporting requirements of the PII UltraScan CD tool. Enbridge continues to make improvements to the field NDE process for sizing and describing signals. Significant improvements have been achieved in recent years regarding feature sizing techniques and further work is underway regarding the nomenclature used to describe feature types as seen in the field. The descriptors used within Table 18.2 for describing the field NDE observations are still under review. Until refinements can be developed, repair decisions have considered worst case scenarios and, in some instances, it is likely that innocuous features have been repaired as shown in Table 18.2.

The bullet points below summarize the results of the excavation program:

- Field NDT identifies many small features that are found in the field as "cracks". Enbridge experience is that these indications may be cracks, lack of fusion, hook defects, inclusions or other manufacturing defects. For reporting purposes, Enbridge identifies these features as "linear indications". For repair and statistical purposes, Enbridge treats all "linear indications" as crack indications.

- 15 excavations have been conducted on sites with suspected "Toe Crack" defects (as per the "Defect Selection Criteria" matrix in Tab 18.4). Of the 8 US Steel sites with possible toe cracking, 3 sites had external linear indications that Enbridge strongly suspects are cracking at the toe of the weld. The remaining sites contained 3 SCC indications, 1 gouge and 1 weld profile features. Of the 7 Kaiser sites with possible toe cracking, 1 site had an external linear indication at the toe of the weld that Enbridge strongly suspects is toe cracking, 3 sites had lack of fusion and 3 sites had a raised or sharp weld profile.
- 21 additional external toe cracks were also found on US Steel as a result of the field investigations. No additional features were found on Kaiser pipe. The UltraScan CD tool did not identify these defects since they were below threshold limits. Two of the features (MP 1003.0578 and MP 1011.4924) had an NDT reported length that placed it above the threshold limits, however, the NDT report indicates that the long seam feature at these locations are "intermittent". It is likely that the continuous crack lengths within this feature are below the threshold size of the UltraScan CD tool. As a result, Enbridge believes that there were no "Toe Crack" features found in the field that exceeded tool thresholds and were not identified by the tool.
- Of the 285 indications reported by the UltraScan CD tool and assessed during the excavation program, approximately 60 indications had field verified features with dimensions for depth, length or both that were below the contracted tool threshold of 1mm deep (approximately 14% through wall) or 60 mm long (approximately 2.4 inches long). This demonstrates that the UltraScan CD tool is finding features that are below the contracted threshold limits.
- Of the 285 indications noted above, all but two of the UltraScan CD reported indications had a corresponding field verified feature associated with the indication. One of the two indications (MP 1019.8175) was an in-weld (iw), notch-like (nl) indication on AO Smith flash welded pipe. While the NDT report indicated there was no feature at this location, the indication may be due to a proud weld that was not identified through field NDT. The other indication (MP 1090.9008) was a base metal (bm), external metal loss (ml) indication that may have been associated with a minor wall loss that was not detected by the NDT technician.
- The Line 3 "Toe Crack" depth and length plots are contained within the presentation to the OPS in Tab 18.5. These plots show that the depth and length correlation of the field vs. the tool results are very good and are consistent with other investigations completed on the Enbridge system between Edmonton and Clearbrook.
- Approximately 71 joints were excavated in the Clearbrook to Superior Section of line to assess Stress Corrosion Cracking (SCC) indications. The UltraScan CD tool was very successful at identifying locations where relevant SCC features were present on the

line. The SCC Dig Results (Length and Depth Comparison) contained in the OPS presentation in Tab 18.5 for field vs. tool results showed that the tool is undersizing SCC features. This can be attributed to the way in which field data is gathered for SCC features. Typically low level SCC (below tool thresholds) is present between SCC features. Field NDT personnel will group these SCC features together and report the entire length of the SCC clusters. Depth data is undersized due to the complexity of the reflectors within the SCC field. The tool has however demonstrated its ability to find and discriminate relevant SCC features. Enbridge is currently working with PII to recalibrate the tool data to enable better depth estimates for SCC features.

- Long seam indications associated with AO Smith flash welded pipe are typically associated with manufacturing hook defects (see Tab 18.4 for the "Defect Selection Criteria" matrix). Currently PII does not provide depth estimation for notch-like features. Enbridge has requested depth estimates for all remaining notch-like features to determine whether other notch-like features should be excavated. For repair purposes, any linear indications verified through field assessment are treated as crack defects.

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'03 -4

April 3, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

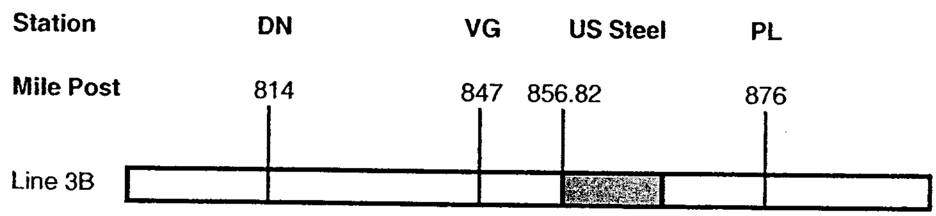
CPF No. 3-2002-5017H
Modification of Return-to-Service Plan

Enbridge is requesting a modification to its Return-to-Service Plan associated with the 34" US Steel pipe. Since December 2002, Line 3B has been operating with a restricted maximum allowable discharge pressure at Donaldson Station (MP 814) of 494 psig. Viking station (MP 847), which had been removed from Line 3B service prior to the Cohasset incident, is now required to be reactivated as a result of the completion of the Terrace Phase III project. The US Steel pipe downstream of both Donaldson and Viking, begins at approximately MP 856.82.

To maintain the pressure limitation currently imposed on this section of US Steel pipe, Enbridge proposes to operate Viking station with a maximum allowable discharge pressure of 330psig. This discharge pressure would ensure that the US Steel pipe downstream of Viking would not experience pressures greater than 310 psig in flowing or shutdown operations, for all crude types in the line. Under the current restrictions without Viking station on line, pressures in excess of 310 psig have been experienced on this section of US Steel pipe. In addition, 310 psig is approximately 50% of the AWP for this section of US Steel pipe. Although the maximum pressures seen on this segment would not change as a result of reactivating Viking, the overall average pressure profile would increase slightly.

With the addition of Viking station, there would be no US Steel pipe in the Line 3B segment from Donaldson to Viking. As a result, Enbridge also proposes to return the Donaldson maximum allowable discharge pressure to the pre-incident level of 618 psig.

Your prompt approval for this modification to our Return-to-Service Plan would be appreciated.



Sincerely,

J. R. Sobojinski

c: Dan Tutcher
Greg Sevick
John Hayes
Law

36

Compl Reg
Dave
Phil

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ENBRIDGE™

'03 -4

March 25, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

30

Enbridge Pipelines (Lakehead) L.L.C.
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ENBRIDGE™

February 18, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J.R. Sobojinski / jef

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

28

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ENBRIDGE™

February 4, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

(26)

Comp'd Req. Ivan distributed

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ENBRIDGE™

January 29, 2003

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

On July 8, 2002 Enbridge submitted to the OPS its return-to-service plan as directed by the Corrective Action Order issued on July 5, 2002. Since that time, in the full spirit of cooperation, Enbridge has provided your office with a significant amount additional information which clarifies and further details our return-to-service plan. We have also sponsored two separate face-to-face meetings in Kansas City to present specifics related to our integrity management program and the processes and tools used to identify and mitigate crack like defects within our system.

Your letter dated December 31, 2002 has requested additional specific information in order to further review and evaluate our proposed return-to-service plan. Each of the issues raised in your letter has been comprehensively addressed, with the exception of your item No. 3. The PII UltraScan CD report for the 34-inch Clearbrook to Superior line section has not been completed. PII has provided Enbridge preliminary data and Enbridge has begun field investigation activities based on this preliminary information. Once completed by PII, the inspection final report will be forwarded to accommodate this request. All other supporting information has been included in the attached package.

Upon completion of your review of this information, we again respectfully request the removal of the existing pressure restrictions on the 34" US Steel pipe upstream of Clearbrook Station, to the Canadian border. We are confident that we have demonstrated that all reasonable measures have been taken to safely return this portion of our system to full service.

In addition, we also reiterate our request for approval of our "34-inch Return-to-Service Plan" as previously submitted. This plan details the mitigative actions which have already been taken, as well as future measures which will ensure the integrity of all 34" US Steel pipe in our system. Enbridge continues to be a safe and responsible operator and is dedicated to ensuring the continued safety of both the public and the environment.

If you should have any questions or concerns regarding any of the information submitted, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes
Joel Kanvik
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

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December 31, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart is the same as last week's.

If you have any questions regarding the information provided, or on any other matters, please contact me at 218 / 725 - 0505.

Sincerely,

John R Sobojinski

John R. Sobojinski

c: David Bryson
John Hayes

Attachment

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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December 24, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart is the same as last week's.

If you have any questions regarding the information provided, or on any other matters, please contact me at 218 / 725 - 0505.

Sincerely,

J. R. Sobojinski / jf

John R. Sobojinski

c: David Bryson
John Hayes

Attachment

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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19

ENBRIDGE™

December 17, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart is the same as last week's.

If you have any questions regarding the information provided, or on any other matters, please contact me at 218 / 725 - 0505.

Sincerely,

John R Sobojinski

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

Compl Reg MnOps
Dave
Phil

(17)

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ENBRIDGE™

December 11, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office a weekly tabulation of the occurrences in which the agreed upon maximum operating pressures were exceeded.

If you have any questions regarding the information provided or on any other matters please contact me at 218 / 725 - 0505.

Sincerely,

John R. Sobojinski

Attachment
c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

(56)

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ENBRIDGE™

July 15, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables these past two weeks; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski / jef
John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 seconds	Pressure backed up when a Floodwood unit was stopped due to a power consumption.
05/19/03	PL	466 psig	5.42%	53 seconds	Sediment plugged the Clearbrook transmitter line causing a faulty reading.

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

55

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ENBRIDGE™

July 2, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J.R. Sobojinski /jof

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

(54)

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ENBRIDGE™

June 24, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

74

Comp'l Reg
Ivan
Stewart
Dave

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ENBRIDGE™

November 6, 2003

NEXT DAY MAIL

Mr. Ivan Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2002-5017H

Dear Mr. Huntoon:

Further to our October 16 letter and my recent conversation with Dave Barrett, I would like to reaffirm Enbridge's position that all required work has been completed for the above-referenced subject, and we look forward to final OPS approval of pressure restoration for the 34-inch pipeline. In addition, we remain on schedule for providing you the three additional miscellaneous items by the end of the year, as requested in your September 5 letter.

In our October 16 letter, we confirmed that all required repairs have been completed. Given the detailed analysis and overall scrutiny of our 34-inch line, we felt it appropriate to inform you of a minor dent at MP 1072. This is located approximately 29 miles downstream of Floodwood, is subject to relatively low mainline pressures, and is scheduled for field investigation by the end of 2003. We are treating this dent in accordance with our standard methods, as detailed in our Operating & Maintenance Procedures manuals. This anomalous dent feature is not related to cracking or stress corrosion cracking. Enbridge has been aware of this anomaly, and appropriately scheduled field investigation for winter when the marshy area will be frozen, in order to better facilitate the work. We do not view this repair as part of the 34" dig program; therefore, it should not be considered as one of the requirements for removing the 34" pressure restrictions.

While the above issue is noteworthy since it involves the 34-inch line, we are notifying you in order to avoid any confusion with or connection to the process in place, ultimately geared toward pressure restoration on our 34-inch line. We appreciate OPS efforts to date toward understanding the Enbridge pipeline system and its related programs. Enbridge strives to maintain open communication with the OPS and will continue to proactively address items of potential concern.

Should you have any questions or would like to discuss any of the above information in further detail, please contact me.

Sincerely,

John R Sobojinski
pb

John R. Sobojinski

c: Dave Barrett
John Hayes
Walter Kresic
Art Meyer
Mark Sitek
Mark Willoughby

72

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mark.willoughby@enbridge.com

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October 28, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were two pressure excursions over allowables this past week, the attached chart reflects those changes.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 sec	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 sec	Pressure backed up when a Floodwood unit was stopped due to a power consumption.
05/19/03	PL	466 psig	5.42%	53 sec	Sediment plugged the Clearbrook transmitter line causing a faulty reading.
09/04/03	GF	448 psi	2.50%	20 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection.
09/04/03	VK	349 psi	5.70%	53 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection. Pressures fluctuated +/- 5psi of MAOP for approximately 20 minutes after the shutdown
09/11/03	VK	349 psi	5.70%	20 sec	Slow acting PCV at Viking Station
09/14/03	MP 1002	435 psi	3.50%	30 sec	Faulty pressure transmitter. We do not believe pressures actually exceeded allowable.
10/03/03	VK	352 psi	6.70%	40 sec	Line shutdown Cromer to Clearbrook for a CR fullstream injection. Settling of line pressures after the shutdown.
10/11/03	GF	455 psi	4.10%	20 sec	Line startup from Cromer to Superior. Pressure exceeded for 1 scan as units were being brought on.
10/12/03	VK	342 psi	3.60%	10 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 10 secs at Viking during the swing.
10/13/03	VK	345 psi	4.50%	40 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 40 secs at Viking during the swing.
10/16/03	VK	339 psi	2.70%	45 sec	Pressure spike at Viking during a non-routine change in line rate. Pressure peaked at 339 psi.
10/20/03	VK	360 psi	9.00%	20 sec	Line startup from Cromer to Superior. Pressure spike as units were brought on line.
10/22/03	VK	350 psi	6.00%	40 sec	During a L3 startup following a L3 Clearbrook injection the discharge pressure at Viking spiked for approx 40 sec when unit 2 failed to start.
10/26/03	VK	341 psi	3.30%	20 sec	L3 startup Cromer to Superior. Pressure over shot discharge setpoint momentarily while bringing units on.
10/26/03	GF	445 psi	1.80%	15 sec	L3 startup Cromer to Superior. Operator dropped a Gretna unit in reaction to pressures at Viking exceeding setpoint causing momentary pressure spike at Gretna

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

50

Dave
Phil

Enbridge Pipelines (Lakehead) L.L.C.
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ENBRIDGE™

June 10, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski / jf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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RECEIVED AUG 2 6 2005

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PHMSA-CENTRAL REGION-OPS
901 LOCUST STREET, RM 462
KANSAS CITY, MO 64106
PHONE: 816-329-3800
FAX: 816-329-3831

August 24, 2005

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

Attached are two copies of the Kiefner & Associates report entitled "Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-inch Line 3 – Quarter 4 of 2004", as requested in your December 9, 2003 letter to Enbridge.

No field activities were undertaken (i.e., excavations or inline inspection) during the fourth quarter of 2004.

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J. Willoughby

Attachments

c/att: Brian Pierzina
Joy Kadnar
Michael McGrath

PIPELINE INTEGRITY

AUG 17 2004

Kiefner & Associates, Inc.

August 11, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3 Quarter 4 of 2004

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI Report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the fourth quarter of 2004.

The current analysis process was identical to that used for the previous analyses, the first quarter of 2004 (KAI Report 0023-0404), the second quarter of 2004 letter report and the June 2003 fatigue analysis (KAI Report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that there has not been a substantial change in operation during 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 87.2 years was calculated using the 2004 Quarter 4 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by approximately 74 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 44 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

M.J. Rosenfeld/gw

Michael J. Rosenfeld
President
Senior Structural Engineer

CEK/MJR:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Clearbrook 2004 Q3	***19.6***	***18.1***	***17.1***	***17.1***	***17.1***	***20.1***	***30.7***	***55.9***	***117.9***
	Clearbrook 2004 Q4	***20.7***	***19.1***	***18.1***	***17.6***	***18.1***	***21.7***	***32.3***	***60.0***	***126.0***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Deer River 2004 Q3	***10.1***	***9.6***	***9.1***	***8.6***	***9.3***	***12.6***	***21.9***	***44.1***	***96.8***
	Deer River 2004 Q4	***11.6***	***10.6***	***10.1***	***9.6***	***10.6***	***14.1***	***24.7***	***49.9***	***108.9***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Cass Lake 2004 Q4	***12.6***	***11.6***	***11.6***	***11.1***	***11.6***	***13.6***	***19.6***	***34.3***	***72.1***
	Cass Lake 2004 Q3	***13.8***	***12.6***	***12.2***	***12.2***	***12.6***	***14.6***	***20.7***	***35.9***	***75.3***
	Floodwood 2004 Q2	***17.2***	***16.1***	***15.6***	***15.4***	***15.7***	***18.3***	***26.2***	***47.0***	***99.1***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q3	***24.0***	***22.2***	***21.7***	***21.5***	***22.0***	***25.5***	***36.6***	***65.9***	***138.4***
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***
	Floodwood 2004 Q4	***28.2***	***26.2***	***25.6***	***25.2***	***25.7***	***30.1***	***43.4***	***78.0***	***164.3***

* Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2004 Quarter 4 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 4 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2104	161.4	130.3	191.0	204.6	19.4
MP 912.9	Transition to 0.344-inch WT	2094	145.1	117.2	171.8	184.0	23.2
MP 917.5	Transition to 0.312-inch WT	2095	146.4	118.2	173.3	185.5	32.4
MP 925.8	Transition to 0.281-inch WT	2125	194.3	157.2	230.3	246.5	61.3
Cass Lake	Cass Lake discharge pressures	2046	77.3	63.6	89.7	87.2	13.2
Deer River	Deer River discharge pressures	2085	145.6	113.1	148.2	166.9	21.3
MP 999.9	Transition to 0.312-inch WT	2076	128.8	100.0	131.1	147.7	26.3
MP 1007.2	Transition to 0.281-inch WT	2082	138.6	107.8	141.4	159.3	40.5
Floodwood	Floodwood discharge pressures	2100	165.5	117.8	165.2	195.6	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

Enbridge Pipelines (Lakehead) L.L.C.
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Mark J. Willoughby, Manager
Compliance
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mark.willoughby@enbridge.com

ENBRIDGE™

July 27, 2004

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

As discussed in our meeting with you on July 8, 2004, we are providing two copies of the presentation given by Enbridge on CD along with two copies of the Kiefner & Associates report entitled "Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-inch Line 3 – Quarter 1 of 2004."

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J. Willoughby

Mark J. Willoughby

Attachments

c: Brian Pierzina w/attachments
Joy Kadnar "
Ron Wiest "

04-42

QUARTERLY ANALYSIS TO ASSESS THE EFFECTS OF PRESSURE CYCLES ON ENBRIDGE'S 34-INCH LINE 3—QUARTER 1 OF 2004

Kiefner & Associates, Inc.

585 Scherers Court
Worthington, Ohio 43085
(614) 888-8220

Final Report No. 04-42

FINAL REPORT

on

QUARTERLY ANALYSIS TO ASSESS THE EFFECTS OF PRESSURE CYCLES ON ENBRIDGE'S 34-INCH LINE 3—QUARTER 1 OF 2004

to

ENBRIDGE PIPELINES, INC.

July 2, 2004

by

Carolyn E. Kolovich

KIEFNER AND ASSOCIATES, INC.
585 Scherers Court
Worthington, Ohio 43085

0023-0404

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QUARTERLY ANALYSIS TO ASSESS THE EFFECTS OF PRESSURE CYCLES ON ENBRIDGE'S 34-INCH LINE 3 – QUARTER 1 OF 2004

by

Carolyn E. Kolovich

INTRODUCTION

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the 2004 first quarter pressure cycles were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (Kiefner and Associates, Inc. [KAI] Final Report 03-29 on Project 0023-0205) is adequately conservative relative to the actual operating conditions. The quarterly pressure cycles were analyzed to determine their effects on hypothetical defects that may remain in the pipeline. The focus of the analysis is on the portions of the pipeline located downstream from the Clearbrook, Cass Lake, Deer River, and Floodwood Stations.

The analysis presented herein covers three aspects of the effects of the pressure cycles. These three areas are as follows:

- Comparison of operational pressure cycles from January 2004 through March 2004 to pressure cycles used in the June 2003 fatigue analysis (representative of operations leading up to the Cohasset failure)
- Comparison of operational pressure cycles from January 2004 through March 2004 to our benchmark cycles to determine the relative aggressiveness
- Prediction of a time to failure based on the operational cycles from January 2004 through March 2004 and the flaw sizes and fatigue constants used in the June 2003 analysis.

SUMMARY

Comparison of the operational pressure cycles from January 2004 through March 2004 to the compilation of pressure cycles we have obtained for the Clearbrook, Cass Lake, Deer River, and Floodwood discharges shows that the current operations are less intensive and, therefore, less likely to cause rapid crack growth than the historical cycles. Furthermore, the comparison has shown that the pressure-cycle data used in the June 2003 fatigue analysis is conservative

when compared to current operation at Clearbrook, Cass Lake, Deer River, and Floodwood pump stations.

Comparison of the operational pressure cycles from January 2004 through March 2004 to our benchmark cycles shows that Line 3 operates under conditions considered to be moderately aggressive to aggressive at Deer River discharge, light to moderate at Clearbrook and Cass Lake discharges, and light at the Floodwood discharge.

Using a potential remaining flaw size determined by the threshold ability of the Ultrascan CD in-line-inspection tool, 0.40 inch deep by 2.36 inches long (1 mm deep by 60 mm long), it was determined that the shortest time to failure for this defect is predicted to be in 77.3 years at Cass Lake discharge. The June 2003 fatigue analysis predicted this same flaw would fail after 13.12 years. The predicted time is shorter for Cass Lake than for Deer River (more aggressive cycles) because the pipe in the Cass Lake discharge is a thinner wall thickness than that in the Deer River Discharge.

ANALYSIS

Comparison of Current Cycles to Pressure Cycles Leading up to the Cohasset Failure

Pressure-cycle histograms were created for the Clearbrook, Cass Lake, Deer River, and Floodwood discharges using the pressure data from January 2004 through March 2004. The histograms, shown in Figures 1 through 4 and tabulated in Table 1, look at the number of occurrences of pressure cycles based on the change in pressure of each pressure cycle in 50 psi increments. Also shown in the figures and table are pressure-cycle data from January 2000 through March 2000, data representative of operations leading up to the Cohasset failure.

Table 1. Comparison of 2004 Quarter 1 Pressure Cycles to 2000 Quarter 4 Pressure Cycles

Change in Pressure for Each Pressure Cycle, psi	Clearbrook 2004 Quarter 1	Clearbrook 2000 Quarter 1	Cass Lake 2004 Quarter 1	Cass Lake 2000 Quarter 1	Deer River 2004 Quarter 1	Deer River 2000 Quarter 1	Floodwood 2004 Quarter 1	Floodwood 2000 Quarter 1
751-800	0	8	0	0	0	0	0	0
701-750	0	37	0	0	0	0	0	0
651-700	0	36.5	0	0	0	2	0	0
601-650	0	16	0	1	0	24.5	0	0
551-600	1	11	0.5	25	0	48	0	16
501-550	3	16	0	58.5	1	21	0	42.5
451-500	7.5	11	3.5	15	6.5	18	0	25
401-450	7.5	4	9	16	11.5	9	0	24
351-400	9	3	9.5	17	10.5	16	0.5	22
301-350	7.5	8	9	8	6.5	10	12	13
251-300	9.5	9	8.5	12	4	12	8	16
201-250	7	28	9	20	7	27.5	13	24
151-200	30.5	39	22	43	8	43	12.5	48
101-150	44	89	44	88	50	118	38	92.5
51-100	150.5	292.5	121	388	101.5	325	96.5	276.5

The above table and accompanying figures show that there has been a significant reduction in the number of large pressure cycles occurring at each location, particularly at the Clearbrook discharge. Operational changes associated with Enbridge's capacity expansion were effective mid 2002. The above analysis shows that current operations have eliminated any pressure cycle with a change in pressure greater than 600 psi at all four locations. A significant reduction has also occurred in the cycles with a change in pressure of 500 to 600 psi. As the largest cycles obviously have the greatest impact on the rate of crack growth, it can be said that current operations are expected to cause less rapid crack growth.

Comparison of Current Cycles to Benchmark Pressure Cycles to Determine Relative Aggressiveness

To determine the relative aggressiveness of the pressure cycles, the pressure data for the pipeline at the each discharge were compared to our benchmark cycles through our model that determines a predicted time to failure. The benchmark cycles are depicted in Table 2 for the X52 0.375 WT (Clearbrook discharge), 0.344 WT (Deer River discharge) and 0.281 WT (Cass Lake and Floodwood discharges) line pipe and include the actual cycles at each discharge used for the analysis. Detailed results of the failure model can be found in Appendix A. These benchmark cycles are based on actual pressure patterns observed for pipelines in which fatigue failures have occurred.

The following parameters are held constant for the aggressiveness analysis.

- Diameter: 34 inches
- Material toughness of 40 ft-lb
- Crack-growth-rate constants: C = 9.82E-16 (for ΔK in psi$\sqrt{in}$), n=2.363

At each location, the test pressure from the 1992 hydrostatic test was used to determine a range of sizes of defects (depth/length combinations) that may have survived the hydrostatic test. Table 2 summarizes the time to failure for each of these defects. Note that these times to failure are not the real times to failure, rather they serve as a means to assess the relative aggressiveness of the cycles compared to our benchmark cycles. Table 2 should be used to assess the nature of the cyclic behavior, not to predict a reassessment interval.

The results (in terms of relative times to failure in years) show that the January 2004 through March 2004 pressure cycles are moderately aggressive to aggressive at Deer River discharge, light to moderate at Clearbrook and Cass Lake discharges, and light at the Floodwood discharge.

For comparison with the June 2003 fatigue analysis, Table 2 also includes the time to failure as determined using the 2000 first quarter pressure data. The change in operations from 2000 to 2004 has lessened the aggressiveness at all four analysis locations significantly. All the 2000 pressure data is considered aggressive to very aggressive when compared with our benchmark cycles. The current operational data has reduced the classifications to moderately aggressive to aggressive at Deer River and all the way to light operations at Floodwood.

Table 2. Comparison of Times to Failure for Actual Cycles and Benchmark Cycles

		Initial Crack Depth with Length Determined by Hydrostatic Test Pressure								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Initial Crack Depth with Length Determined by Hydrostatic Test Pressure								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Initial Crack Depth with Length Determined by Hydrostatic Test Pressure								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***

Prediction of a Time to Failure Based on a Set Flaw Size

The final portion of the analysis predicts a time to failure based on the January 2004 through March 2004 pressure data and the existence of a flaw size determined by the threshold ability of the Ultrascan CD in-line-inspection tool. A flaw with a 0.04-inch depth and a length of 2.36 inches is assumed to exist anywhere in the line. Therefore, nine cases were examined to determine the location at which the flaw would be expected to grow to failure in the shortest time. Each discharge was examined, in addition to the locations downstream of Clearbrook and Deer River where a transition to thinner wall pipe occurs. A scale factor was applied to the discharge pressures to determine the pressures at the locations of the transitions. Table 3 shows the times to failures, in years, at each of the nine locations examined. For comparison with the June 2003 fatigue analysis, Table 3 also includes the time to failure as determined using the 2000 first quarter pressure data.

Table 3. Time to Failure of Defect Determined by the Threshold Ability of the Ultrascan CD In-Line-Inspection Tool

Location	Comment	Scale Factor	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	1	161.4	19.4
MP 912.9	Transition to 0.344-inch WT	0.93	145.1	23.2
MP 917.5	Transition to 0.312-inch WT	0.81	146.4	32.4
MP 925.8	Transition to 0.281-inch WT	0.62	194.3	61.3
Cass Lake	Cass Lake discharge pressures	1	77.3	13.2
Deer River	Deer River discharge pressures	1	145.6	21.3
MP 999.9	Transition to 0.312-inch WT	0.92	128.8	26.3
MP 1007.2	Transition to 0.281-inch WT	0.77	138.6	40.5
Floodwood	Floodwood discharge pressures	1	165.5	14.3

The shortest time to failure of 77.3 years is at Cass Lake Discharge. Although it appears from the histograms in Table 1 that more aggressive cycles are occurring at the discharge of Clearbrook and Deer River, these locations have heavier wall pipe, 0.375 inch and 0.344 inch, respectively, resulting in a longer time to failure of the 0.04-inch by 2.36-inch flaw. The wall thickness at the discharge of Cass Lake is the thinnest in the entire portion of the line examined and it would be expected that the effects of the pressure cycles at the discharge would be the greatest.

A previous analysis conducted in June of 2003 determined that the time to failure of a 0.04-inch by 2.36-inch-long defect was 21.3 years at the Deer River discharge, using the pressure data from 2000. The above results show that at this location, using the pressure data from January 2004 through March 2004, the time to failure has increased to 145.6 years. As all other parameters in the analysis were held constant, the increase in life is a direct result of the elimination of large and frequent pressure cycles.

CONCLUSIONS

The efforts made by Enbridge to reduce the pressure cycles in the 34-inch Line 3 have resulted in an increase in the predicted time to failure of defects that may remain in the pipeline. The shortest time to failure arising from the January 2004 through March 2004 pressure data is 77.3 years. In accordance with the commitment from Enbridge, this analysis will be completed again following the second quarter of 2004. Quarterly analyses will be performed to determine if the cyclic behavior changes from that seen in this analysis.

Figure 1. Clearbrook Pressure Cycles

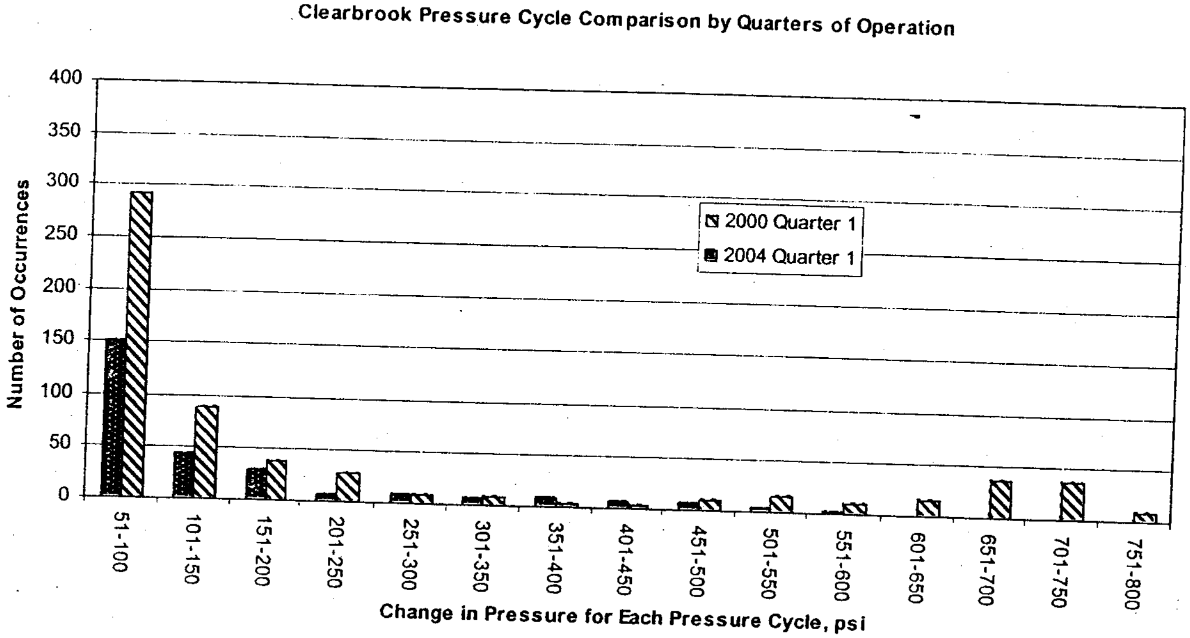


Figure 2. Cass Lake Pressure Cycles

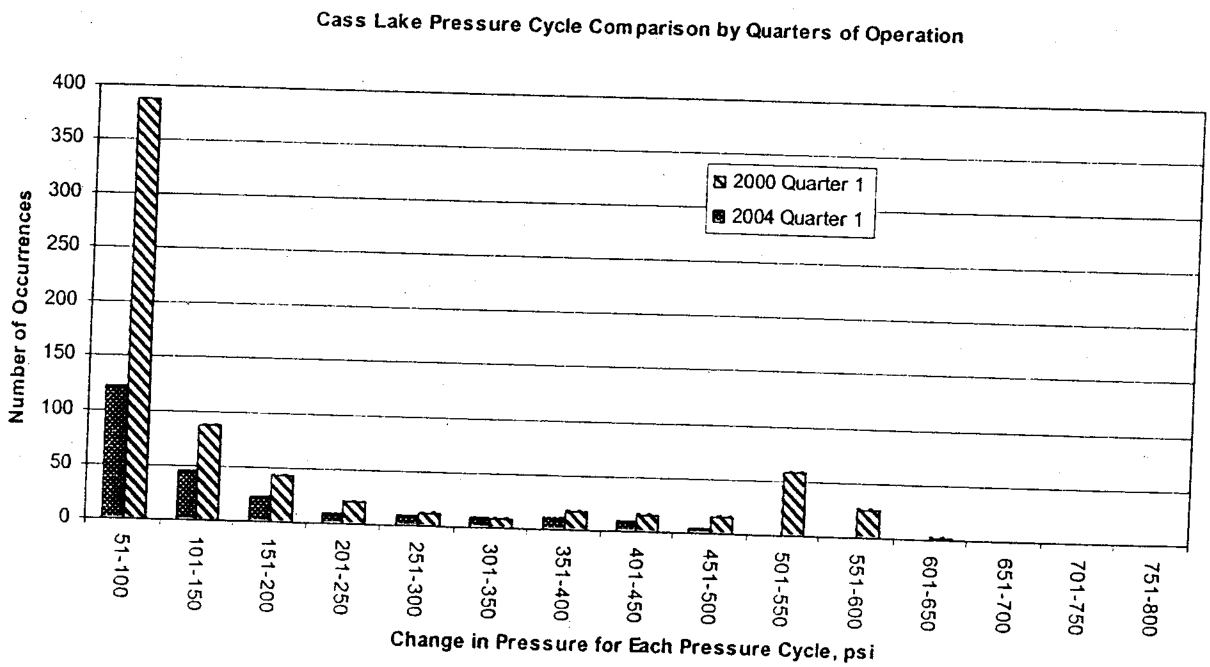


Figure 3. Deer River Pressure Cycles

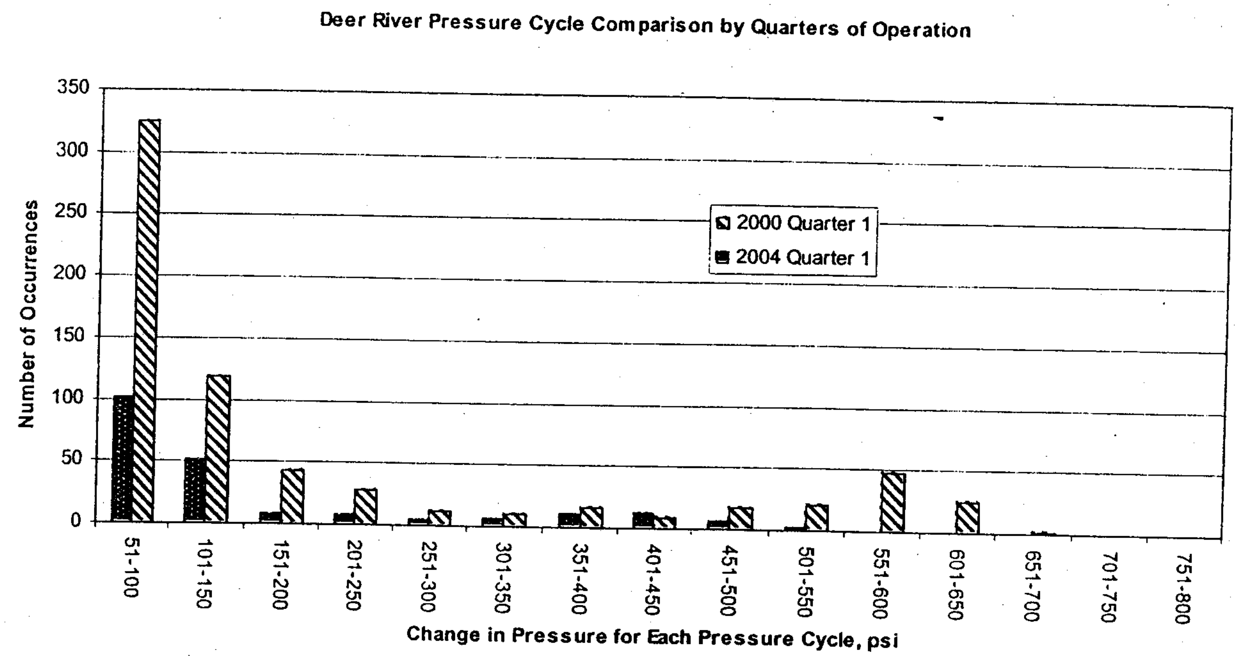
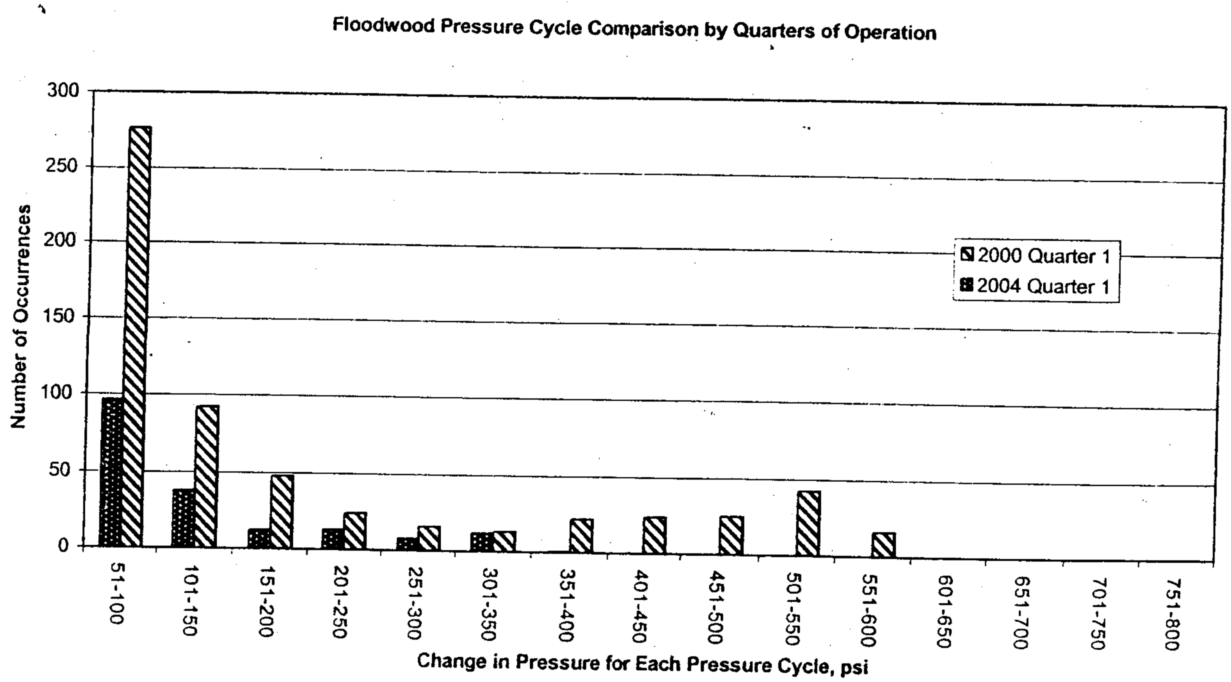


Figure 4. Floodwood Pressure Cycles



APPENDIX A

PIPELIFE Results

```
TODAY'S DATE IS 05-24-2004  THE TIME IS 15:32:01  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CR-VA375.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Very Aggressive Benchmark .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000  12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.375 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=826 psi
  2.  HYDROSTATIC TEST PRESSURE=1147 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1

SECTION 6.  PRESSURE HISTORY
                  -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=44

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1147   NO. OF PRESSURE HISTORIES=  44
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  826  PMin =  539  N =    250
   2  PMax =  826  PMin =  425  N =    125
   3  PMax =  826  PMin =  310  N =     62
   4  PMax =  826  PMin =  195  N =     12
  41  PMax =  826  PMin =  195  N =     13
  42  PMax =  826  PMin =  310  N =     63
  43  PMax =  826  PMin =  425  N =    125
  44  PMax =  826  PMin =  539  N =    250

Cycle Spectrum  PMax =  826  PMin =     0
       No. Of Days in the    44 Pressure Pair(s) =     365
No. of Cycles (N's) in the   44 Pressure Pair(s) =    3,660
                              Conversion Factor =    3,660.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.605	4575	1.25	0.961	0.3602	0.6814	825	826
0.800	0.3000	0.925	4097	1.12	0.925	0.3468	0.9924	816	826
0.700	0.2625	1.245	3910	1.07	0.885	0.3319	1.2978	813	826
0.600	0.2250	1.615	3660	1.00	0.832	0.3121	1.6521	824	826
0.500	0.1875	2.100	3890	1.06	0.770	0.2888	2.1240	826	826
0.400	0.1500	2.805	4200	1.15	0.697	0.2614	2.8191	823	826
0.300	0.1125	3.960	5948	1.63	0.607	0.2275	3.9669	825	826
0.200	0.0750	5.770	10362	2.83	0.514	0.1927	5.7732	825	826
0.100	0.0375	8.150	21295	5.82	0.429	0.1607	8.1516	824	826

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:10  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CR-A375.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Aggressive Benchmark .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.375 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=826 psi
  2.  HYDROSTATIC TEST PRESSURE=1147 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1

SECTION 6.  PRESSURE HISTORY
               -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=44

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  1147   NO. OF PRESSURE HISTORIES=  44
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  826  PMin =  539  N =    62
   2  PMax =  826  PMin =  425  N =    31
   3  PMax =  826  PMin =  310  N =    15
   4  PMax =  826  PMin =  195  N =     3
  41  PMax =  826  PMin =  195  N =     3
  42  PMax =  826  PMin =  310  N =    16
  43  PMax =  826  PMin =  425  N =    32
  44  PMax =  826  PMin =  539  N =    63

Cycle Spectrum  PMax =  826  PMin =    0
        No. Of Days in the    44 Pressure Pair(s) =      365
No. of Cycles (N's) in the    44 Pressure Pair(s) =      912
                               Conversion Factor =      912.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.605	4560	5.00	0.961	0.3603	0.6810	823	826
0.800	0.3000	0.925	3983	4.37	0.924	0.3464	0.9909	822	826
0.700	0.2625	1.245	3756	4.12	0.881	0.3305	1.2960	826	826
0.600	0.2250	1.615	3741	4.10	0.832	0.3119	1.6518	825	826
0.500	0.1875	2.100	3812	4.18	0.772	0.2897	2.1243	821	826
0.400	0.1500	2.805	4393	4.82	0.698	0.2619	2.8192	821	826
0.300	0.1125	3.960	6033	6.62	0.607	0.2276	3.9669	825	826
0.200	0.0750	5.770	10365	11.37	0.514	0.1927	5.7732	825	826
0.100	0.0375	8.150	21367	23.43	0.429	0.1607	8.1515	824	826

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:11  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CR-M375.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Moderate Benchmark .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000    12:29:00
SECTION 2.  GEOMETRY ID               SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=826 psi
  2.  WALL THICKNESS=0.375 in.          2.  HYDROSTATIC TEST PRESSURE=1147 psi
SECTION 3.  MATERIAL ID               SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs         SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=34
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1147   NO. OF PRESSURE HISTORIES=  34

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  826  PMin =  539  N =     25
   2  PMax =  826  PMin =  425  N =     12
   3  PMax =  826  PMin =  310  N =      6
   4  PMax =  826  PMin =  195  N =      1
  31  PMax =  826  PMin =  195  N =      1
  32  PMax =  826  PMin =  310  N =      6
  33  PMax =  826  PMin =  425  N =     12
  34  PMax =  826  PMin =  539  N =     25

Cycle Spectrum  PMax =  826  PMin =     0

       No. Of Days in the    34 Pressure Pair(s) =      365
No. of Cycles (N's) in the    34 Pressure Pair(s) =      363
                               Conversion Factor =      363.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.605	4592	12.65	0.961	0.3602	0.6804	826	826
0.800	0.3000	0.925	4018	11.07	0.923	0.3462	0.9904	826	826
0.700	0.2625	1.245	3786	10.43	0.881	0.3305	1.2959	826	826
0.600	0.2250	1.615	3763	10.37	0.832	0.3120	1.6518	825	826
0.500	0.1875	2.100	3859	10.63	0.771	0.2891	2.1240	824	826
0.400	0.1500	2.805	4408	12.14	0.696	0.2608	2.8189	826	826
0.300	0.1125	3.960	6119	16.86	0.608	0.2278	3.9670	824	826
0.200	0.0750	5.770	10502	28.93	0.514	0.1928	5.7732	825	826
0.100	0.0375	8.150	21728	59.86	0.427	0.1601	8.1514	826	826

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:11  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CR-L375.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Light Benchmark .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.375 in.
SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000
SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=826 psi
  2.  HYDROSTATIC TEST PRESSURE=1147 psi
SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1
SECTION 6.  PRESSURE HISTORY
              -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=20
SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in     WALL THICKNESS=  .375 in
FLOW STRESS   =  62000
CVN           =  40
C =  9.82D-16       n =  2.263
HTP=  1147   NO. OF PRESSURE HISTORIES=  20

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
  1  PMax =  826  PMin =  539  N =    12
  2  PMax =  826  PMin =  425  N =     6
  3  PMax =  826  PMin =  310  N =     6
  4  PMax =  826  PMin =  425  N =     6
 17  PMax =  826  PMin =  425  N =     6
 18  PMax =  826  PMin =  310  N =     7
 19  PMax =  826  PMin =  425  N =     7
 20  PMax =  826  PMin =  539  N =    13

Cycle Spectrum  PMax =  826  PMin =  310

      No. Of Days in the      20 Pressure Pair(s) =      365
No. of Cycles (N's) in the    20 Pressure Pair(s) =      175
                                Conversion Factor =      175.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.605	5062	28.93	0.961	0.3602	0.6806	825	826
0.800	0.3000	0.925	4399	25.14	0.923	0.3462	0.9903	826	826
0.700	0.2625	1.245	4173	23.85	0.881	0.3305	1.2959	825	826
0.600	0.2250	1.615	4124	23.57	0.832	0.3119	1.6517	825	826
0.500	0.1875	2.100	4230	24.17	0.771	0.2890	2.1240	825	826
0.400	0.1500	2.805	4842	27.67	0.696	0.2609	2.8189	825	826
0.300	0.1125	3.960	6693	38.25	0.607	0.2276	3.9669	825	826
0.200	0.0750	5.770	11530	65.89	0.513	0.1926	5.7732	826	826
0.100	0.0375	8.150	23843	136.25	0.427	0.1603	8.1513	826	826

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:12  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CS-VA281.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Very Aggressive Benchmark .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.
SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000
SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=619 psi
  2.  HYDROSTATIC TEST PRESSURE=860 psi
SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1
SECTION 6.  PRESSURE HISTORY
                -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=44
SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  860    NO. OF PRESSURE HISTORIES=  44

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  619  PMin =  404  N =    250
   2  PMax =  619  PMin =  318  N =    125
   3  PMax =  619  PMin =  232  N =     62
   4  PMax =  619  PMin =  146  N =     12
  41  PMax =  619  PMin =  146  N =     13
  42  PMax =  619  PMin =  232  N =     63
  43  PMax =  619  PMin =  318  N =    125
  44  PMax =  619  PMin =  404  N =    250

Cycle Spectrum  PMax =  619  PMin =    0

       No. Of Days in the     44 Pressure Pair(s) =      365
No. of Cycles (N's) in the    44 Pressure Pair(s) =    3,660
                                Conversion Factor =    3,660.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	4035	1.10	0.964	0.2710	0.5751	603	619
0.800	0.2248	0.800	3403	0.93	0.928	0.2607	0.8429	610	619
0.700	0.1967	1.080	3209	0.88	0.883	0.2482	1.1120	618	619
0.600	0.1686	1.395	3222	0.88	0.833	0.2342	1.4183	618	619
0.500	0.1405	1.815	3316	0.91	0.772	0.2170	1.8302	618	619
0.400	0.1124	2.445	4097	1.12	0.698	0.1961	2.4538	615	619
0.300	0.0843	3.545	5887	1.61	0.605	0.1701	3.5492	616	619
0.200	0.0562	5.445	10383	2.84	0.505	0.1420	5.4468	619	619
0.100	0.0281	7.990	21585	5.90	0.420	0.1180	7.9909	618	619

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:12  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CS-A281.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Aggressive Benchmark .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.
SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000
SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=619 psi
  2.  HYDROSTATIC TEST PRESSURE=860 psi
SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1
SECTION 6.  PRESSURE HISTORY
                    -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=44
SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in     WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  860    NO. OF PRESSURE HISTORIES=  44

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
  1  PMax =  619  PMin =  404  N =    62
  2  PMax =  619  PMin =  318  N =    31
  3  PMax =  619  PMin =  232  N =    15
  4  PMax =  619  PMin =  146  N =     3
 41  PMax =  619  PMin =  146  N =     3
 42  PMax =  619  PMin =  232  N =    16
 43  PMax =  619  PMin =  318  N =    32
 44  PMax =  619  PMin =  404  N =    63

Cycle Spectrum  PMax =  619   PMin =     0

        No. Of Days in the      44 Pressure Pair(s) =       365
No. of Cycles (N's) in the      44 Pressure Pair(s) =       912
                                   Conversion Factor =       912.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	3759	4.12	0.963	0.2706	0.5732	616	619
0.800	0.2248	0.800	3419	3.75	0.926	0.2602	0.8418	617	619
0.700	0.1967	1.080	3300	3.62	0.884	0.2483	1.1123	616	619
0.600	0.1686	1.395	3303	3.62	0.835	0.2346	1.4186	616	619
0.500	0.1405	1.815	3512	3.85	0.775	0.2177	1.8305	614	619
0.400	0.1124	2.445	4041	4.43	0.696	0.1957	2.4538	617	619
0.300	0.0843	3.545	5828	6.39	0.604	0.1697	3.5492	617	619
0.200	0.0562	5.445	10367	11.37	0.506	0.1420	5.4468	619	619
0.100	0.0281	7.990	21950	24.07	0.419	0.1178	7.9909	618	619

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:12  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CS-M281.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Moderate Benchmark .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=619 psi
  2.  WALL THICKNESS=0.281 in.          2.  HYDROSTATIC TEST PRESSURE=860 psi
SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in               -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=34
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  860   NO. OF PRESSURE HISTORIES=  34

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  619  PMin =  404  N =     25
   2  PMax =  619  PMin =  318  N =     12
   3  PMax =  619  PMin =  232  N =      6
   4  PMax =  619  PMin =  146  N =      1
  31  PMax =  619  PMin =  146  N =      1
  32  PMax =  619  PMin =  232  N =      6
  33  PMax =  619  PMin =  318  N =     12
  34  PMax =  619  PMin =  404  N =     25

Cycle Spectrum  PMax =  619  PMin =    0

       No. Of Days in the    34 Pressure Pair(s) =     365
No. of Cycles (N's) in the    34 Pressure Pair(s) =     363
                               Conversion Factor =     363.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	3811	10.50	0.963	0.2705	0.5729	618	619
0.800	0.2248	0.800	3448	9.50	0.926	0.2601	0.8415	618	619
0.700	0.1967	1.080	3311	9.12	0.883	0.2481	1.1120	618	619
0.600	0.1686	1.395	3331	9.18	0.834	0.2342	1.4183	618	619
0.500	0.1405	1.815	3493	9.62	0.771	0.2168	1.8302	619	619
0.400	0.1124	2.445	4127	11.37	0.696	0.1956	2.4537	617	619
0.300	0.0843	3.545	5941	16.37	0.604	0.1698	3.5492	617	619
0.200	0.0562	5.445	10552	29.07	0.506	0.1422	5.4468	618	619
0.100	0.0281	7.990	22270	61.35	0.418	0.1175	7.9908	619	619

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:13  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CS-L281.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Light Benchmark .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.
SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000
SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=619 psi
  2.  HYDROSTATIC TEST PRESSURE=860 psi
SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1
SECTION 6.  PRESSURE HISTORY
                  -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=20
SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS   =  62000
CVN           =  40
C =  9.82D-16      n =  2.263
HTP=  860   NO. OF PRESSURE HISTORIES=  20

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  619  PMin =  404  N =     12
   2  PMax =  619  PMin =  318  N =      6
   3  PMax =  619  PMin =  232  N =      6
   4  PMax =  619  PMin =  318  N =      6
  17  PMax =  619  PMin =  318  N =      6
  18  PMax =  619  PMin =  232  N =      7
  19  PMax =  619  PMin =  318  N =      7
  20  PMax =  619  PMin =  404  N =     13

Cycle Spectrum  PMax =  619  PMin =  232

      No. Of Days in the    20 Pressure Pair(s) =      365
No. of Cycles (N's) in the    20 Pressure Pair(s) =      175
                             Conversion Factor =      175.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	4180	23.89	0.962	0.2705	0.5728	619	619
0.800	0.2248	0.800	3786	21.63	0.926	0.2601	0.8414	618	619
0.700	0.1967	1.080	3642	20.81	0.883	0.2481	1.1120	619	619
0.600	0.1686	1.395	3662	20.93	0.834	0.2343	1.4184	618	619
0.500	0.1405	1.815	3830	21.89	0.772	0.2168	1.8302	619	619
0.400	0.1124	2.445	4530	25.89	0.696	0.1954	2.4537	618	619
0.300	0.0843	3.545	6499	37.14	0.603	0.1694	3.5491	618	619
0.200	0.0562	5.445	11550	66.00	0.505	0.1419	5.4468	619	619
0.100	0.0281	7.990	24430	139.60	0.418	0.1175	7.9908	619	619

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:14  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR-VA344.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Very Aggressive Benchmark .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.               1.  MAXIMUM OPERATING PRESSURE=757 psi
  2.  WALL THICKNESS=0.344 in.           2.  HYDROSTATIC TEST PRESSURE=1052 psi
SECTION 3.  MATERIAL ID                SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                 1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi             2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs          SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=44
  7.  YOUNG'S MODULUS,E=30000000
                                        SECTION 7.  da/dN HISTORY
                                          1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in     WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1052   NO. OF PRESSURE HISTORIES=  44

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  757  PMin =  494  N =    250
   2  PMax =  757  PMin =  389  N =    125
   3  PMax =  757  PMin =  284  N =     62
   4  PMax =  757  PMin =  178  N =     12
  41  PMax =  757  PMin =  178  N =     13
  42  PMax =  757  PMin =  284  N =     63
  43  PMax =  757  PMin =  389  N =    125
  44  PMax =  757  PMin =  494  N =    250

Cycle Spectrum  PMax =  757  PMin =    0

        No. Of Days in the    44 Pressure Pair(s) =      365
No. of Cycles (N's) in the    44 Pressure Pair(s) =    3,660
                               Conversion Factor =    3,660.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.580	4325	1.18	0.963	0.3311	0.6484	743	757
0.800	0.2752	0.890	4035	1.10	0.928	0.3191	0.9495	738	757
0.700	0.2408	1.195	3574	0.98	0.882	0.3034	1.2394	756	757
0.600	0.2064	1.550	3410	0.93	0.832	0.2861	1.5820	757	757
0.500	0.1720	2.010	3660	1.00	0.771	0.2653	2.0310	757	757
0.400	0.1376	2.700	4166	1.14	0.697	0.2399	2.7122	754	757
0.300	0.1032	3.840	5939	1.62	0.608	0.2091	3.8460	754	757
0.200	0.0688	5.680	10384	2.84	0.512	0.1762	5.6827	756	757
0.100	0.0344	8.115	21420	5.85	0.425	0.1461	8.1163	757	757

TODAY'S DATE IS 05-24-2004 THE TIME IS 15:32:14 PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR-A344.DAT

SECTION 1. ANALYSIS ID
1. ANALYSIS TITLE IS Deer River Aggressive Benchmark .344
2. CLIENT IS Enbridge
3. PIPELINE NO. IS 365 Actual Days
4. DATE & TIME OF DATA FILE CREATION IS 06-25-2000 12:29:00

SECTION 2. GEOMETRY ID
1. OUTER DIAMETER=34in.
2. WALL THICKNESS=0.344 in.

SECTION 3. MATERIAL ID
1. MATERIAL ID IS X52
2. YIELD STRESS=52000 psi
3. FLOW STRESS=62000 psi
4. CHARPY V-NOTCH=40 ft-lbs
5. CHARPY V-NOTCH AREA=0.124 sq in
6. FRACTURE TOUGHNESS= 340777.1
7. YOUNG'S MODULUS,E=30000000

SECTION 4. PRESSURE HISTORY-MOP, HTP
1. MAXIMUM OPERATING PRESSURE=757 psi
2. HYDROSTATIC TEST PRESSURE=1052 psi

SECTION 5. SCALE & SHIFT FACTORS
1. MEAN SHIFT (ADD.) FACTOR=0
2. SCALE (MULT.) FACTOR=1

SECTION 6. PRESSURE HISTORY -PMAX,PMIN,CYCLE NO.
1. NUMBER OF HISTORIES=44

SECTION 7. da/dN HISTORY
1. NUMBER OF HISTORIES=1

PIPE DIAMETER= 34 in WALL THICKNESS= .344 in
FLOW STRESS = 62000
CVN = 40
C = 9.82D-16 n = 2.263
HTP= 1052 NO. OF PRESSURE HISTORIES= 44
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is 1.00
These results use an eccentricity (e/t) equal to 0.13,
include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
eliminated the TWC crack growth model, outputs final crack lengths,
models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
allows the user to enter stop cycles. This program considers a bending
relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
Change lines 4325 and 4326 for different defect geometries. Corrects KTH
and SBMin & SBMax with eccentricity, added Multiplication factor for Bending

1	PMax = 757	PMin = 494	N = 62
2	PMax = 757	PMin = 389	N = 31
3	PMax = 757	PMin = 284	N = 15
4	PMax = 757	PMin = 178	N = 3
41	PMax = 757	PMin = 178	N = 3
42	PMax = 757	PMin = 284	N = 16
43	PMax = 757	PMin = 389	N = 32
44	PMax = 757	PMin = 494	N = 63

Cycle Spectrum PMax = 757 PMin = 0

No. Of Days in the 44 Pressure Pair(s) = 365
No. of Cycles (N's) in the 44 Pressure Pair(s) = 912
Conversion Factor = 912.00 Cycles/Year

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.580	4331	4.75	0.962	0.3308	0.6467	753	757
0.800	0.2752	0.890	3756	4.12	0.924	0.3177	0.9467	757	757
0.700	0.2408	1.195	3585	3.93	0.882	0.3035	1.2395	755	757
0.600	0.2064	1.550	3553	3.90	0.832	0.2863	1.5818	756	757
0.500	0.1720	2.010	3756	4.12	0.774	0.2663	2.0314	751	757
0.400	0.1376	2.700	4237	4.65	0.697	0.2398	2.7122	754	757
0.300	0.1032	3.840	5990	6.57	0.607	0.2087	3.8460	755	757
0.200	0.0688	5.680	10367	11.37	0.512	0.1762	5.6827	756	757
0.100	0.0344	8.115	21544	23.62	0.425	0.1462	8.1162	756	757

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:14  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR-M344.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Moderate Benchmark .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 365 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID               SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=757 psi
  2.  WALL THICKNESS=0.344 in.          2.  HYDROSTATIC TEST PRESSURE=1052 psi
SECTION 3.  MATERIAL ID               SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs         SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=34
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1052   NO. OF PRESSURE HISTORIES=  34

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  757  PMin =  494  N =     25
   2  PMax =  757  PMin =  389  N =     12
   3  PMax =  757  PMin =  284  N =      6
   4  PMax =  757  PMin =  178  N =      1
  31  PMax =  757  PMin =  178  N =      1
  32  PMax =  757  PMin =  284  N =      6
  33  PMax =  757  PMin =  389  N =     12
  34  PMax =  757  PMin =  494  N =     25

Cycle Spectrum  PMax =  757  PMin =    0

       No. Of Days in the    34 Pressure Pair(s) =      365
No. of Cycles (N's) in the   34 Pressure Pair(s) =      363
                               Conversion Factor =      363.00 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.580	4381	12.07	0.961	0.3307	0.6461	756	757
0.800	0.2752	0.890	3786	10.43	0.924	0.3177	0.9465	757	757
0.700	0.2408	1.195	3667	10.10	0.882	0.3035	1.2394	755	757
0.600	0.2064	1.550	3630	10.00	0.833	0.2864	1.5820	755	757
0.500	0.1720	2.010	3763	10.37	0.771	0.2653	2.0310	757	757
0.400	0.1376	2.700	4313	11.88	0.695	0.2392	2.7120	756	757
0.300	0.1032	3.840	6044	16.65	0.606	0.2084	3.8459	756	757
0.200	0.0688	5.680	10527	29.00	0.511	0.1759	5.6827	757	757
0.100	0.0344	8.115	21914	60.37	0.425	0.1462	8.1161	756	757

TODAY'S DATE IS 05-24-2004 THE TIME IS 15:32:15 PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR-L344.DAT

SECTION 1. ANALYSIS ID
1. ANALYSIS TITLE IS Deer River Light Benchmark .344
2. CLIENT IS Enbridge
3. PIPELINE NO. IS 365 Actual Days
4. DATE & TIME OF DATA FILE CREATION IS 06-25-2000 12:29:00

SECTION 2. GEOMETRY ID
1. OUTER DIAMETER=34in.
2. WALL THICKNESS=0.344 in.

SECTION 3. MATERIAL ID
1. MATERIAL ID IS X52
2. YIELD STRESS=52000 psi
3. FLOW STRESS=62000 psi
4. CHARPY V-NOTCH=40 ft-lbs
5. CHARPY V-NOTCH AREA=0.124 sq in
6. FRACTURE TOUGHNESS= 340777.1
7. YOUNG'S MODULUS,E=30000000

SECTION 4. PRESSURE HISTORY-MOP, HTP
1. MAXIMUM OPERATING PRESSURE=757 psi
2. HYDROSTATIC TEST PRESSURE=1052 psi

SECTION 5. SCALE & SHIFT FACTORS
1. MEAN SHIFT (ADD.) FACTOR=0
2. SCALE (MULT.) FACTOR=1

SECTION 6. PRESSURE HISTORY -PMAX,PMIN,CYCLE NO.
1. NUMBER OF HISTORIES=20

SECTION 7. da/dN HISTORY
1. NUMBER OF HISTORIES=1

PIPE DIAMETER= 34 in WALL THICKNESS= .344 in
FLOW STRESS = 62000
CVN = 40
C = 9.82D-16 n = 2.263
HTP= 1052 NO. OF PRESSURE HISTORIES= 20

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is 1.00
These results use an eccentricity (e/t) equal to 0.13, include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit, eliminated the TWC crack growth model, outputs final crack lengths, models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and allows the user to enter stop cycles. This program considers a bending relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0. Change lines 4325 and 4326 for different defect geometries. Corrects KTH and SBMin & SBMax with eccentricity, added Multiplication factor for Bending

1	PMax = 757	PMin = 494	N = 12
2	PMax = 757	PMin = 389	N = 6
3	PMax = 757	PMin = 284	N = 6
4	PMax = 757	PMin = 389	N = 6
17	PMax = 757	PMin = 389	N = 6
18	PMax = 757	PMin = 284	N = 7
19	PMax = 757	PMin = 389	N = 7
20	PMax = 757	PMin = 494	N = 13

Cycle Spectrum PMax = 757 PMin = 284

No. Of Days in the 20 Pressure Pair(s) = 365
No. of Cycles (N's) in the 20 Pressure Pair(s) = 175
Conversion Factor = 175.00 Cycles/Year

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.580	4799	27.42	0.961	0.3307	0.6462	756	757
0.800	0.2752	0.890	4173	23.85	0.924	0.3177	0.9465	757	757
0.700	0.2408	1.195	4005	22.89	0.882	0.3033	1.2392	757	757
0.600	0.2064	1.550	3967	22.67	0.832	0.2862	1.5819	756	757
0.500	0.1720	2.010	4130	23.60	0.772	0.2654	2.0310	756	757
0.400	0.1376	2.700	4743	27.10	0.695	0.2391	2.7120	757	757
0.300	0.1032	3.840	6637	37.93	0.606	0.2086	3.8460	756	757
0.200	0.0688	5.680	11550	66.00	0.511	0.1759	5.6827	757	757
0.100	0.0344	8.115	24049	137.42	0.425	0.1460	8.1161	757	757

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:15  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2004 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                 SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                 1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.375 in.             2.  HYDROSTATIC TEST PRESSURE=1067 psi
SECTION 3.  MATERIAL ID                 SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                   1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi               2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs           SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1    1.  NUMBER OF HISTORIES=531
  7.  YOUNG'S MODULUS,E=30000000
                                         SECTION 7.  da/dN HISTORY
                                           1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067   NO. OF PRESSURE HISTORIES=  531
KT=  1       MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  469  PMin =  433  N =      1
   2  PMax =  506  PMin =  466  N =      2
   3  PMax =  507  PMin =  479  N =      2
   4  PMax =  507  PMin =  444  N =      2
 528  PMax =  488  PMin =   81  N =      1
 529  PMax =  488  PMin =  329  N =      1
 530  PMax =  412  PMin =  329  N =      1
 531  PMax =  412  PMin =  339  N =      1

Cycle Spectrum  PMax =  597  PMin =    5

        No. Of Days in the   531 Pressure Pair(s) =      182
No. of Cycles (N's) in the   531 Pressure Pair(s) =    1,049
                               Conversion Factor =    2,103.76 Cycles/Year
                          LIFE TO      Years To         a        c
a-INITIAL   c-INITIAL   LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
--------------------------------------------------------------------------
   0.0400   1.181         339517      161.39           0.3514    1.305
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:30  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB04-Q1A.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2004 Q1 .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID               SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.344 in.          2.  HYDROSTATIC TEST PRESSURE=1067 psi
SECTION 3.  MATERIAL ID               SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=0.93
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs         SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in               -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=531
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  531
KT=  1        MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  436  PMin =  403  N =      1
   2  PMax =  471  PMin =  433  N =      2
   3  PMax =  472  PMin =  445  N =      2
   4  PMax =  472  PMin =  413  N =      2
 528  PMax =  454  PMin =   75  N =      1
 529  PMax =  454  PMin =  306  N =      1
 530  PMax =  383  PMin =  306  N =      1
 531  PMax =  383  PMin =  315  N =      1

Cycle Spectrum  PMax =  555  PMin =    5

       No. Of Days in the   531 Pressure Pair(s) =      182
No. of Cycles (N's) in the   531 Pressure Pair(s) =    1,049
                            Conversion Factor =    2,103.76 Cycles/Year
                         LIFE TO      Years To         a        c
a-INITIAL   c-INITIAL    LEAK (Cycles) LEAK (Years)   FINAL    FINAL
-----------------------------------------------------------------------------
  0.0400    1.181        305253      145.10           0.3207     1.282
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:32:53  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB04-Q1B.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2004 Q1 .312
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.312 in.          2.  HYDROSTATIC TEST PRESSURE=1067 psi

SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=0.81
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1    1.  NUMBER OF HISTORIES=531
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .312 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  531
KT=  1        MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  380  PMin =  351  N =       1
   2  PMax =  410  PMin =  377  N =       2
   3  PMax =  411  PMin =  388  N =       2
   4  PMax =  411  PMin =  360  N =       2
 528  PMax =  395  PMin =   66  N =       1
 529  PMax =  395  PMin =  266  N =       1
 530  PMax =  334  PMin =  266  N =       1
 531  PMax =  334  PMin =  275  N =       1

Cycle Spectrum  PMax =  484  PMin =    4

        No. Of Days in the   531 Pressure Pair(s) =      182
No. of Cycles (N's) in the   531 Pressure Pair(s) =    1,049
                                Conversion Factor =    2,103.76 Cycles/Year
                           LIFE TO       Years To        a        c
a-INITIAL   c-INITIAL    LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
-----------------------------------------------------------------------
  0.0400    1.181        308047       146.43          0.2915    1.263
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:33:16  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB04-Q1C.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  HYDROSTATIC TEST PRESSURE=1067 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=0.62

SECTION 6.  PRESSURE HISTORY
                      -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=531

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in     WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067   NO. OF PRESSURE HISTORIES=  531
KT=  1       MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  291  PMin =  268  N =      1
   2  PMax =  314  PMin =  289  N =      2
   3  PMax =  314  PMin =  297  N =      2
   4  PMax =  314  PMin =  275  N =      2
 528  PMax =  303  PMin =   50  N =      1
 529  PMax =  303  PMin =  204  N =      1
 530  PMax =  255  PMin =  204  N =      1
 531  PMax =  255  PMin =  210  N =      1

Cycle Spectrum  PMax =  370  PMin =    3

       No. Of Days in the   531 Pressure Pair(s) =      182
No. of Cycles (N's) in the   531 Pressure Pair(s) =    1,049
                            Conversion Factor =    2,103.76 Cycles/Year
                        LIFE TO     Years To          a        c
a-INITIAL   c-INITIAL     LEAK (Cycles)  LEAK (Years)   FINAL   FINAL
---------------------------------------------------------------------------
  0.0400    1.181        408751      194.30          0.2651    1.248
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:33:43  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CL04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID               SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.               1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  WALL THICKNESS=0.281 in.           2.  HYDROSTATIC TEST PRESSURE=859 psi

SECTION 3.  MATERIAL ID               SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                 1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi             2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs         SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=464
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  859   NO. OF PRESSURE HISTORIES=  464
KT=  1        MOP =  713

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  436  PMin =  370  N =      1
   2  PMax =  436  PMin =  366  N =      1
   3  PMax =  460  PMin =  398  N =      2
   4  PMax =  430  PMin =  397  N =      2
 461  PMax =  291  PMin =   97  N =      1
 462  PMax =  291  PMin =  178  N =      1
 463  PMax =  233  PMin =  178  N =      1
 464  PMax =  233  PMin =  195  N =      1

Cycle Spectrum  PMax =  588  PMin =   23

       No. Of Days in the   464 Pressure Pair(s) =      182
No. of Cycles (N's) in the   464 Pressure Pair(s) =      914
                                Conversion Factor =    1,833.02 Cycles/Year
                         LIFE TO      Years To          a        c
a-INITIAL   c-INITIAL   LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
-----------------------------------------------------------------------------
   0.0400    1.181        141691        77.30          0.2467    1.234
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:33:59  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2004 Q1 .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID                    SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                   1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  WALL THICKNESS=0.344 in.               2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 3.  MATERIAL ID                    SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                     1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi                 2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs              SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                   -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=379

  7.  YOUNG'S MODULUS,E=30000000
                                           SECTION 7.  da/dN HISTORY
                                             1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  897   NO. OF PRESSURE HISTORIES=  379
KT=  1        MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  423  PMin =  359  N =      1
   2  PMax =  428  PMin =  397  N =      2
   3  PMax =  444  PMin =  359  N =      1
   4  PMax =  444  PMin =  345  N =      1
 376  PMax =  484  PMin =  103  N =      1
 377  PMax =  431  PMin =  103  N =      1
 378  PMax =  431  PMin =  255  N =      1
 379  PMax =  377  PMin =  255  N =      1

Cycle Spectrum  PMax =  529  PMin =   16

       No. Of Days in the   379 Pressure Pair(s) =      182
No. of Cycles (N's) in the   379 Pressure Pair(s) =      744
                            Conversion Factor =    1,492.09 Cycles/Year
                          LIFE TO      Years To          a        c
a-INITIAL   c-INITIAL    LEAK (Cycles) LEAK (Years)    FINAL    FINAL
----------------------------------------------------------------------------
  0.0400     1.181        217242       145.60            0.3222    1.284
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:34:08  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR04-Q1A.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2004 Q1 .312
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID               SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  WALL THICKNESS=0.312 in.          2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 3.  MATERIAL ID               SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR=0.92
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs         SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in               -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=379
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .312 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  897   NO. OF PRESSURE HISTORIES=  379
KT=  1       MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  389  PMin =  330  N =      1
   2  PMax =  394  PMin =  365  N =      2
   3  PMax =  408  PMin =  330  N =      1
   4  PMax =  408  PMin =  317  N =      1
 376  PMax =  445  PMin =   95  N =      1
 377  PMax =  397  PMin =   95  N =      1
 378  PMax =  397  PMin =  235  N =      1
 379  PMax =  347  PMin =  235  N =      1

Cycle Spectrum  PMax =  487  PMin =   15

       No. Of Days in the   379 Pressure Pair(s) =      182
No. of Cycles (N's) in the   379 Pressure Pair(s) =      744
                           Conversion Factor =    1,492.09 Cycles/Year
                         LIFE TO      Years To         a        c
a-INITIAL  c-INITIAL    LEAK (Cycles) LEAK (Years)   FINAL    FINAL
---------------------------------------------------------------------
   0.0400    1.181        192199      128.81          0.2908    1.262
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:34:27  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR04-Q1B.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.             1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  WALL THICKNESS=0.281 in.         2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52               1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi           2.  SCALE (MULT.) FACTOR=0.77
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=379
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in     WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  897    NO. OF PRESSURE HISTORIES=  379
KT=  1        MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  326  PMin =  276  N =       1
   2  PMax =  330  PMin =  306  N =       2
   3  PMax =  342  PMin =  276  N =       1
   4  PMax =  342  PMin =  266  N =       1
 376  PMax =  373  PMin =   79  N =       1
 377  PMax =  332  PMin =   79  N =       1
 378  PMax =  332  PMin =  196  N =       1
 379  PMax =  290  PMin =  196  N =       1

Cycle Spectrum  PMax =  407  PMin =   12

        No. Of Days in the   379 Pressure Pair(s) =      182
No. of Cycles (N's) in the   379 Pressure Pair(s) =      744
                             Conversion Factor =     1,492.09 Cycles/Year
                         LIFE TO      Years To          a         c
a-INITIAL   c-INITIAL    LEAK (Cycles)  LEAK (Years)    FINAL     FINAL
-------------------------------------------------------------------------------
   0.0400    1.181        206826       138.62            0.2628     1.246
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:34:35   PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS FW04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Floodwood Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge

  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  HYDROSTATIC TEST PRESSURE=839 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1

SECTION 6.  PRESSURE HISTORY
                -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=371

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in     WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  839   NO. OF PRESSURE HISTORIES=  371
KT=  1        MOP =  713

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  311  PMin =  261  N =      1
   2  PMax =  300  PMin =  255  N =      2
   3  PMax =  311  PMin =  247  N =      2
   4  PMax =  298  PMin =  228  N =      2
 368  PMax =  428  PMin =   42  N =      1
 369  PMax =  328  PMin =   42  N =      1
 370  PMax =  328  PMin =  148  N =      1
 371  PMax =  219  PMin =  148  N =      1

Cycle Spectrum  PMax =  428  PMin =   28

        No. Of Days in the   371 Pressure Pair(s) =      182
No. of Cycles (N's) in the   371 Pressure Pair(s) =      735
                                Conversion Factor =   1,474.04 Cycles/Year
                            LIFE TO       Years To          a        c
a-INITIAL   c-INITIAL    LEAK (Cycles)  LEAK (Years)     FINAL    FINAL
---------------------------------------------------------------------------
  0.0400     1.181         244016        165.54          0.2619    1.245
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:34:56  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2004 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.375 in.            2.  HYDROSTATIC TEST PRESSURE=1067 psi
SECTION 3.  MATERIAL ID                SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi              2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs          SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=531
  7.  YOUNG'S MODULUS,E=30000000
                                        SECTION 7.  da/dN HISTORY
                                          1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in     WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067   NO. OF PRESSURE HISTORIES=  531

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  469  PMin =  433  N =      1
   2  PMax =  506  PMin =  466  N =      2
   3  PMax =  507  PMin =  479  N =      2
   4  PMax =  507  PMin =  444  N =      2
 528  PMax =  488  PMin =   81  N =      1
 529  PMax =  488  PMin =  329  N =      1
 530  PMax =  412  PMin =  329  N =      1
 531  PMax =  412  PMin =  339  N =      1

Cycle Spectrum  PMax =  597  PMin =    5

       No. Of Days in the   531 Pressure Pair(s) =      182
No. of Cycles (N's) in the   531 Pressure Pair(s) =     1,049
                             Conversion Factor =     2,103.76 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.740	34258	16.28	0.972	0.3645	0.8093	594	597
0.800	0.3000	1.140	31464	14.96	0.944	0.3539	1.2001	595	597
0.700	0.2625	1.560	30415	14.46	0.912	0.3421	1.6073	589	597
0.600	0.2250	2.065	30061	14.29	0.878	0.3292	2.1001	574	575
0.500	0.1875	2.765	30062	14.29	0.823	0.3085	2.7874	592	597
0.400	0.1500	3.845	35660	16.95	0.761	0.2855	3.8580	593	597
0.300	0.1125	5.530	54188	25.76	0.708	0.2655	5.5372	571	575
0.200	0.0750	7.870	99296	47.20	0.635	0.2383	7.8734	582	597
0.100	0.0375	10.710	209441	99.56	0.571	0.2141	10.7115	587	597

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:35:29  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CL04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                   SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                   1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  WALL THICKNESS=0.281 in.               2.  HYDROSTATIC TEST PRESSURE=859 psi
SECTION 3.  MATERIAL ID                   SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                     1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi                 2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs             SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                 -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1    1.  NUMBER OF HISTORIES=464
  7.  YOUNG'S MODULUS,E=30000000
                                       SECTION 7.  da/dN HISTORY
                                         1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  859   NO. OF PRESSURE HISTORIES=  464
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  436  PMin =  370  N =     1
   2  PMax =  436  PMin =  366  N =     1
   3  PMax =  460  PMin =  398  N =     2
   4  PMax =  430  PMin =  397  N =     2
 461  PMax =  291  PMin =   97  N =     1
 462  PMax =  291  PMin =  178  N =     1
 463  PMax =  233  PMin =  178  N =     1
 464  PMax =  233  PMin =  195  N =     1

Cycle Spectrum  PMax =  588  PMin =   23

       No. Of Days in the   464 Pressure Pair(s) =      182
No. of Cycles (N's) in the   464 Pressure Pair(s) =      914
                             Conversion Factor =    1,833.02 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	21014	11.46	0.969	0.2723	0.5783	565	588
0.800	0.2248	0.805	18301	9.98	0.933	0.2622	0.8491	586	588
0.700	0.1967	1.080	18272	9.97	0.898	0.2524	1.1157	578	588
0.600	0.1686	1.405	18272	9.97	0.855	0.2403	1.4312	574	588
0.500	0.1405	1.825	19186	10.47	0.803	0.2257	1.8428	569	588
0.400	0.1124	2.455	21957	11.98	0.721	0.2026	2.4647	586	588
0.300	0.0843	3.565	31982	17.45	0.654	0.1837	3.5701	563	588
0.200	0.0562	5.480	55746	30.41	0.544	0.1530	5.4817	581	588
0.100	0.0281	8.030	116984	63.82	0.455	0.1279	8.0305	586	588

TODAY'S DATE IS 05-24-2004 THE TIME IS 15:35:52 PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR04-Q1.DAT
SECTION 1. ANALYSIS ID
1. ANALYSIS TITLE IS Deer River Discharge 2004 Q1 .344
2. CLIENT IS Enbridge
3. PIPELINE NO. IS 91 Actual Days
4. DATE & TIME OF DATA FILE CREATION IS 06-25-2000 12:29:00

SECTION 2. GEOMETRY ID
1. OUTER DIAMETER=34in.
2. WALL THICKNESS=0.344 in.

SECTION 3. MATERIAL ID
1. MATERIAL ID IS X52
2. YIELD STRESS=52000 psi
3. FLOW STRESS=62000 psi
4. CHARPY V-NOTCH=40 ft-lbs
5. CHARPY V-NOTCH AREA=0.124 sq in
6. FRACTURE TOUGHNESS= 340777.1
7. YOUNG'S MODULUS,E=30000000

SECTION 4. PRESSURE HISTORY-MOP, HTP
1. MAXIMUM OPERATING PRESSURE=762 psi
2. HYDROSTATIC TEST PRESSURE=897 psi

SECTION 5. SCALE & SHIFT FACTORS
1. MEAN SHIFT (ADD.) FACTOR=0
2. SCALE (MULT.) FACTOR=1

SECTION 6. PRESSURE HISTORY -PMAX,PMIN,CYCLE NO.
1. NUMBER OF HISTORIES=379

SECTION 7. da/dN HISTORY
1. NUMBER OF HISTORIES=1

PIPE DIAMETER= 34 in WALL THICKNESS= .344 in
FLOW STRESS = 62000
CVN = 40
C = 9.82D-16 n = 2.263
HTP= 897 NO. OF PRESSURE HISTORIES= 379
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is 1.00
These results use an eccentricity (e/t) equal to 0.13,
include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit, eliminated the TWC crack growth model, outputs final crack lengths, models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and allows the user to enter stop cycles. This program considers a bending relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0. Change lines 4325 and 4326 for different defect geometries. Corrects KTH and SBMin & SBMax with eccentricity, added Multiplication factor for Bending

1	PMax =	423	PMin =	359	N =	1
2	PMax =	428	PMin =	397	N =	2
3	PMax =	444	PMin =	359	N =	1
4	PMax =	444	PMin =	345	N =	1
376	PMax =	484	PMin =	103	N =	1
377	PMax =	431	PMin =	103	N =	1
378	PMax =	431	PMin =	255	N =	1
379	PMax =	377	PMin =	255	N =	1

Cycle Spectrum PMax = 529 PMin = 16

No. Of Days in the 379 Pressure Pair(s) = 182
No. of Cycles (N's) in the 379 Pressure Pair(s) = 744
Conversion Factor = 1,492.09 Cycles/Year

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.850	14874	9.97	0.966	0.3322	0.8918	529	529
0.800	0.2752	1.330	14130	9.47	0.930	0.3198	1.3652	527	529
0.700	0.2408	1.860	13386	8.97	0.889	0.3058	1.8865	523	529
0.600	0.2064	2.540	12895	8.64	0.843	0.2899	2.5585	516	525
0.500	0.1720	3.560	13639	9.14	0.780	0.2682	3.5710	524	525
0.400	0.1376	5.180	18594	12.46	0.715	0.2461	5.1860	522	529
0.300	0.1032	7.560	32528	21.80	0.654	0.2250	7.5633	515	525
0.200	0.0688	10.580	64975	43.55	0.585	0.2012	10.5814	522	525
0.100	0.0344	14.110	142098	95.23	0.520	0.1788	14.1107	528	529

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:36:16  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS FW04-Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Floodwood Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                  SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                 1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  WALL THICKNESS=0.281 in.             2.  HYDROSTATIC TEST PRESSURE=839 psi
SECTION 3.  MATERIAL ID                  SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                   1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi               2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs             SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                  -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1    1.  NUMBER OF HISTORIES=371
  7.  YOUNG'S MODULUS,E=30000000
                                         SECTION 7.  da/dN HISTORY
                                           1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in     WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  839   NO. OF PRESSURE HISTORIES=  371

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  311  PMin =  261  N =       1
   2  PMax =  300  PMin =  255  N =       2
   3  PMax =  311  PMin =  247  N =       2
   4  PMax =  298  PMin =  228  N =       2
 368  PMax =  428  PMin =   42  N =       1
 369  PMax =  328  PMin =   42  N =       1
 370  PMax =  328  PMin =  148  N =       1
 371  PMax =  219  PMin =  148  N =       1

Cycle Spectrum  PMax =  428  PMin =   28

        No. Of Days in the   371 Pressure Pair(s) =      182
No. of Cycles (N's) in the   371 Pressure Pair(s) =      735
                              Conversion Factor =    1,474.04 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.565	36011	24.43	0.980	0.2755	0.6221	411	428
0.800	0.2248	0.865	33071	22.44	0.958	0.2692	0.9148	426	428
0.700	0.1967	1.170	32336	21.94	0.933	0.2623	1.2104	424	428
0.600	0.1686	1.530	32336	21.94	0.908	0.2553	1.5614	407	428
0.500	0.1405	2.010	33071	22.44	0.871	0.2449	2.0319	406	428
0.400	0.1124	2.750	38216	25.93	0.823	0.2312	2.7635	404	428
0.300	0.0843	4.055	54386	36.90	0.753	0.2115	4.0615	413	428
0.200	0.0562	6.165	97751	66.32	0.695	0.1952	6.1680	403	428
0.100	0.0281	8.860	205061	139.12	0.622	0.1748	8.8611	416	428

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:40:10  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CL00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Cass Lake Discharge 2000 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.               1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  WALL THICKNESS=0.281 in.           2.  HYDROSTATIC TEST PRESSURE=859 psi
SECTION 3.  MATERIAL ID                SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                 1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi             2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs          SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=711
  7.  YOUNG'S MODULUS,E=30000000
                                        SECTION 7.  da/dN HISTORY
                                          1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  859   NO. OF PRESSURE HISTORIES=  711

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  400  PMin =  335  N =      2
   2  PMax =  455  PMin =  392  N =      2
   3  PMax =  516  PMin =  458  N =      2
   4  PMax =  546  PMin =  483  N =      2
 708  PMax =  604  PMin =   50  N =      1
 709  PMax =  593  PMin =   50  N =      1
 710  PMax =  593  PMin =  458  N =      1
 711  PMax =  593  PMin =  458  N =      1

Cycle Spectrum  PMax =  616  PMin =    1

       No. Of Days in the    711 Pressure Pair(s) =      182
No. of Cycles (N's) in the   711 Pressure Pair(s) =     1,413
                                Conversion Factor =     2,833.76 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.2529	0.525	5260	1.86	0.965	0.2711	0.5745	603	604
0.800	0.2248	0.805	4764	1.68	0.929	0.2610	0.8473	603	604
0.700	0.1967	1.080	4658	1.64	0.889	0.2499	1.1134	603	605
0.600	0.1686	1.405	4658	1.64	0.842	0.2367	1.4293	599	605
0.500	0.1405	1.825	4838	1.71	0.783	0.2199	1.8410	601	608
0.400	0.1124	2.455	5645	1.99	0.700	0.1968	2.4638	611	616
0.300	0.0843	3.565	8184	2.89	0.620	0.1741	3.5694	600	603
0.200	0.0562	5.480	14549	5.13	0.524	0.1472	5.4818	600	605
0.100	0.0281	8.030	30594	10.80	0.435	0.1221	8.0306	604	608

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:40:24  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2000 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                 SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.                1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.375 in.            2.  HYDROSTATIC TEST PRESSURE=1067 psi
SECTION 3.  MATERIAL ID                 SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi              2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs           SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=624
  7.  YOUNG'S MODULUS,E=30000000
                                         SECTION 7.  da/dN HISTORY
                                           1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  1067   NO. OF PRESSURE HISTORIES=  624

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  564  PMin = -489  N =       2
   2  PMax =  680  PMin =  614  N =       2
   3  PMax =  749  PMin =  685  N =       2
   4  PMax =  762  PMin =   34  N =       1
 621  PMax =  754  PMin =    1  N =       1
 622  PMax =  754  PMin =    7  N =       1
 623  PMax =  707  PMin =    7  N =       1
 624  PMax =  707  PMin =  620  N =       1

Cycle Spectrum  PMax =  766  PMin =     0

       No. Of Days in the   624 Pressure Pair(s) =      182
No. of Cycles (N's) in the   624 Pressure Pair(s) =     1,238
                           Conversion Factor =     2,482.80 Cycles/Year
```

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3375	0.740	4027	1.62	0.959	0.3596	0.7954	741	749
0.800	0.3000	1.140	3636	1.46	0.915	0.3432	1.1857	753	755
0.700	0.2625	1.560	3506	1.41	0.868	0.3255	1.5946	749	753
0.600	0.2250	2.065	3506	1.41	0.815	0.3058	2.0895	741	753
0.500	0.1875	2.765	3634	1.46	0.744	0.2789	2.7798	752	753
0.400	0.1500	3.845	4462	1.80	0.662	0.2481	3.8530	758	762
0.300	0.1125	5.530	7046	2.84	0.584	0.2190	5.5341	749	757
0.200	0.0750	7.870	13128	5.29	0.494	0.1852	7.8720	760	762
0.100	0.0375	10.710	28392	11.44	0.425	0.1595	10.7109	750	752

TODAY'S DATE IS 05-24-2004 THE TIME IS 15:40:49 PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR00Q1.DAT

SECTION 1. ANALYSIS ID
1. ANALYSIS TITLE IS Deer River Discharge 2000 Q1 .344
2. CLIENT IS Enbridge
3. PIPELINE NO. IS 91 Actual Days
4. DATE & TIME OF DATA FILE CREATION IS 06-25-2000 12:29:00

SECTION 2. GEOMETRY ID
1. OUTER DIAMETER=34in.
2. WALL THICKNESS=0.344 in.

SECTION 3. MATERIAL ID
1. MATERIAL ID IS X52
2. YIELD STRESS=52000 psi
3. FLOW STRESS=62000 psi
4. CHARPY V-NOTCH=40 ft-lbs
5. CHARPY V-NOTCH AREA=0.124 sq in
6. FRACTURE TOUGHNESS= 340777.1
7. YOUNG'S MODULUS,E=30000000

SECTION 4. PRESSURE HISTORY-MOP, HTP
1. MAXIMUM OPERATING PRESSURE=762 psi
2. HYDROSTATIC TEST PRESSURE=897 psi

SECTION 5. SCALE & SHIFT FACTORS
1. MEAN SHIFT (ADD.) FACTOR=0
2. SCALE (MULT.) FACTOR=1

SECTION 6. PRESSURE HISTORY -PMAX,PMIN,CYCLE NO.
1. NUMBER OF HISTORIES=689

SECTION 7. da/dN HISTORY
1. NUMBER OF HISTORIES=1

PIPE DIAMETER= 34 in WALL THICKNESS= .344 in
FLOW STRESS = 62000
CVN = 40
C = 9.82D-16 n = 2.263
HTP= 897 NO. OF PRESSURE HISTORIES= 689
These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is 1.00
These results use an eccentricity (e/t) equal to 0.13, include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit, eliminated the TWC crack growth model, outputs final crack lengths, models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and allows the user to enter stop cycles. This program considers a bending relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0. Change lines 4325 and 4326 for different defect geometries. Corrects KTH and SBMin & SBMax with eccentricity, added Multiplication factor for Bending

1	PMax = 454	PMin = 389	N =	2
2	PMax = 478	PMin = 405	N =	2
3	PMax = 631	PMin = 571	N =	2
4	PMax = 653	PMin = 560	N =	2
686	PMax = 664	PMin = 95	N =	1
687	PMax = 664	PMin = 447	N =	1
688	PMax = 539	PMin = 447	N =	1
689	PMax = 539	PMin = 447	N =	1

Cycle Spectrum PMax = 698 PMin = 27

No. Of Days in the 689 Pressure Pair(s) = 182
No. of Cycles (N's) in the 689 Pressure Pair(s) = 1,364
Conversion Factor = 2,735.49 Cycles/Year

a/t	a INITIAL	c INITIAL	Cyles to LEAK	Years To LEAK	a/t FINAL	a FINAL	c FINAL	PFail	PMax
0.900	0.3096	0.850	2719	0.99	0.944	0.3248	0.8768	697	698
0.800	0.2752	1.330	2719	0.99	0.891	0.3065	1.3529	682	698
0.700	0.2408	1.860	2640	0.97	0.832	0.2860	1.8767	676	678
0.600	0.2064	2.540	2638	0.96	0.765	0.2633	2.5510	671	675
0.500	0.1720	3.560	2871	1.05	0.682	0.2345	3.5661	680	685
0.400	0.1376	5.180	4083	1.49	0.590	0.2030	5.1830	689	698
0.300	0.1032	7.560	7689	2.81	0.519	0.1785	7.5616	674	678
0.200	0.0688	10.580	15512	5.67	0.430	0.1480	10.5807	683	685
0.100	0.0344	14.110	34091	12.46	0.338	0.1164	14.1103	696	698

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:41:18  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS FW00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Floodwood Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID                SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.               1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  WALL THICKNESS=0.281 in.           2.  HYDROSTATIC TEST PRESSURE=839 psi
SECTION 3.  MATERIAL ID                SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                 1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi             2.  SCALE (MULT.) FACTOR=1
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs          SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in                -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1    1.  NUMBER OF HISTORIES=617
  7.  YOUNG'S MODULUS,E=30000000
                                        SECTION 7.  da/dN HISTORY
                                          1.  NUMBER OF HISTORIES=1
PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  839   NO. OF PRESSURE HISTORIES=  617

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  334  PMin =  280  N =      2
   2  PMax =  571  PMin =  489  N =      2
   3  PMax =  560  PMin =  441  N =      2
   4  PMax =  572  PMin =   91  N =      2
 614  PMax =  610  PMin =   58  N =      1
 615  PMax =  591  PMin =   58  N =      1
 616  PMax =  591  PMin =  465  N =      1
 617  PMax =  526  PMin =  465  N =      1

Cycle Spectrum  PMax =  623  PMin =   48

        No. Of Days in the   617 Pressure Pair(s) =      182
No. of Cycles (N's) in the   617 Pressure Pair(s) =    1,223
                                Conversion Factor =    2,452.72 Cycles/Year
```

	a	c	Cyles to	Years To	a/t	a	c		
a/t	INITIAL	INITIAL	LEAK	LEAK	FINAL	FINAL	FINAL	PFail	PMax
0.900	0.2529	0.565	3977	1.62	0.959	0.2696	0.6058	612	614
0.800	0.2248	0.865	3660	1.49	0.918	0.2578	0.8994	616	623
0.700	0.1967	1.170	3601	1.47	0.872	0.2450	1.1966	613	613
0.600	0.1686	1.530	3601	1.47	0.817	0.2297	1.5488	612	613
0.500	0.1405	2.010	3859	1.57	0.756	0.2125	2.0223	605	608
0.400	0.1124	2.750	4648	1.90	0.670	0.1884	2.7566	613	616
0.300	0.0843	4.055	7092	2.89	0.586	0.1646	4.0581	604	606
0.200	0.0562	6.165	12907	5.26	0.478	0.1344	6.1662	618	619
0.100	0.0281	8.860	27885	11.37	0.400	0.1124	8.8604	613	616

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:42:00  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2000 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00
SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.375 in.
SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000
SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  HYDROSTATIC TEST PRESSURE=1067 psi
SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1
SECTION 6.  PRESSURE HISTORY
                  -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=624
SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16        n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  624

KT=  1         MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  564  PMin =  489  N =      2
   2  PMax =  680  PMin =  614  N =      2
   3  PMax =  749  PMin =  685  N =      2
   4  PMax =  762  PMin =   34  N =      1
 621  PMax =  754  PMin =    1  N =      1
 622  PMax =  754  PMin =    7  N =      1
 623  PMax =  707  PMin =    7  N =      1
 624  PMax =  707  PMin =  620  N =      1

 Cycle Spectrum  PMax =  766  PMin =    0

            No. Of Days in the   624 Pressure Pair(s) =       182
 No. of Cycles (N's) in the   624 Pressure Pair(s) =     1,238
                           Conversion Factor =     2,482.80 Cycles/Year
                              LIFE TO      Years To        a        c
 a-INITIAL   c-INITIAL     LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
 -------------------------------------------------------------------------
   0.0400     1.181          48074        19.36          0.3401    1.293
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:43:06  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2000 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.375 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  HYDROSTATIC TEST PRESSURE=1067 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR= .93

SECTION 6.  PRESSURE HISTORY
              -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=624

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  624
KT=  1        MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  525  PMin =  455  N =     2
   2  PMax =  632  PMin =  571  N =     2
   3  PMax =  697  PMin =  637  N =     2
   4  PMax =  709  PMin =   32  N =     1
 621  PMax =  701  PMin =    1  N =     1
 622  PMax =  701  PMin =    7  N =     1
 623  PMax =  658  PMin =    7  N =     1
 624  PMax =  658  PMin =  577  N =     1

Cycle Spectrum  PMax =  712  PMin =    0

        No. Of Days in the   624 Pressure Pair(s) =      182
No. of Cycles (N's) in the   624 Pressure Pair(s) =    1,238
                                 Conversion Factor =    2,482.80 Cycles/Year
```

a-INITIAL	c-INITIAL	LIFE TO LEAK (Cycles)	Years To LEAK (Years)	a FINAL	c FINAL
0.0400	1.181	57581	23.19	0.3445	1.298

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:43:51  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2000 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.             1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.375 in.         2.  HYDROSTATIC TEST PRESSURE=1067 psi

SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52               1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi           2.  SCALE (MULT.) FACTOR= .81
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in             -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=624
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in     WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  624
KT=  1        MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  457  PMin =  396  N =      2
   2  PMax =  551  PMin =  497  N =      2
   3  PMax =  607  PMin =  555  N =      2
   4  PMax =  617  PMin =   28  N =      1
 621  PMax =  611  PMin =    1  N =      1
 622  PMax =  611  PMin =    6  N =      1
 623  PMax =  573  PMin =    6  N =      1
 624  PMax =  573  PMin =  502  N =      1

Cycle Spectrum  PMax =  620  PMin =     0

       No. Of Days in the   624 Pressure Pair(s) =       182
No. of Cycles (N's) in the   624 Pressure Pair(s) =     1,238
                               Conversion Factor =    2,482.80 Cycles/Year
                          LIFE TO       Years To         a        c
a-INITIAL   c-INITIAL    LEAK (Cycles)  LEAK (Years)    FINAL    FINAL
-----------------------------------------------------------------------------
  0.0400    1.181          80463         32.41           0.3497    1.304
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:44:37  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CB00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Clearbrook Discharge 2000 Q1 .375
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.              1.  MAXIMUM OPERATING PRESSURE=907 psi
  2.  WALL THICKNESS=0.375 in.          2.  HYDROSTATIC TEST PRESSURE=1067 psi

SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52                1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi            2.  SCALE (MULT.) FACTOR= .62
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=624
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in    WALL THICKNESS=  .375 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  1067    NO. OF PRESSURE HISTORIES=  624
KT=  1        MOP =  907

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  350  PMin =  303  N =      2
   2  PMax =  422  PMin =  381  N =      2
   3  PMax =  464  PMin =  425  N =      2
   4  PMax =  472  PMin =   21  N =      1
 621  PMax =  467  PMin =    1  N =      1
 622  PMax =  467  PMin =    4  N =      1
 623  PMax =  438  PMin =    4  N =      1
 624  PMax =  438  PMin =  384  N =      1

Cycle Spectrum  PMax =  475  PMin =    0

        No. Of Days in the   624 Pressure Pair(s) =      182
No. of Cycles (N's) in the   624 Pressure Pair(s) =    1,238
                                 Conversion Factor =    2,482.80 Cycles/Year
                             LIFE TO       Years To         a        c
a-INITIAL   c-INITIAL     LEAK (Cycles)  LEAK (Years)    FINAL    FINAL
---------------------------------------------------------------------------
   0.0400    1.181         152066        61.25             0.3585     1.314
```

TODAY'S DATE IS 05-24-2004 THE TIME IS 15:45:14 PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS CL00Q1.DAT

SECTION 1. ANALYSIS ID
1. ANALYSIS TITLE IS Cass Lake Discharge 2000 Q1 .281
2. CLIENT IS Enbridge
3. PIPELINE NO. IS 91 Actual Days
4. DATE & TIME OF DATA FILE CREATION IS 06-25-2000 12:29:00

SECTION 2. GEOMETRY ID
1. OUTER DIAMETER=34in.
2. WALL THICKNESS=0.281 in.

SECTION 3. MATERIAL ID
1. MATERIAL ID IS X52
2. YIELD STRESS=52000 psi
3. FLOW STRESS=62000 psi
4. CHARPY V-NOTCH=40 ft-lbs
5. CHARPY V-NOTCH AREA=0.124 sq in
6. FRACTURE TOUGHNESS= 340777.1
7. YOUNG'S MODULUS,E=30000000

SECTION 4. PRESSURE HISTORY-MOP, HTP
1. MAXIMUM OPERATING PRESSURE=713 psi
2. HYDROSTATIC TEST PRESSURE=859 psi

SECTION 5. SCALE & SHIFT FACTORS
1. MEAN SHIFT (ADD.) FACTOR=0
2. SCALE (MULT.) FACTOR=1

SECTION 6. PRESSURE HISTORY -PMAX,PMIN,CYCLE NO.
1. NUMBER OF HISTORIES=711

SECTION 7. da/dN HISTORY
1. NUMBER OF HISTORIES=1

PIPE DIAMETER= 34 in WALL THICKNESS= .281 in
FLOW STRESS = 62000
CVN = 40
C = 9.82D-16 n = 2.263
HTP= 859 NO. OF PRESSURE HISTORIES= 711
KT= 1 MOP = 713

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is 1.00
These results use an eccentricity (e/t) equal to 0.13,
include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit, eliminated the TWC crack growth model, outputs final crack lengths, models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and allows the user to enter stop cycles. This program considers a bending relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0. Change lines 4325 and 4326 for different defect geometries. Corrects KTH and SBMin & SBMax with eccentricity, added Multiplication factor for Bending

1	PMax =	400	PMin =	335	N =	2
2	PMax =	455	PMin =	392	N =	2
3	PMax =	516	PMin =	458	N =	2
4	PMax =	546	PMin =	483	N =	2
708	PMax =	604	PMin =	50	N =	1
709	PMax =	593	PMin =	50	N =	1
710	PMax =	593	PMin =	458	N =	1
711	PMax =	593	PMin =	458	N =	1

Cycle Spectrum PMax = 616 PMin = 1

No. Of Days in the 711 Pressure Pair(s) = 182
No. of Cycles (N's) in the 711 Pressure Pair(s) = 1,413
Conversion Factor = 2,833.76 Cycles/Year

a-INITIAL	c-INITIAL	LIFE TO LEAK (Cycles)	Years To LEAK (Years)	a FINAL	c FINAL
0.0400	1.181	37337	13.18	0.2440	1.232

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:45:56  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2000 Q1 .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.344 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1

SECTION 6.  PRESSURE HISTORY
            -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=689

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1


PIPE DIAMETER=  34 in     WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  897   NO. OF PRESSURE HISTORIES=  689
KT=  1        MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  454  PMin =  389  N =      2
   2  PMax =  478  PMin =  405  N =      2
   3  PMax =  631  PMin =  571  N =      2
   4  PMax =  653  PMin =  560  N =      2
 686  PMax =  664  PMin =   95  N =      1
 687  PMax =  664  PMin =  447  N =      1
 688  PMax =  539  PMin =  447  N =      1
 689  PMax =  539  PMin =  447  N =      1

Cycle Spectrum  PMax =  698  PMin =   27

           No. Of Days in the    689 Pressure Pair(s) =      182
No. of Cycles (N's) in the    689 Pressure Pair(s) =    1,364
                                  Conversion Factor =    2,735.49 Cycles/Year
                                LIFE TO      Years To         a        c
a-INITIAL   c-INITIAL       LEAK (Cycles)  LEAK (Years)    FINAL    FINAL
----------------------------------------------------------------------------
  0.0400     1.181             58351         21.33         0.3102    1.272
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:46:40   PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2000 Q1 .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.344 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR= .92

SECTION 6.  PRESSURE HISTORY
                 -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=689

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .344 in
FLOW STRESS   =  62000
CVN           =  40
C =  9.82D-16      n =  2.263
HTP=  897    NO. OF PRESSURE HISTORIES=  689
KT=  1        MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  418  PMin =  358  N =      2
   2  PMax =  440  PMin =  373  N =      2
   3  PMax =  581  PMin =  525  N =      2
   4  PMax =  601  PMin =  515  N =      2
 686  PMax =  611  PMin =   87  N =      1
 687  PMax =  611  PMin =  411  N =      1
 688  PMax =  496  PMin =  411  N =      1
 689  PMax =  496  PMin =  411  N =      1

Cycle Spectrum  PMax =  642  PMin =   25

        No. Of Days in the   689 Pressure Pair(s) =      182
No. of Cycles (N's) in the   689 Pressure Pair(s) =    1,364
                             Conversion Factor =    2,735.49 Cycles/Year
                          LIFE TO      Years To         a        c
a-INITIAL   c-INITIAL   LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
---------------------------------------------------------------------------
  0.0400     1.181        71869        26.27          0.3150    1.277
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:47:26  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS DR00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Deer River Discharge 2000 Q1 .344
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID              SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  OUTER DIAMETER=34in.             1.  MAXIMUM OPERATING PRESSURE=762 psi
  2.  WALL THICKNESS=0.344 in.         2.  HYDROSTATIC TEST PRESSURE=897 psi

SECTION 3.  MATERIAL ID              SECTION 5.  SCALE & SHIFT FACTORS
  1.  MATERIAL ID IS X52               1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  YIELD STRESS=52000 psi           2.  SCALE (MULT.) FACTOR= .77
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs        SECTION 6.  PRESSURE HISTORY
  5.  CHARPY V-NOTCH AREA=0.124 sq in              -PMAX,PMIN,CYCLE NO.
  6.  FRACTURE TOUGHNESS= 340777.1   1.  NUMBER OF HISTORIES=689
  7.  YOUNG'S MODULUS,E=30000000
                                      SECTION 7.  da/dN HISTORY
                                        1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .344 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16       n =  2.263
HTP=  897   NO. OF PRESSURE HISTORIES=  689
KT=  1        MOP =  762

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is   1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1  PMax =  350  PMin =  300  N =      2
   2  PMax =  368  PMin =  312  N =      2
   3  PMax =  486  PMin =  440  N =      2
   4  PMax =  503  PMin =  431  N =      2
 686  PMax =  511  PMin =   73  N =      1
 687  PMax =  511  PMin =  344  N =      1
 688  PMax =  415  PMin =  344  N =      1
 689  PMax =  415  PMin =  344  N =      1

Cycle Spectrum  PMax =  537  PMin =   21

       No. Of Days in the   689 Pressure Pair(s) =      182
No. of Cycles (N's) in the   689 Pressure Pair(s) =    1,364
                               Conversion Factor =    2,735.49 Cycles/Year
                           LIFE TO      Years To        a        c
a-INITIAL   c-INITIAL    LEAK (Cycles)  LEAK (Years)   FINAL    FINAL
---------------------------------------------------------------------------
  0.0400    1.181        110887       40.54           0.3226     1.284
```

```
TODAY'S DATE IS 05-24-2004   THE TIME IS 15:47:59  PL15.BAS 3/19/97
THE DATA FILENAME IN USE IS FW00Q1.DAT
SECTION 1.  ANALYSIS ID
  1.  ANALYSIS TITLE IS Floodwood Discharge 2004 Q1 .281
  2.  CLIENT IS Enbridge
  3.  PIPELINE NO. IS 91 Actual Days
  4.  DATE & TIME OF DATA FILE CREATION IS 06-25-2000   12:29:00

SECTION 2.  GEOMETRY ID
  1.  OUTER DIAMETER=34in.
  2.  WALL THICKNESS=0.281 in.

SECTION 3.  MATERIAL ID
  1.  MATERIAL ID IS X52
  2.  YIELD STRESS=52000 psi
  3.  FLOW STRESS=62000 psi
  4.  CHARPY V-NOTCH=40 ft-lbs
  5.  CHARPY V-NOTCH AREA=0.124 sq in
  6.  FRACTURE TOUGHNESS= 340777.1
  7.  YOUNG'S MODULUS,E=30000000

SECTION 4.  PRESSURE HISTORY-MOP, HTP
  1.  MAXIMUM OPERATING PRESSURE=713 psi
  2.  HYDROSTATIC TEST PRESSURE=839 psi

SECTION 5.  SCALE & SHIFT FACTORS
  1.  MEAN SHIFT (ADD.) FACTOR=0
  2.  SCALE (MULT.) FACTOR=1

SECTION 6.  PRESSURE HISTORY
                -PMAX,PMIN,CYCLE NO.
  1.  NUMBER OF HISTORIES=617

SECTION 7.  da/dN HISTORY
  1.  NUMBER OF HISTORIES=1

PIPE DIAMETER=  34 in    WALL THICKNESS=  .281 in
FLOW STRESS  =  62000
CVN          =  40
C =  9.82D-16      n =  2.263
HTP=  839    NO. OF PRESSURE HISTORIES=  617
KT=  1        MOP =  713

These results DO NOT consider THRESHOLD effects
These results DO consider BENDING
The bending multiplication factor is    1.00
These results use an eccentricity (e/t) equal to  0.13,
 include Fc (by WAM), Qmax=Qmin, & allows C1 to grow greater than Cinit,
 eliminated the TWC crack growth model, outputs final crack lengths,
 models area as an elliptical shape (PI/4), and 2c/Rt^.5 <= OR > 9, and
 allows the user to enter stop cycles.  This program considers a bending
 relationship for a SPECIFIC DEFECT GEOMETRY with an eccentricity of 0.0.
 Change lines 4325 and 4326 for different defect geometries.  Corrects KTH
 and SBMin & SBMax with eccentricity, added Multiplication factor for Bending
   1   PMax =  334   PMin =  280   N =      2
   2   PMax =  571   PMin =  489   N =      2
   3   PMax =  560   PMin =  441   N =      2
   4   PMax =  572   PMin =   91   N =      2
 614   PMax =  610   PMin =   58   N =      1
 615   PMax =  591   PMin =   58   N =      1
 616   PMax =  591   PMin =  465   N =      1
 617   PMax =  526   PMin =  465   N =      1

Cycle Spectrum  PMax =  623   PMin =   48

       No. Of Days in the   617 Pressure Pair(s) =      182
No. of Cycles (N's) in the  617 Pressure Pair(s) =    1,223
                             Conversion Factor =    2,452.72 Cycles/Year
                          LIFE TO      Years To          a       c
a-INITIAL   c-INITIAL    LEAK (Cycles) LEAK (Years)    FINAL   FINAL
--------------------------------------------------------------------------
   0.0400    1.181         35055        14.29            0.2435    1.232
```

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Compliance
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ENBRIDGE™

May 19, 2005

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

Attached are two copies of the Kiefner & Associates report entitled "Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-inch Line 3 – Quarter 3 of 2004", as requested in your December 9, 2003 letter to Enbridge.

No field activities were undertaken (i.e., excavations or inline inspection) during the third quarter of 2004. Activities related to the pipe removed from Four-Legged Lake continued through the third quarter. These include inline inspection pull-through testing and burst testing.

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J. Willoughby

Mark J. Willoughby

Attachments

c/att: Brian Pierzina
Joy Kadnar
Michael McGrath
Walter Kresic

PIPELINE INTEGRITY

MAY - 5 2005

Kiefner & Associates, Inc.

April 27, 2005

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

RE: Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3
Quarter 3 of 2004

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the third quarter of 2004.

The current analysis process was identical to that used for the previous analyses, the first quarter of 2004 (KAI report 0023-0404), the second quarter of 2004 letter report and the June 2003 fatigue analysis (KAI report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles occurring in the first quarter of 2000 (pressure data used in the June 2003 analysis) are conservative compared to current operations. In addition, Table 1 shows that there has not been a substantial change in operation for the first 3 quarters of 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that theoretically could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inches in depth and

2.36 inches in length. Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 89.7 years was calculated using the 2004 Quarter 3 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by slightly over 75 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 45 years of the date of the previous Ultrascan CD in-line inspection. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

If you have any questions or comments, please call me.

Sincerely,

Michael J. Rosenfeld
President
Senior Structural Engineer

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Clearbrook 2004 Q3	***19.6***	***18.1***	***17.1***	***17.1***	***17.1***	***20.1***	***30.7***	***55.9***	***117.9***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Deer River 2004 Q3	***10.1***	***9.6***	***9.1***	***8.6***	***9.3***	***12.6***	***21.9***	***44.1***	***96.8***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Cass Lake 2004 Q3	***13.8***	***12.6***	***12.2***	***12.2***	***12.6***	***14.6***	***20.7***	***35.9***	***75.3***
	Floodwood 2004 Q2	***17.2***	***16.1***	***15.6***	***15.4***	***15.7***	***18.3***	***26.2***	***47.0***	***99.1***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q3	***24.0***	***22.2***	***21.7***	***21.5***	***22.0***	***25.5***	***36.6***	***65.9***	***138.4***
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***

* Times to failure provide only a comparative analysis to the benchmark cycles and previous operating cycles.

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Reassessment Interval Based on 2004 Quarter 3 Cycles	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36 in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36 in long Defect, years	2004 Quarter 3 Time to Failure of 0.04-in deep, 2.36 in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	2097	161.4	130.3	191.0	19.4
MP 912.9	Transition to 0.344-inch WT	2088	145.1	117.2	171.8	23.2
MP 917.5	Transition to 0.312-inch WT	2089	146.4	118.2	173.3	32.4
MP 925.8	Transition to 0.281-inch WT	2117	194.3	157.2	230.3	61.3
Cass Lake	Cass Lake discharge pressures	2047	77.3	63.6	89.7	13.2
Deer River	Deer River discharge pressures	2076	145.6	113.1	148.2	21.3
MP 999.9	Transition to 0.312-inch WT	2068	128.8	100.0	131.1	26.3
MP 1007.2	Transition to 0.281-inch WT	2073	138.6	107.8	141.4	40.5
Floodwood	Floodwood discharge pressures	2085	165.5	117.8	165.2	14.3

* Reassessment interval is calculated from the date of the CD Tool Run in 2002, applying a factor of safety of 2.

Compl Reg
Stewart –
Phil

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

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December 9, 2004

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Rm 462E
Kansas City, MO 64106

Re: CPF No. 3-2002-5017H
Line 3 – 34-inch Pipeline from US/Canadian Border to Superior, WI

Dear Mr. Huntoon:

Attached are two copies of the Kiefner & Associates report entitled "Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-inch Line 3 – Quarter 2 of 2004", as requested in your December 9, 2003 letter to Enbridge.

No field activities were undertaken (i.e., excavations or inline inspection) during the second quarter of 2004. However, burst testing was done on the pipe segment removed from Four-Legged Lake. Inline inspection pull-through testing was also done using pipe removed from Four-Legged Lake.

Should you require further information, please contact me at (715) 394-1534.

Sincerely,

Mark J. Willoughby

Mark J. Willoughby

Attachments

c/att: Brian Pierzina
Joy Kadnar
Michael McGrath

PIPELINE INTEGRITY

NOV - 1 2004

Kiefner & Associates, Inc.

October 25, 2004

Sean Keane
Enbridge Pipelines, Inc.
10201 Jasper Avenue
P.O. Box 398
Edmonton, AB T5J 2J9
Canada

RE: Quarterly Analysis to Assess the Effects of Pressure Cycles on Enbridge's 34-Inch Line 3
Quarter 2 of 2004

Dear Mr. Keane:

In accordance with Enbridge's commitment to the Office of Pipeline Safety (OPS) for return to service after the Cohasset failure, the pressure cycles occurring on the 34-inch Line 3 operating between Clearbrook, Minnesota and Superior, Wisconsin were analyzed to determine if the pressure data used in the June 2003 fatigue analysis (KAI report 0023-0205) was adequately conservative relative to the actual operating conditions. The current analysis pertains to pressure cycles that occurred during the second quarter of 2004.

The analysis process was identical to that used for the previous analysis, namely the first quarter of 2004 (KAI report 0023-0404) and the June 2003 fatigue analysis (KAI report 0023-0205). The details of the analysis are well documented within said reports.

Table 1 compares Line 3 pressure cycling to our benchmark cycles. It is evident from Table 1 that the pressure cycles used in the June 2003 analysis are conservative compared to current operations. In addition, Table 1 shows that there has not been a substantial change in operation since Quarter 1 of 2004.

The times to failure in Table 1 are for a series of flaws ranging from 90-percent through-the-wall thickness to 10 percent in increments of 10 percent. These are flaws that could have just survived the previous hydrostatic test pressure levels. It is not expected that defects of the deepest magnitude are remaining in the line based on the results of the Ultrascan CD tool run. The detection threshold capability is stated by the manufacturer to be 0.04 inch in depth and 2.36 inches in length. Therefore, Table 2 predicts the time to failure of a flaw of this magnitude, assuming it could exist anywhere in the line.

The results in Table 2 show that a 0.04-inch, 2.36-inch-long flaw has the shortest predicted fatigue life at the Cass Lake Discharge. A time to failure of 63.6 years was calculated using the 2004 Quarter 2 pressure data. Using the pressure cycles used in the June 2003 analysis, a flaw of this size is predicted to grow to failure in 13.2 years. The changes in the cyclic behavior of Line 3 occurring since the Cohasset failure have increased the fatigue life by slightly over 50 years.

Based on the results of our quarterly analyses and the results of the Ultrascan CD in-line inspection, it would not be expected that any flaw remains in the line that would fail due to pressure-cycle-induced fatigue any time within 32 years of the date of the previous hydrostatic test. This includes a factor of safety of 2 applied to the fatigue life calculated at the Cass Lake discharge.

Subsequent quarterly analyses will be conducted to monitor the pressure cycles. As the current calculations show a reduction in the aggressiveness of the pressure cycles this translates into an increase in the fatigue life of any flaws that may be present in the line.

If you have any questions or comments, please call me.

Sincerely,

Carolyn E. Kol

Carolyn E. Kolovich
Engineer II

CEK:gw

Table 1. Comparison of Times to Failure of Benchmark Cycles to Actual Operating Cycles

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.375 WT	Very Aggressive	1.3	1.1	1.1	1.0	1.1	1.2	1.6	2.8	5.8
	Clearbrook 2000 Q1	***1.6***	***1.5***	***1.4***	***1.4***	***1.5***	***1.8***	***2.8***	***5.3***	***11.4***
	Aggressive	5.0	4.4	4.1	4.1	4.2	4.8	6.6	11.4	23.4
	Moderate	12.7	11.1	10.4	10.4	10.6	12.1	16.9	28.9	59.9
	Clearbrook 2004 Q2	***13.2***	***12.1***	***11.6***	***11.2***	***11.5***	***13.7***	***20.6***	***38.0***	***80.4***
	Clearbrook 2004 Q1	***16.3***	***15.0***	***15.0***	***14.3***	***14.3***	***17.0***	***25.8***	***47.2***	***99.6***
	Light	28.9	25.1	23.9	23.6	24.2	27.7	38.3	65.9	136.3

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.344 WT	***Deer River 2000 Q1***	***1.0***	***1.0***	***1.0***	***1.0***	***1.1***	***1.5***	***2.8***	***5.7***	***12.5***
	Very Aggressive	1.2	1.1	1.0	0.9	1.0	1.1	1.6	2.8	5.9
	Aggressive	4.8	4.1	3.9	3.9	4.1	4.7	6.6	11.4	23.6
	Deer River 2004 Q2	***7.5***	***7.1***	***6.6***	***6.4***	***6.9***	***9.5***	***16.6***	***33.5***	***73.5***
	Deer River 2004 Q1	***10.0***	***9.5***	***9.0***	***8.6***	***9.1***	***12.5***	***21.8***	***43.6***	***95.2***
	Moderate	12.1	10.4	10.1	10.0	10.4	11.9	16.7	29.0	60.4
	Light	27.4	23.9	22.9	22.7	23.6	27.1	37.9	66.0	137.4

		Time to Failure for Incremental Flaw Depths								
		90%	80%	70%	60%	50%	40%	30%	20%	10%
X52 0.281 WT	Very Aggressive	1.1	0.9	0.9	0.9	0.9	1.1	1.6	2.8	5.9
	Floodwood 2000 Q1	***1.6***	***1.5***	***1.5***	***1.5***	***1.6***	***1.9***	***2.9***	***5.3***	***11.4***
	Cass Lake 2000 Q1	***1.9***	***1.7***	***1.6***	***1.6***	***1.7***	***2.0***	***2.9***	***5.1***	***10.8***
	Aggressive	4.1	3.8	3.6	3.6	3.9	4.4	6.4	11.4	24.1
	Cass Lake 2004 Q2	***9.6***	***8.6***	***8.5***	***8.5***	***8.7***	***10.2***	***14.3***	***25.3***	***53.1***
	Moderate	10.5	9.5	9.1	9.2	9.6	11.4	16.4	29.1	61.4
	Cass Lake 2004 Q1	***11.5***	***10.0***	***10.0***	***10.0***	***10.5***	***12.0***	***17.5***	***30.4***	***63.8***
	Floodwood 2004 Q2	***17.2***	***16.1***	***15.6***	***15.4***	***15.7***	***18.3***	***26.2***	***47.0***	***99.1***
	Light	23.9	21.6	20.8	20.9	21.9	25.9	37.1	66.0	139.6
	Floodwood 2004 Q1	***24.4***	***22.4***	***21.9***	***21.9***	***22.4***	***25.9***	***36.9***	***66.3***	***139.1***

Table 2. Times to Failure of a Flaw Given by the Detection Threshold Capability of the Ultrascan CD Tool

Location	Comment	Scale Factor	2004 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2004 Quarter 2 Time to Failure of 0.04-in deep, 2.36-in long Defect, years	2000 Quarter 1 Time to Failure of 0.04-in deep, 2.36-in long Defect, years
Clearbrook	Clearbrook discharge pressures	1	161.4	130.3	19.4
MP 912.9	Transition to 0.344-inch WT	0.93	145.1	117.2	23.2
MP 917.5	Transition to 0.312-inch WT	0.81	146.4	118.2	32.4
MP 925.8	Transition to 0.281-inch WT	0.62	194.3	157.2	61.3
Cass Lake	Cass Lake discharge pressures	1	77.3	63.6	13.2
Deer River	Deer River discharge pressures	1	145.6	113.1	21.3
MP 999.9	Transition to 0.312-inch WT	0.92	128.8	100.0	26.3
MP 1007.2	Transition to 0.281-inch WT	0.77	138.6	107.8	40.5
Floodwood	Floodwood discharge pressures	1	165.5	117.8	14.3

(81)

3-2002-5011

Call to Ivan Huntoon on 7/14/04.

Mark Willoughby, Enbridge, called Wednesday, 7/14/04 at 11:00 a.m.

He reported information to me in regard to flange leak in deadleg at Deer River Station. They are required to report any leaks involving Line 3 to us by our CAO on Line 3.

The leak resulted in a small quantity of crude oil on ground. It was all contained on Pump Station site in are of the Suction valve for Line 3.

They found a weeping flange on a spoolpiece in mainline. It was on a deadleg associated with Line 3 suction valve piping. The spoolpiece had been installed at some point to replace a check valve that previously existed there.

MNOPS was on site to investigate. (Central Region has e-mails from Dan Munthe, MNOPS, informing us of the activity.)

The deadleg was scheduled for removal in October 2004 as part of Enbridge's program to eliminate leaks in non-flowing sections of pipe.

Mark will send us a letter with leak and program information for our records.

Ivan Huntoon IH

Enbridge Pipelines (Lakehead) L.L.C.
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David A. Weir
U.S. Compliance & Risk Management
Tel 403 420 8145
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david.weir@enbridge.com

ENBRIDGE™

December 30, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

The Enbridge Line 3 Risk Management Plan outlining our proposed approach for the analysis of risk is attached for your review. Timelines in this plan are consistent with the capital and operating budget processes described in the Enbridge High Consequence Area Management Plan, running from January through June, 2004. Through these processes, the risk assessment results outlined in the Line 3 Risk Management Plan will be examined in detail and select risk control and mitigation activities and projects will be proposed and brought forth for approval. An Office of Pipeline Safety (OPS) review of the Line 3 risk control and mitigation projects would best be scheduled for July, 2004.

Enbridge welcomes your comments regarding our risk assessment strategy and will continue to work with the OPS through the upcoming risk assessment processes.

Operational Risk Management (ORM) is available for questions and/or comments regarding the Line 3 Risk Assessment Plan. If beneficial, ORM is also available to meet in person to discuss the results and planned next steps.

Please let me know if Enbridge can be of further service. Should you have any questions regarding this information, please contact me at (403) 420-8145.

Sincerely,

David Weir

David Weir

Attachment

Enbridge Line 3 Risk Management Plan

December, 2003

Line 3 Risk Management Plan

Introduction

The Enbridge Energy Partners Line 3 Risk Management Plan has been developed in response to the September 5th, 2003 request for the same by the Office of Pipeline Safety (re: CPF No. 3-2002-5017H). The Plan leverages and builds on Operational and local Region knowledge, line integrity data and additional information which is comprehensively consolidated and integrated within the mainline risk assessment model. Concerns associated with operational pipeline hazards are managed by distinct functional departments (Safety, Environment, Integrity, Operations, Legal, etc.). The Line 3 Risk Management Plan integrates available information, enhances knowledge sharing between the functional departments, and expands the company's ability to systematically define and address operational risks.

Line 3 consists of approximately 325 miles of 34 inch pipeline extending from the USA/Canada border near Gretna, Manitoba to Superior, Wisconsin.

The Line 3 Risk Management Plan is an extension of the data and processes described in the Enbridge U.S. Mainline High Consequence Area (HCA) Management Plan.

Risk Management of Pipeline Integrity Hazards

Within the context of overall risk evaluation and management, those hazards specifically associated with duty-related deterioration of the pipeline system are largely managed by the Pipeline Integrity Department. These hazards include:

- Metal loss (corrosion)
- Pipe deformation such as denting.
- Cracking related to steel manufacturing or forming processes.
- Cracking related to exposure to the operating or natural environments.
- A combination of the above items.

Risk control for the hazards listed above relies on the integration and assessment of pipeline data and Operational knowledge both within and outside the Enbridge mainline risk assessment model. Based on failure history, in-line inspection (ILI) results, excavations/direct assessment, susceptibility studies, models, and data trending, specific hazards that affect any given pipeline segment are identified. Data is collected and analyzed to characterize these hazards, and programs are developed, documented, and implemented to ensure timely repair of defects in accordance with established tolerances, specifications, and procedures. Programs are continuously improved through ongoing data analysis and trending.

In order to manage scientific uncertainties (risks) additional risk-based considerations are integrated into the fitness for purpose engineering approach. This includes integration of consequence information to influence ILI schedules and use of spatially displayed integrity data within the mainline risk model. As the defect management approach generally considers trap-to-trap segments, the mainline risk assessment results are also examined from a whole-risk and factor-specific risk perspective identifying both the high-risk pipe segments and localized factor-specific high-risk areas designated for greater analysis.

Mainline Risk Assessment Model

Assessment and mitigation of risk have always been central to Enbridge pipeline operations. The Enbridge Mainline Risk Assessment Program was initiated to develop a more comprehensive and integrated approach to risk identification, assessment, control and prioritization which builds upon existing integrity and risk management approaches currently in use. While most components of Enbridge pipeline risk management have long been in place, the integration of both probability and consequence factors within a model provides a convenient means for an enhanced and comprehensive assessment of the relative risks of the mainline pipeline systems.

The Enbridge Mainline Risk Assessment model comprehensively evaluates the range of hazards and potential consequences. The model has been customized to include those likelihood and consequence conditions applicable to the Enbridge liquid pipeline system. This model is applied equally to all Enbridge liquid pipelines including Line 3

The implementation of the mainline risk assessment has involved active participation from each Enbridge Region. Roles, responsibilities and expectations on the development, implementation and use of the risk assessment results have been clearly laid out.

Data for inclusion in the mainline risk assessment model has been actively solicited from a number of departments including Superior Region Operations, U.S. Environment, Pipeline Integrity, Right-of-Way Management, Shipper Services, Engineering and Drafting, Pipeline Control, and Control Center Operations.

A comprehensive description of the Enbridge Mainline Risk Assessment Program is provided in the U.S. Mainline HCA Management Plan, Tab 4. An overview of the mainline risk assessment model is provided in Appendix A.

High Consequence Areas

The Line 3 Risk Assessment incorporates high consequence areas into the assessment of consequence as follows:

Direct High Consequence Areas	Pipe sections which are physically located within or tangent to an HCA.
Transport High Consequence Areas	Pipe sections which through a transport mechanism (overland flow, flow of crude oil within or on water, or spray) may impact an HCA.
Overlap High Consequence Areas	Pipe sections which may impact multiple instances of the same type of HCA. For example, a section of pipe which impacts two or more distinct environmentally sensitive areas.

The Overlap HCA type is an enhancement to the risk assessment model demonstrated to the OPS in May/June of this year. This change has resulted in an increase in the number of identified Line 3 HCA Segments.

Further information regarding HCA identification or integration of HCA data with the mainline risk assessment is provided in the Enbridge HCA Management Plan.

Project Identification and Prioritization

The mainline risk assessment model is a decision support tool which assists in the identification and prioritization of projects and activities designed to control or mitigate risk. The mainline risk assessment is both supplementary and complementary to existing operational risk management processes and activities.

By understanding the risk drivers in both overall and discrete sections, Operations personnel can take the risk assessment results, line integrity data and their own expertise to propose and pursue the optimum combination of risk control or mitigation activities.

The mainline risk assessment model also generates relative risk rankings based on the likelihood and consequence conditions for a given section of pipe. Through these rankings it is possible to identify and target areas for risk control and mitigation consideration. In addition, projects can be prioritized using the relative risk scores generated for each pipeline section.

Data Integration and Presentation

The mainline risk assessment facilitates the integration of data from many existing Enbridge sources and provides a forum for proactive examination of the risk drivers either in discrete pipe sections or for Line 3 as a whole. This examination combined with Operational, Regional, Engineering, and integrity knowledge creates a powerful tool for trending and identification of risk drivers.

Factor Specific and Whole Risk Analysis

The mainline risk assessment results are examined both holistically (total risk score) and by each factor contributing to this score (likelihood factors include corrosion, third party, ground movement, design and materials, and systems operations; consequence factors include impacts on population, environment and business). Through this process both the high risk pipe sections and factor specific high risk areas are examined and/or addressed.

The next nine sections of this plan analyze the risk assessment results; first from a factor by factor basis and then lastly, on a whole risk basis. Detailed risk assessment results have been generated in both HCA Segments and 1000 ft sections. Thus it is possible to examine the risk drivers from both an HCA and total system perspective. The data and risk result analysis in the following sections concentrate on the 1000 ft risk assessment results.

Graphical representations presented throughout this document are compressed to fit within this report. Actual graphical data needed for examination and analysis by Region staff are expanded to present the data in a manner allowing company personnel to identify areas of concern.

Risk Assessment Sections

Two separate methods have been used to section Line 3 in the mainline risk assessment analysis.

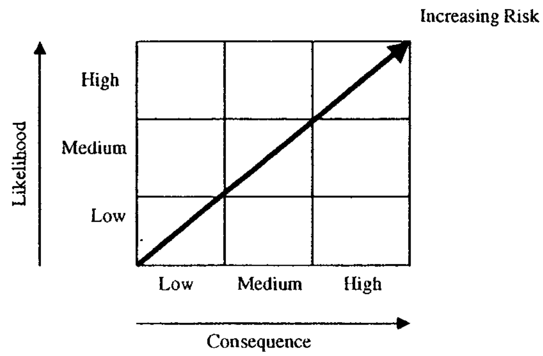
Method A – By High Consequence Areas	To assess the risk in HCA segments, the risk assessment is performed on pipe sections based on the location of the HCAs.
Method B – In 1000 Ft Sections	The risk assessment is performed in standard length sections of 1000 ft. This length was selected by Enbridge subject matter experts as being appropriate for Enbridge.

For each method, the worst case risk scores for each variable are assigned to each section being assessed. Thus, for example, if a given risk assessment section has both Low and High Construction Activity within the section, then the worst case (i.e. High Construction Activity) is used in the risk results for the entire section.

For variables where the data value is not known, the worst case condition is assigned as default.

Risk Ranking Matrix

A risk ranking matrix is used as a gross indicator for identifying those pipe sections with high factor specific or whole risk scores. Further analysis is required to determine the actual risk drivers. A risk ranking matrix takes the total likelihood or likelihood factor score and compares it against total consequence (or consequence factor score) on a section by section basis. Risk increases diagonally from the lower left to the upper right as illustrated below.



Risk Profile

In a risk profile, data is presented graphically in milepost or feet stationing order. The higher the bar, the greater is the risk being evaluated.

DETAILED FACTOR-SPECIFIC RISK ANALYSES

Corrosion

Enbridge corrosion risk management is built around information and knowledge collated through 50+ years of operations including over thirty years of in-line inspection. As outlined in the Enbridge HCA Management Plan and reviewed in detail during the OPS Comprehensive HCA audit (May/June 2003), corrosion risk management on Line 3 is based on a fitness-for-purpose or "defect management" approach. As such, integrity risk management programs are designed and implemented to assess and address, in a timely manner, the risk associated with each defect that exceeds Enbridge tolerances. In general, corrosion integrity risk is assessed and managed as follows:

- Likelihood of corrosion failure is managed through fitness-for-purpose engineering
- Consequence aspects of corrosion risk are evaluated through the mainline Risk Assessment Model

- Corrosion risk for trap-to-trap segments is defined by combining likelihood and consequence aspects to establish revalidation intervals for corrosion assessment & mitigation
- Corrosion risk is integrated into the Mainline Risk Assessment model using an Integrity Corrosion Factor and consideration of residual (after repair) defect density/severity.
- The Mainline Risk Assessment model provides spatial illustration of corrosion features to facilitate identification of localized corrosion mitigation opportunities

Fitness-for-Purpose Engineering

This corrosion defect management approach is applied in distinct trap-to-trap segments and is based on the application of in-line inspection technology. Since it's initial Magnetic Flux Leakage ILI in 1979, the two Line 3 segments (Gretna to Clearbrook and Clearbrook to Superior) have each been assessed an additional four times using high-resolution ILI tools. In accordance with the Enbridge Baseline Assessment, the next scheduled corrosion ILI for both segments is 2006.

Corrosion defects identified during these in-line inspections are repaired in accordance with company, industry and regulatory requirements. For other defects not compromising these tolerances, continued deterioration is arrested or monitoring programs are set in place to address the defects in a timely manner. The aim of this risk management program is to identify and correct low-level pipeline damage and deterioration before major repairs are needed.

Integral to this corrosion risk management approach is the establishment of intervals used for reassessment of defects that did not compromise tolerances during the prior ILI run. In order to manage uncertainty or risk associated with derivation of revalidation intervals, Enbridge has employed progressively more sophisticated approaches to assist with the understanding of defect growth rates. This includes pit-to-pit matching from sequential in-line inspection runs and quantitative analysis of corrosion growth using advanced statistical analysis.

Consequence Considerations and Integration

Analysis of whole risk must also consider consequence. As such, consequence assessments from the mainline risk assessment model are used as a means of addressing variable site conditions across Line 3 and to enhance probabilistic calculation of the revalidation interval.

On its own, the revalidation interval defined through fitness-for-purpose engineering includes inherent conservatism and represents the best determination by Enbridge as to when any given segment should be revalidated. As indicated in the Enbridge HCA Management Plan, the Line 3 segment between Gretna and Clearbrook has a consequence ranking of 20 (of the 30 trap-to-trap segments on the Enbridge USA system). In contrast, the Clearbrook to Superior segment has a consequence ranking of 10. In consideration of this relatively higher consequence ranking, and as part of the overall Enbridge corrosion risk mitigation strategy, the revalidation interval in the Clearbrook to Superior segment of Line 3 has been reduced by one year from the interval derived through probabilistic fitness-for-purpose calculations.

Integration into the Mainline Risk Assessment Model

The initial representation is tied directly to the preceding discussion, whereby increased corrosion risk is linked to the revalidation interval through a dimensionless factor called the Integrity Corrosion Factor (ICF). The ICF represents the outcome of the engineering analysis approach to defining corrosion occurrence. If the ICF values are low, this indicates that the pipe segment has been revalidated recently, the concerns associated with a corrosion leak are low, and that integrity monitoring or mitigative actions will not be conducted in the near term. Conversely, if the ICF is high, it can be expected that monitoring or mitigative actions will be conducted in the near term and likelihood of a corrosion leak are comparatively higher.

ICF = (present yr – year last inspected) / (revalidation interval)

Corrosion likelihood is further integrated into the mainline risk assessment model by inclusion of after-repair defect density and severity (rupture pressure ratio or RPR and depth), and corrosion growth (described above as the Integrity Corrosion Factor – ICF).

Spatial Illustration of Corrosion Data

The Mainline Risk Assessment model also provides a spatial illustration of corrosion distribution on the pipeline. This spatial display of data allows both the Pipeline Integrity Department and Operations personnel to review specific areas of relatively higher corrosion density and severity in order to evaluate alternative mitigative actions or prepare enhanced mitigation programs to address specific drivers. (For example, if corrosion growth rate derivation for an entire trap-to-trap segment is being driven by a small area of comparatively higher corrosion density and/or growth, then alternative corrosion mitigations options such as pipe replacement can be proposed by either Operations or Pipeline Integrity.)

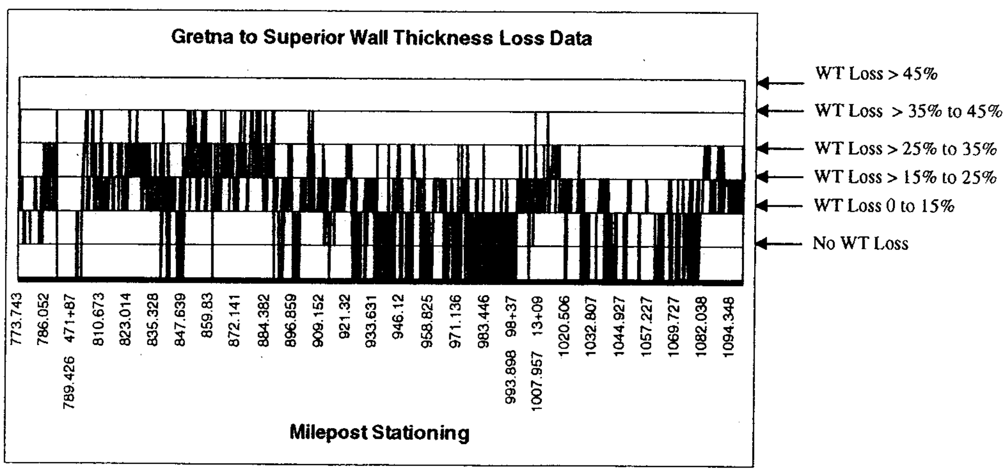
Mainline Risk Assessment Model Results

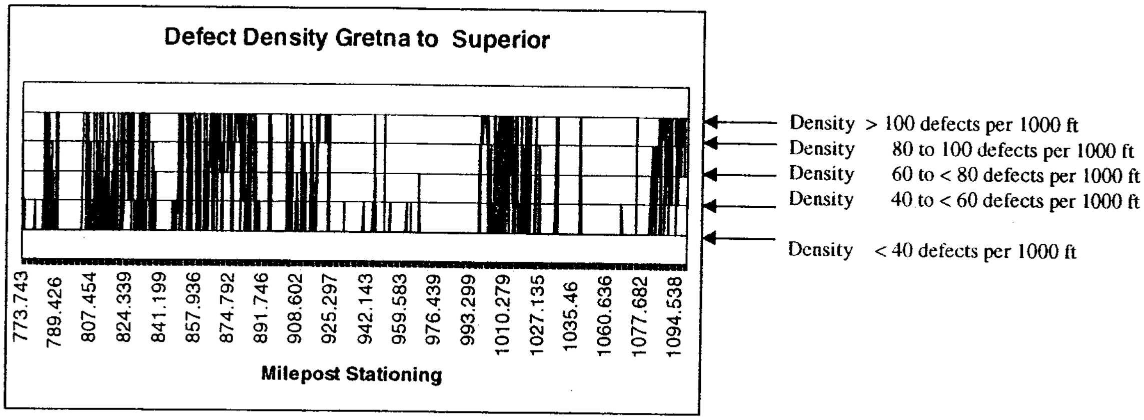
A review of the mainline risk assessment corrosion results on a variable by variable basis yields the following:

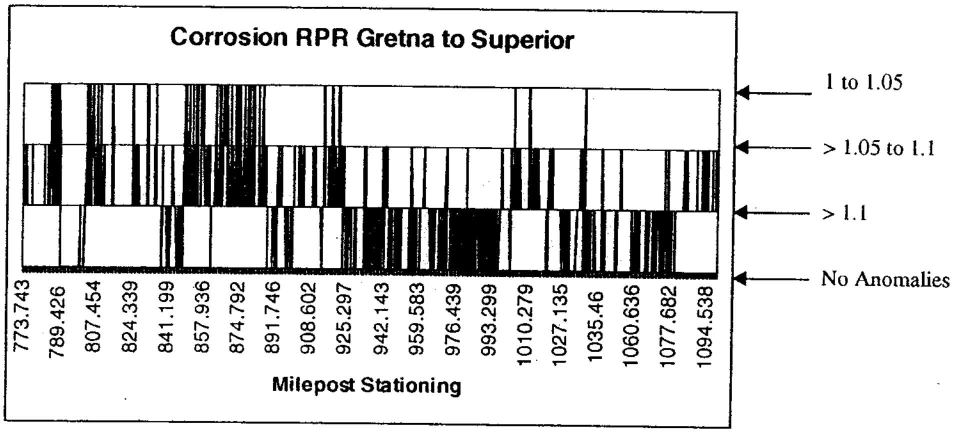
Corrosion Variable	Overview of Line 3 Corrosion Variable Data
Defect Wall Thickness Loss	Variable. 2.5% of the 1000 ft sections with wall loss exceeding 45%.
Defect Density	Variable. 17.8% of the one thousand foot sections with density exceeding 100 defects.
Defect RPR	Variable, none exceeding Enbridge tolerance.
Defect Growth (Integrity Corrosion Factor)	0.20 to < 0.30 (constant for Line 3)

As discussed above, the spatial display of residual (after-repair) ILI data enables Pipeline Integrity and Operations personnel to examine the corrosion risk drivers in more select or discrete pipe section lengths. The following diagrams display the defect density and severity (depth and RPR) results in profile format for Line 3 from Gretna to Superior. Using such tools it is possible to identify areas for more focused study and consideration.

Review of Individual Corrosion Risk Drivers







Third Party

Current Risk Control or Mitigation Practices an Activities

Current activities and/or processes to mitigate or control the risks posed by third party activity include:

One Call System

All of the states in which the Enbridge liquid pipelines operate, including both North Dakota and Minnesota have one-call systems. More information on the one-call system and tracking statistics can be obtained from the U.S. Desktop and Field Services Team lead.

Public Awareness Program

The Enbridge Public Awareness Program is described in the Operations and Maintenance Manual Book 1: General Reference Manual.

Aerial Patrol

Enbridge conducts regular aerial inspections of its entire right-of-way and the land adjacent to the right-of-way for abnormal surface conditions. More details, including the frequency of aerial patrols, are described in the Operating and Maintenance Procedures Book 3: Pipeline Facilities, 03-02-01 Right-of-way Inspections.

ROW Clearing and Line Marking

The annual Superior Region Operating Cost Budget includes funds for right-of-way clearing. Line Marking signs are replaced as needed by Pipeline Maintenance crews usually as a result of third party phone calls, right-of-way patrol, or during right-of-way maintenance and clearing. Additional information regarding right-of-way clearing and line marking can be found in the Operations and Maintenance procedures Manual, Book 3, Tab 3 – ROW Maintenance.

Depth of Cover Surveys

Funds have been earmarked in the 2004 Superior Operating Cost Budget to begin an anticipated five year depth of cover survey program which will update the current depth-of-cover data from surveys conducted in the early 1990's.

Contractor Informational Meetings

Prior to performing work on or near the pipeline right-of-way, Contractors attend an informational meeting hosted by Enbridge. Further information on these meetings is included in the Operations and Maintenance Procedures Manual Book 1, Tab 4 – Public Awareness Program.

Geometry In-line Inspection

In general, geometrical deformities such as dents and buckling have not been a key hazard mechanism on Line 3 between Gretna, MB, and Superior, WI. Notwithstanding this historical data trend, Enbridge conducts a geometry inspection using deformation/inertial tools during every corrosion or cracking ILI run.

By matching these geometry assessment ILI intervals with corrosion ILI intervals, consequence considerations derived from the Mainline Risk Model are inherently integrated into the deformation re-assessment schedule.

Risk mitigation strategies with regards to pipe deformation as a result of third party damage are largely managed by Regional Operations personnel. For areas where deformations exist or the Enbridge risk model suggest high likelihood of third party damage, the risk mitigation focus is on prevention with application of mitigative approaches such as additional signage, additional right of way clearing, installation of tape or concrete above the pipelines, increased landowner visitation, planning of community pipeline information sessions, etc. In the event that Operations personnel believe that incremental in-line inspection would also serve as a significant risk reduction measure, the Supervisor of Integrity Programs will be contacted and additional geometry tool assessments will be coordinated between those intervals normally conducted as part of metal loss evaluation.

The historical pairing of metal loss/crack detection and geometry tools has yielded positive results for Enbridge with incidents of third party damage on the Enbridge system remaining substantially lower than industry norms.

Mitigation of geometry defects identified through in-line inspection involves pipe repair in accordance with specifications outlined in the HCA Rule and/or Enbridge documents. (For details see *Excavation Guideline Document, OM&P Book 3* and the Mitigation section the *Enbridge HCA Management Plan* document).

Risk Assessment Results

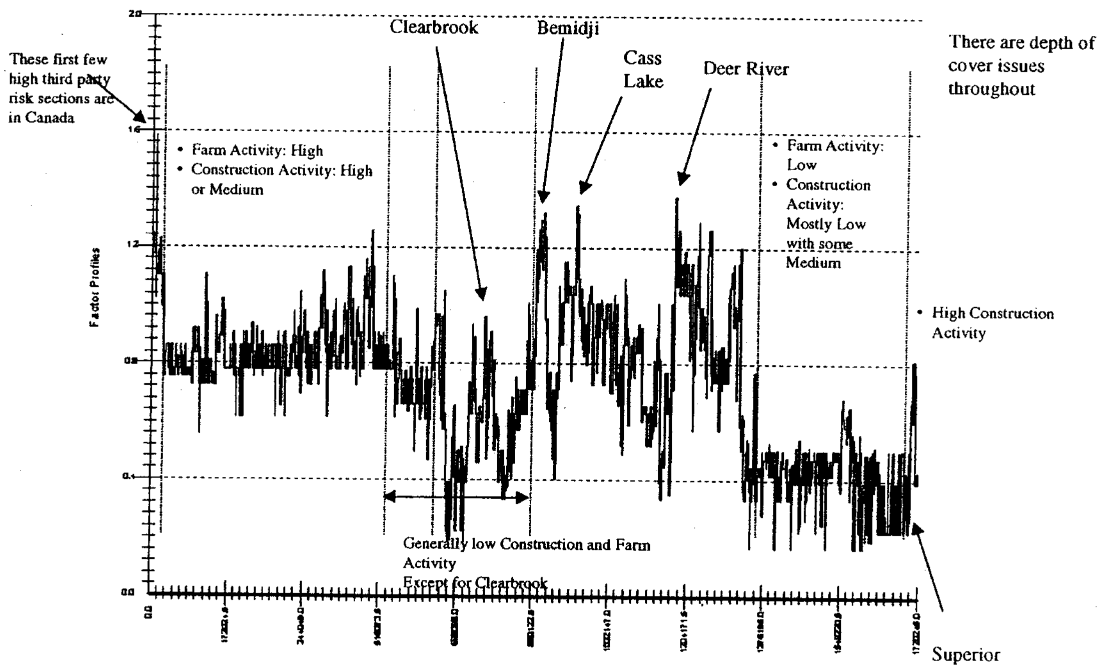
A review of the mainline risk assessment third party results by variable yields the following:

Third Party Variable	Overview of Line 3 Third Party Variable Data
Construction Activity	Variable
Farm Activity	Variable
Crossing Exposure	Variable
Third Party Leak History	No Third Party Leaks
One Call Effectiveness	High
Patrol Frequency	Medium
Public Education	Excellent or Good
Depth of Cover	Variable.
Age of Caliper / Geometry Tool Runs	Less than 2 years.
Line Marking	Excellent or Good
Right-of-way Condition	Variable
Dent Defect and Orientation	Forty-one dents, most on top of pipe.

Overview of Third Party Risk

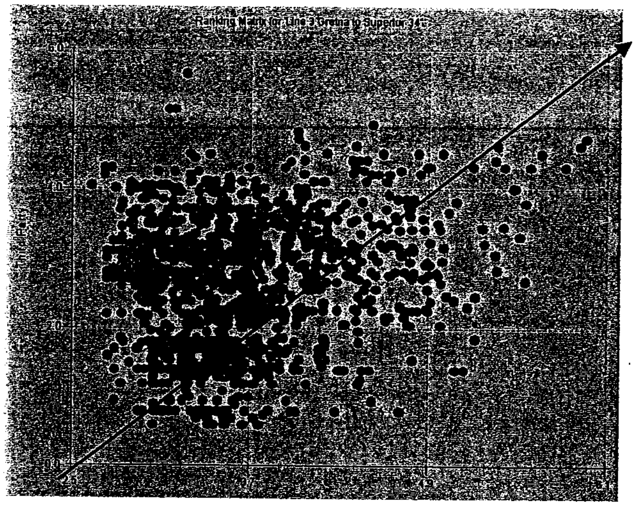
The diagram below illustrates the third party risk profile from Gretna to Superior. Peaks in the third party data correspond to areas with significant farm activity or in populated areas where there is a larger presence of foreign crossings, construction activity and encroached right-of-way.

Line 3 Third Party Risk Profile



Top Risk Areas

The top ranked Third Party areas (compared against consequence) are those in the uppermost right corner of the risk matrix below. The third party details for the top twenty pipe sections are provided on the next page.



Third Party Drivers Top 20 Third Party Risk Sections

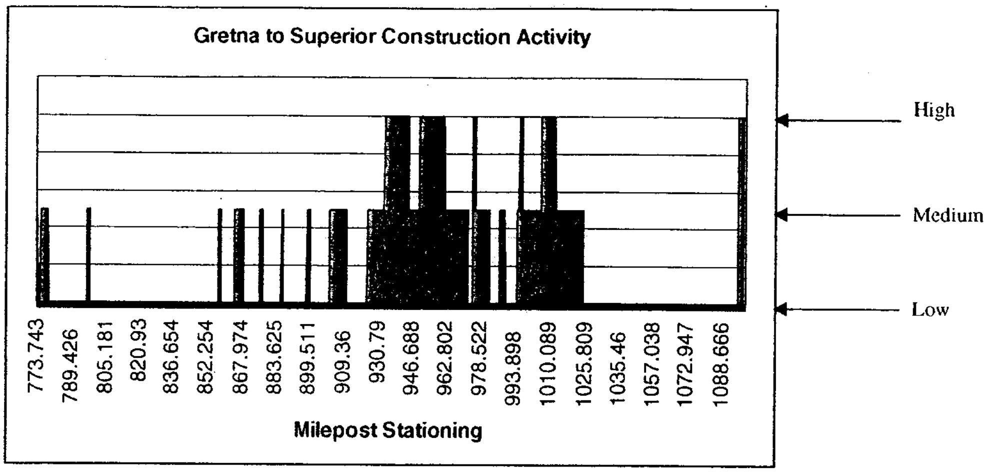
Section	Start MP	End MP	Construc Activity	Farm Activity	One Call Effect	Patrol Freq	Public Education	Depth of Cover	Crossing Exposure	Line Marking	ROW Condition	Leak History	Age of Caliper Survey	Dent / Gouge	1000 Ft Section Risk Rank
Clearbrook to Cass Lake	938.934	939.123	High	Low	High	Medium	Excellent	> 0 to 2 Ft	10 to < 30 %	Good	Encroached	0 Leaks	< 2 Years	None	9
Clearbrook to Cass Lake	937.608	937.797	High	Low	High	Medium	Excellent	> 0 to 2 Ft	10 to < 30 %	Good	Encroached	0 Leaks	< 2 Years	None	18
Clearbrook to Cass Lake	938.555	938.744	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	21
Clearbrook to Cass Lake	938.744	938.934	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	12
Clearbrook to Cass Lake	938.176	938.366	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	95
Clearbrook to Cass Lake	939.123	939.313	High	Low	High	Medium	Excellent	<= 0 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	30
Clearbrook to Cass Lake	937.419	937.608	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	119
Clearbrook to Cass Lake	939.881	940.07	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	74
Clearbrook to Cass Lake	939.502	939.691	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	144
Deer River to Floodwood	1009.521	1009.71	High	Low	High	Medium	Good	> 0 to 2 Ft	< 5 %	Good	Small Overgrowth	0 Leaks	< 2 Years	None	2
Clearbrook to Cass Lake	937.797	937.987	High	Low	High	Medium	Excellent	> 2 to 3 Ft	> 60 %	Good	Encroached	0 Leaks	< 2 Years	None	192
Cass Lake to Deer River	993.898 48+37	993.898 58+37	High	Low	High	Medium	Good	> 0 to 2 Ft	10 to < 30 %	Good	Encroached	0 Leaks	< 2 Years	None	283
Clearbrook to Cass Lake	938.366	938.555	High	Low	High	Medium	Excellent	> 2 to 3 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	153
Deer River to Floodwood	993.898 445+00	993.898 455+00	Medium	Low	High	Medium	Good	> 0 to 2 Ft	< 5 %	Good	Small Overgrowth	0 Leaks	< 2 Years	None	8
Deer River to Floodwood	1009.9	1010.089	High	Low	High	Medium	Good	> 0 to 2 Ft	< 5 %	Good	Small Overgrowth	0 Leaks	< 2 Years	None	1
Clearbrook to Cass Lake	939.313	939.502	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	263
Clearbrook to Cass Lake	937.229	937.419	High	Low	High	Medium	Excellent	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	269
Cass Lake to Deer River	951.484 201+30	951.484 211+30	High	Low	High	Medium	Good	<= 0 Ft	30 to 60 %	Excellent	Clear and Obvious	0 Leaks	< 2 Years	None	29
Deer River to Floodwood	1022.589	1022.779	Medium	Low	High	Medium	Good	> 0 to 2 Ft	< 5 %	Good	Encroached	0 Leaks	< 2 Years	None	99
Deer River to Floodwood	1009.142	1009.332	High	Low	High	Medium	Good	> 2 to 3 Ft	< 5 %	Good	Small Overgrowth	0 Leaks	< 2 Years	None	17

The total risk score for the 1000 ft section is provided as the rightmost column of the table for comparison. Those sections of pipe with high construction activity, depth of cover issues, and room for improvement in both line marking and right-of-way condition rank the highest.

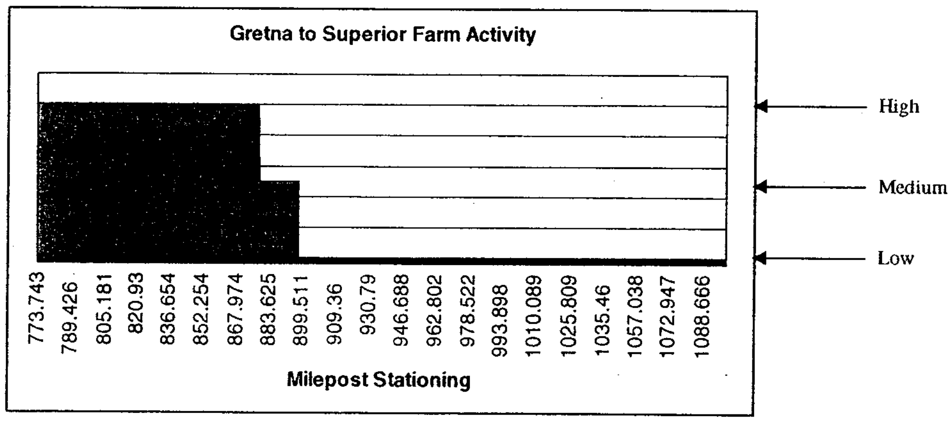
Review of Individual Risk Drivers

An examination of the Line 3 Third Party risk drivers is provided below. An examination of the Third Party Data as it applies to the Line 3 HCA Segments is provided in Appendix B

Construction Activity



Farm Activity

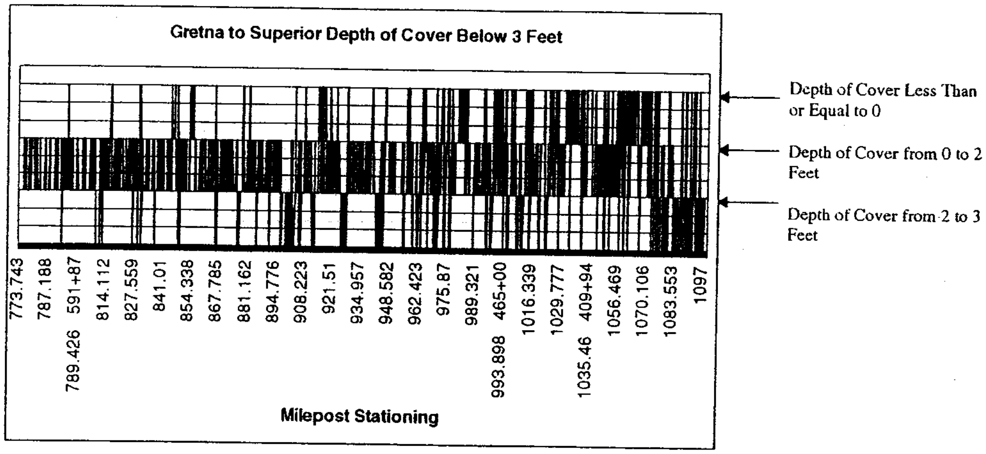


Public Education

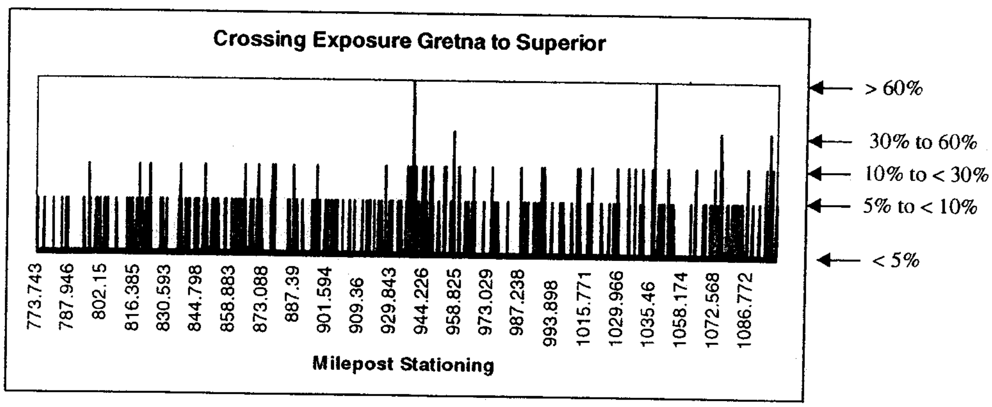
For Gretna to just south of Clearbrook, Public Education on Line 3 is valued as Excellent. For the remainder of Line 3, Public Education is either Good or Excellent. Those pipe sections where Public Education is evaluated as good are:

Station to Station Section	MP Start	MP End
Clearbrook to Cass Lake	909.36 239+00	920.184
Cass Lake to Deer River	951.484 76+80	951.484 321+30
Deer River to Floodwood	989.89	992.162
Floodwood to Superior	993.867	1025.01

Depth of Cover



Crossing Exposure (a measure of the number of 3rd party Crossings for a given section of pipe)



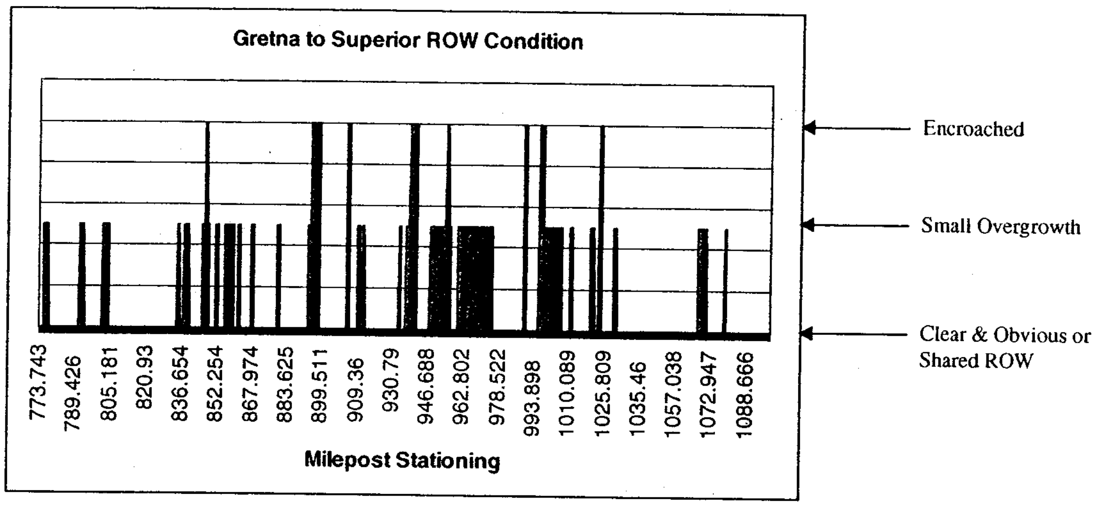
Line Marking

From Gretna to Superior the majority of Line Marking is excellent. There are several sections where the Line Marking has been graded as good which are listed below:

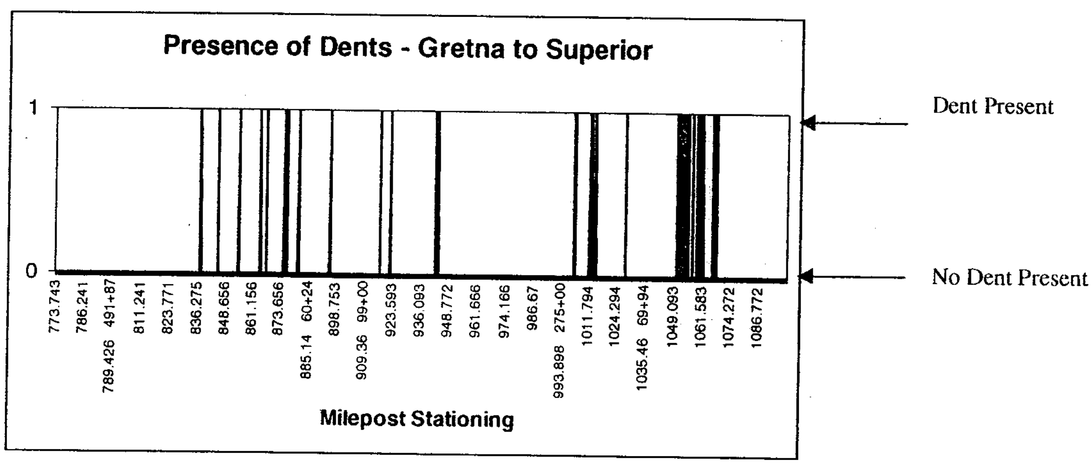
Station to Station Section	MP Start	MP End
Plummer to Clearbrook	895.912	897.049
Plummer to Clearbrook	900.836	902.162
Clearbrook to Cass Lake	909.36 349+00	918.10
Clearbrook to Cass Lake	935.904	940.99 1+44
Clearbrook to Cass Lake	945.931	951.044
Near Cass Lake	951.484 6+80	951.484 141+30
Cass Lake to Deer River	951.484 341+30	989.132
Cass Lake to Deer River	990.836	993.898 8+37
Deer River to Floodwood	993.898 48+37	993.898 465+00
Deer River to Floodwood	993.898 505+00	1005.364
Deer River to Floodwood	1008.953	1010.089
Deer River to Floodwood	1017.854	1020.127
Deer River to Floodwood	1021.832	1023.157
Deer River to Floodwood	1028.83	1030.155

Right of Way Condition

The right of way condition for several sections of pipe from Gretna to Superior is encroached or has small overgrowth as illustrated in the diagram below. Encroached right of way condition is associated with areas of higher population.



Dent Defects



Ground Movement

Current Risk Control or Mitigation Practices and Activities

Current activities and/or processes to mitigate or control the risks posed by third party activity include:

Pipe Weights and Hold Downs

Current guidelines and procedures for the placement of pipe weights / hold downs are contained in the Engineering Standards and Engineering Specification documents.

Ground Movement Monitoring

Aerial patrol is the primary monitor of potential ground movement, however geometry in-line inspections are run when necessary.

River Crossing Survey (Navigable Waterways)

River crossing surveys are conducted every five years. See Operations, Maintenance and Procedures Manual, Book 3 Section 3.

Areas of Concern

Areas of ground movement concern are identified by third parties, field crews working in the area, or aerial patrol. Such areas are evaluated on a case-by-case basis and corrective action (stabilization) is undertaken if necessary.

Risk Assessment Results

On a high level, the review of the Ground Movement Variable data yields:

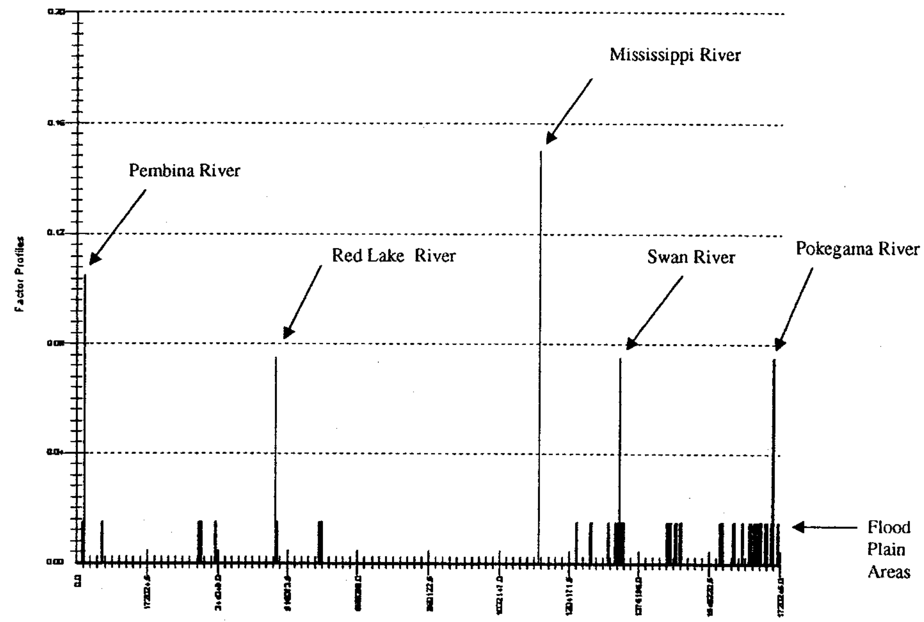
Ground Movement Variable	**Overview of Line 3 Ground Movement Variable Data**
Presence of Major Water Crossing	Four identified.
Presence of Seismic Fault Line	None present.
High Ground Instability	Two sections identified.
Natural / Man-made Seismic Area	None present.
Nearby Mining Operations	None present.
Weights or Hold Downs for Major Water Crossings	All Major Water Crossings have weights and/or hold downs.
Ground Movement Monitoring	Not Required or Not Applicable

An examination of ground movement data as it applies to the Line 3 HCA segments is provided in Appendix C.

Overview of Ground Movement Risks

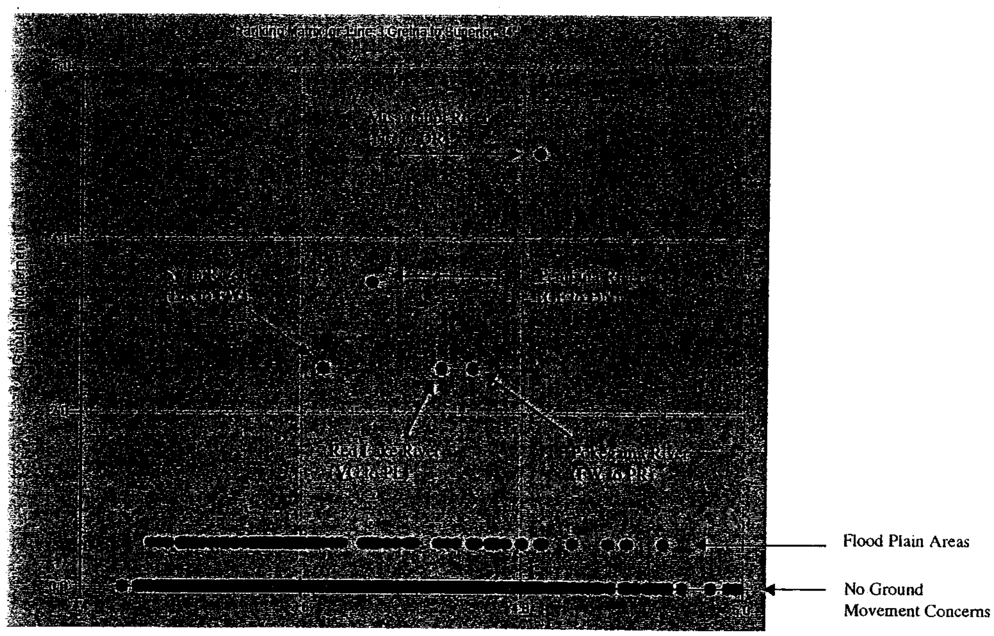
The diagram below illustrates the ground movement risk profile from Gretna to Superior. Peaks in the ground movement data correspond to river crossings as noted.

Ground Movement Risk Profile - Gretna to Superior



Top Risk Areas

The top five Ground Movement areas (compared against consequence) are those identified in the risk matrix below.



Design / Materials

Current Risk Control or Mitigation Practices or Activities

Cracking

As with corrosion, in-line inspection forms the cornerstone of crack risk management on Line 3 between Gretna, Manitoba, and Superior, Wisconsin. The GE/PII Ultrasonic crack detection (CD) tool was run in the Gretna to Clearbrook segment in July 2001, and in the Clearbrook to Superior segment in November 2002.

Crack features identified during these CD tools runs have been repaired in accordance with Enbridge criteria. The Enbridge crack assessment and repair program has been reviewed in detail by the OPS.

Management of crack risk on Line 3 has been further enhanced through fatigue crack growth analyses conducted by Keifner and Associates Inc. (See Enbridge's Line 4 – 34-Inch Return-to-Service Plan - Revised September 30, 2003). Uncertainties (risk) associated with validity of pressure data used during this modeling/analysis are being further managed and minimized through regular monitoring of current pressure data.

In aggregate, risk evaluation including review of results from the in-line inspections, field investigations, metallurgical studies, pressure cycling studies, and reliability assessments indicated that there is negligible likelihood of a long seam failure on Line 3 between Gretna and Superior. Although crack likelihood is negligible throughout, the risk of a crack failure varies across the system based on consequence aspects of the risk equation.

While analysis around likelihood of crack failure occurrence is done largely outside the Mainline Risk Assessment Model, inclusion of crack distribution data provides broader awareness of crack distribution throughout the pipeline and enables consideration of crack distribution in operational decisions.

Stress Corrosion Cracking (SCC)

In addition to cracking that affects the welded seam of the pipe, risks associated with pipe-body or Stress Corrosion Cracking (SCC) on Line 3 are also assessed and managed through in-line inspection. GE/PII Ultrasonic crack detection in-line inspection was run on Line 3 in July 2001 on the Gretna to Clearbrook segment and in November 2002 on the Clearbrook to Superior segment. Both inspections identified SCC features that have been assessed and repaired in accordance with Enbridge criteria. SCC risk analysis and management has been reviewed with the OPS as part of prior information requests.

As an additional risk management tool, Line 3 pressure spectrum data, soils / landscape information and in-line inspection data is being analyzed in consideration of recent Pipeline Research Council International (PRCI) research. Such analysis assists in the prediction of additional SCC occurrence and allows determination of conservative re-validation intervals. As with cracks, inclusion of SCC data provides a broader awareness of SCC distribution throughout the pipeline and enables consideration of SCC distribution in operational decisions.

System Operations

Current Risk Control or Mitigation Practices or Activities

Enbridge Safety Program

Detailed information regarding the Enbridge Safety Program can be found in the Operating & Maintenance Procedures Manual – Book 2.

Drug Testing Program

The Enbridge Drug Testing policy is provided in "e-Source[2]".

Training Programs

Training programs are addressed in the "Operator Qualification and Performance Based Job Tasks" manual.

Control Center Procedure and Training

Edmonton Control Center procedures are written to treat all emergency situations equally. Control Center procedures and training are documented in the Lotus Notes "Procedures" and "Training" databases, respectively. Individual operator qualifications are documented in the "Control Center Operator Qualification" Lotus Notes database.

Computational Pipeline Monitoring System – Mass Balance Leak Detection System

The Mass Balance System (MBS) provides system-wide software based leak detection. Complementing the Mass Balance System, the proprietary Line Pressure Monitoring (LPM) Program minimizes the potential of over-pressuring the pipeline. A more complete description of the MBS and LPM systems is contained in the HCA Management Plan, Tab 8.

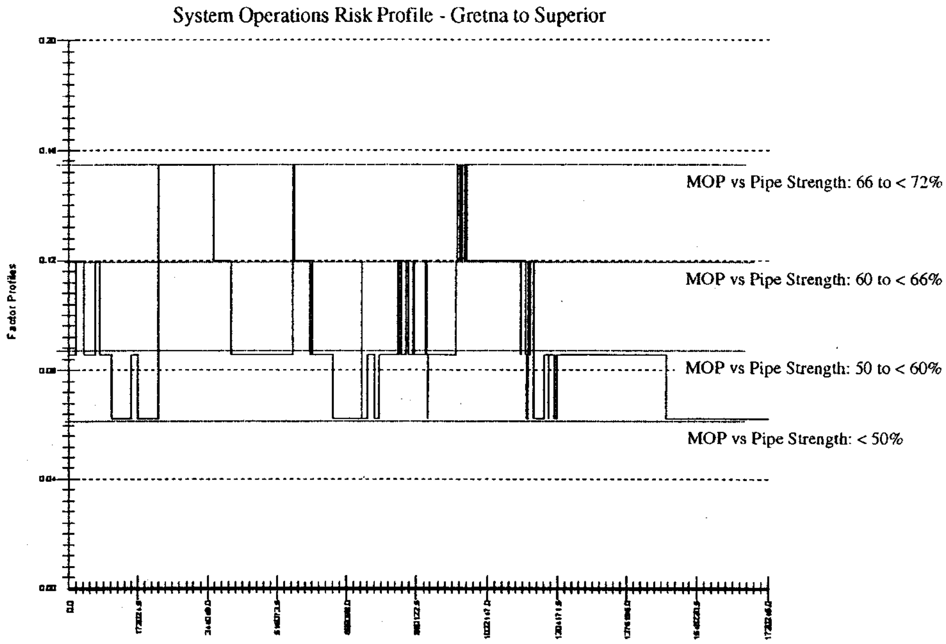
Risk Assessment Results

A review of the mainline risk assessment System Operations results by variable yields the following:

Systems Operations Variables	**Overview of Line 3 Systems Operations Variable Data**
Employee Training / Experience	New Procedures within the last 2 Years
Drug Testing Program	Effective
Safety Programs	Good
Leak Detection Subsystem	Yes
Continuous Remote Monitoring	Yes
Automatic Shutdown	Yes
MOP vs Pipe Strength	Variable.

Overview of Systems Operations Results

As can be seen by the data, variability only exists for the MOP versus Pipe Strength variable. This is reflected in the Systems Operations risk assessment profile provided below.



Consequence: Impact on Population, Environment and Business

<u>Current Risk Control or Mitigation Practices and Activities</u>

Oil Spill Response Program

Information on the Enbridge Oil Spill Response Program is found in the Operations and Procedures Book 7: Emergency Response.

Emergency Response Training

Enbridge has an extensive Emergency Response Training and Exercise Program which is reviewed annually. Emergency Response Training is documented in the Operations and Procedures Book 7: Emergency Response.

Emergency Flow Restricting Devices (EFRDs)

To Enbridge, EFRDs are sectionalizing valves. Sectionalizing valves are positioned to limit the volume of the release or fluid that would result in the event of a leak. The location of each sectionalizing valve, the configuration and type used, and the distance between valves along the pipeline are all considered to reduce the overall risk potential of a leak. Further information including guidelines for placement is located in the HCA Management Plan, Tab 8.

The mainline risk assessment Integrity Assessment Program (IAP) software performs volume out calculations based on the location of remote controlled sectionalizing valves, the elevation profile, flow rate, pipe outer diameter and wall thickness. These calculations can be used to assist in new sectionalizing valve placement decisions. An example volume out study is provided in Appendix D.

Impact on Population

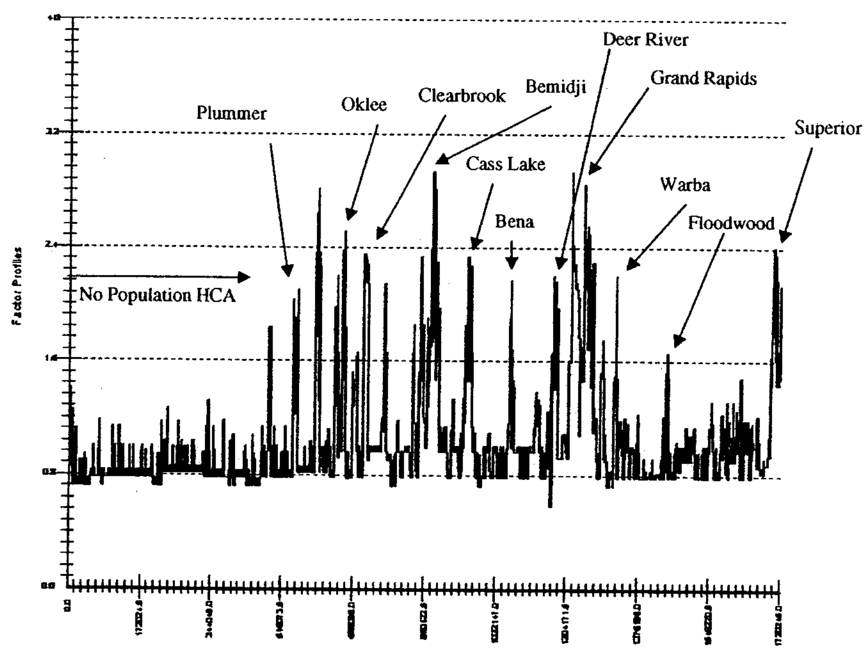
Risk Assessment Results

A review of the mainline risk assessment impact on population results by variable yields the following:

Impact on Population Variables	Overview of Line 3 Systems Operations Variable Data
Direct Population HCA	Variable
Transport Population HCA	Variable
Overlap Population HCA	Variable
Dispersion Potential	Variable
Population Sensitive Areas	Variable
Presence of Crossings	Variable
Initial Volume Loss	> 2500 to 3500 Bbls
Stabilization Volume Loss	Variable
Product Type	Light Crude
Response Effectiveness	Effective

Overview

Impact on Population Profile - Gretna to Superior

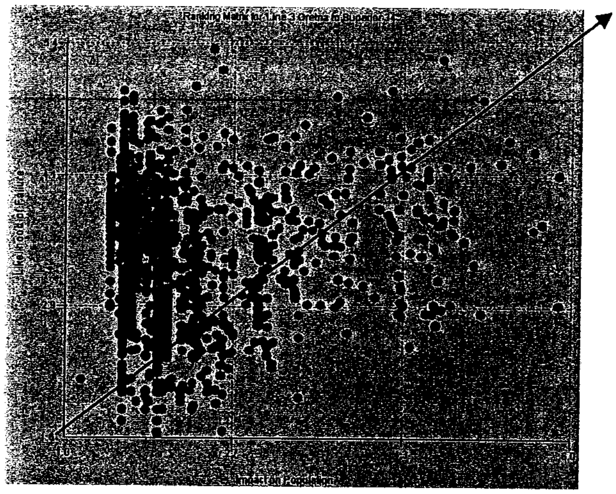


The top Impact on Population peaks correspond to populated areas with increased occurrence of crossings and population sensitive areas.

Top Impact on Population Consequence Areas

The risk ranking matrix below plots impact on population (x-axis) against total likelihood. Those 1000 ft sections in the upper right section of the table represent the highest risk areas. The table following provides the impact on population drivers for thee top twenty sections.

Increasing Risk



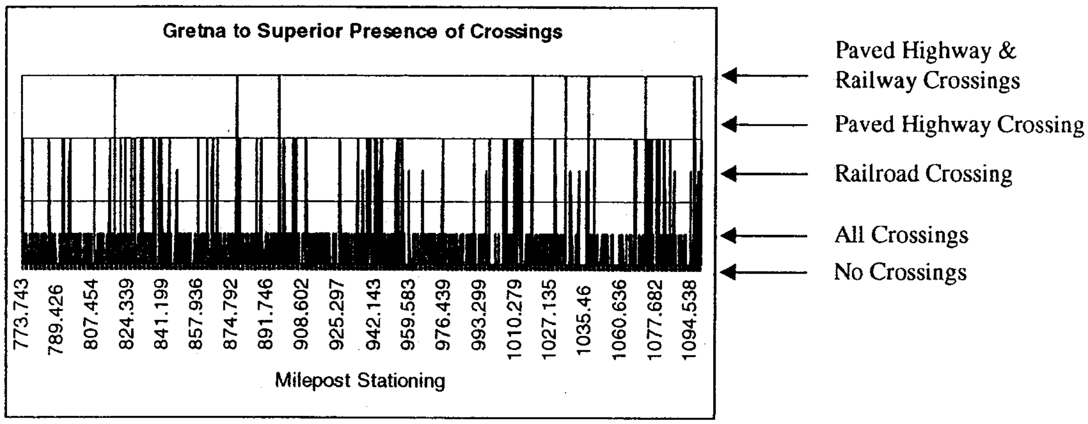
Section	Start MP	End MP	Crossing Presence	Population Sensitive Area	Direct HCA	Transport HCA	Overlap HCA	Stabilization Volume Out	Dispersion Potential	1000 ft Section Risk Rank
Deer River to Floodwood	1009.521	1009.71	No Crossings	None	OPA	OPA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	2
Deer River to Floodwood	1009.9	1010.089	Crossing Present	School or Hospital & 2 Facilities	OPA	None	None	2500 to 10000	Rolling Hills (2 - 9% slope)	1
Plummer to Clearbrook	885.14 40+24	885.14 50+24	No Crossings	School or Hospital & 2 Facilities	OPA	OPA	None	> 10000 to 20000	Steep Hills (>9% slope)	3
Deer River to Floodwood	993.898 445+00	993.898 455+00	No Crossings	1 Facility	OPA	OPA	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	6
Plummer to Clearbrook	885.14 30+24	885.14 40+24	Crossing Present	School or Hospital & 2 Facilities	OPA	OPA	None	> 10000 to 20000	Rolling Hills (2 - 9% slope)	4
Deer River to Floodwood	993.898 445+00	993.898 455+00	No Crossings	1 Facility	OPA	OPA	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	6
Plummer to Clearbrook	885.14 30+24	885.14 40+24	Crossing Present	School or Hospital & 2 Facilities	OPA	OPA	None	> 10000 to 20000	Rolling Hills (2 - 9% slope)	4
Plummer to Clearbrook	885.14 20+24	885.14 30+24	Paved Highway	School or Hospital & 2 Facilities	OPA	OPA	None	> 10000 to 20000	Flat (0 - 2% slope)	7
Deer River to Floodwood	1010.089	1010.279	Paved Highway	School or Hospital & 2 Facilities	None	OPA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	15
Deer River to Floodwood	1007.826	1007.957 3+09	Crossing Present	School and Hospital & 2 Facilities	OPA	OPA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	27
Deer River to Floodwood	993.898 535+00	993.898 545+00	No Crossings	None	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	5
Deer River to Floodwood	993.898 545+00	993.898 555+00	Paved Highway	None	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	8
Clearbrook to Cass Lake	938.934	939.123	Crossing Present	None	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	9
Plummer to Clearbrook	896.859	897.049	Crossing Present	None	OPA	OPA	None	2500 to 10000	Steep Hills (>9% slope)	23
Deer River to Floodwood	993.898 465+00	993.898 475+00	No Crossings	1 Facility	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	10
Deer River to Floodwood	993.898 515+00	993.898 525+00	Paved Highway	None	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	26
Deer River to Floodwood	1009.142	1009.332	Crossing Present	None	OPA	OPA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	17
Deer River to Floodwood	993.898 505+00	993.898 515+00	No Crossings	1 Facility	OPA	None	OPA	2500 to 10000	Rolling Hills (2 - 9% slope)	58
Deer River to Floodwood	1008.953	1009.142	No Crossings	School and Hospital & 2 Facilities	OPA	None	None	2500 to 10000	Steep Hills (>9% slope)	22
Deer River to Floodwood	1007.957 13+09	1007.957 23+09	Paved Highway	School and Hospital & 2 Facilities	OPA	None	None	2500 to 10000	Rolling Hills (2 - 9% slope)	28

The total risk score for the 1000 ft pipe sections is provided in the rightmost column of the table for comparison. Those sections of pipe with HCA population impacts and population sensitive areas tend to rank higher than those without.

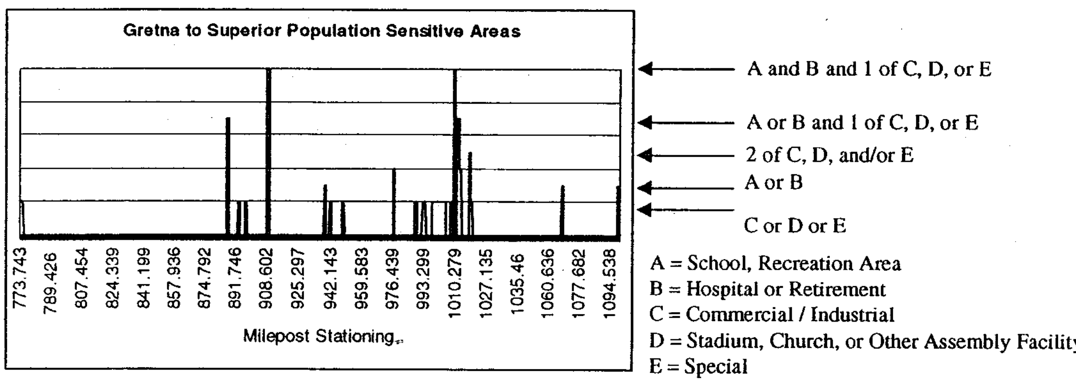
Review of Individual Consequence Drivers

An examination of the risk assessment results and/or data for each of the Impact on Population drivers is provided below.

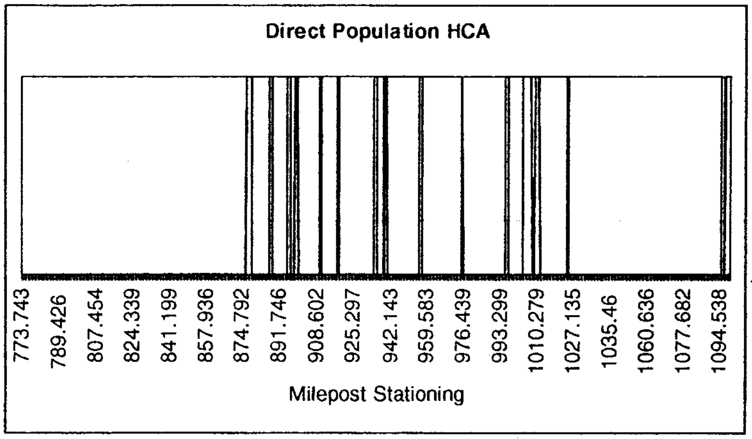
Presence of the Following (Crossings)



Population Sensitive Areas

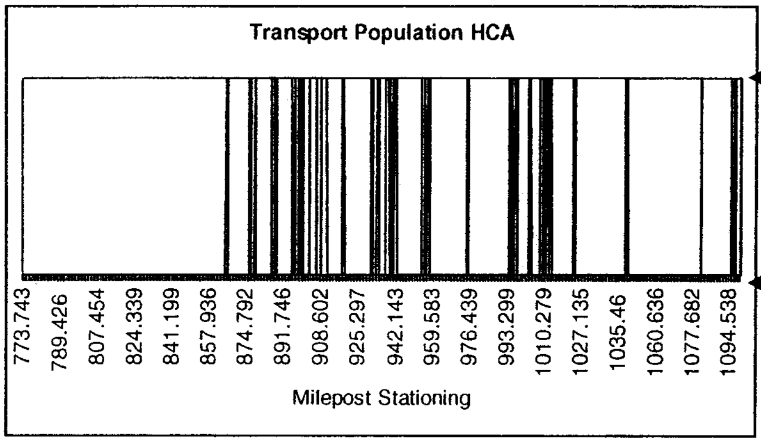


Direct, Transport and Overlap Population High Consequence Areas



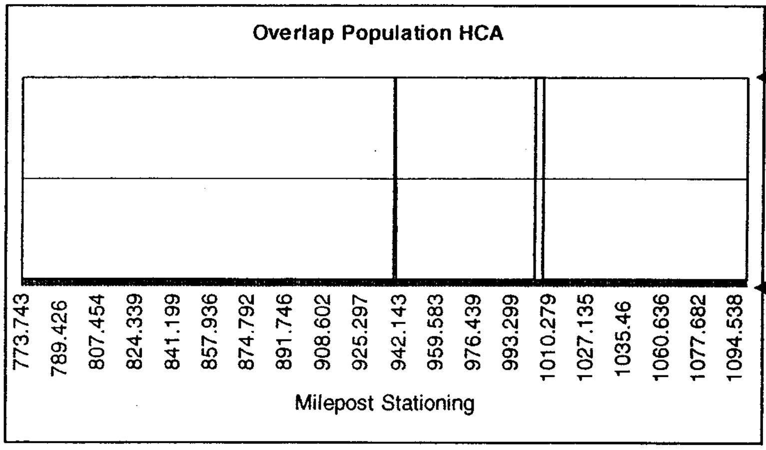
Direct High or Other Population Area

No Direct Population HCA



Transport High or Other Population Area

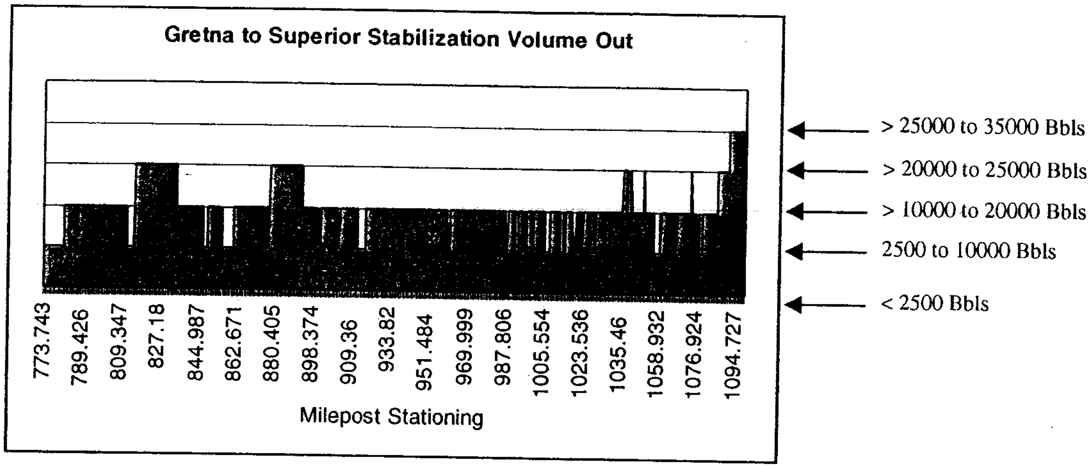
No Transport Population HCA



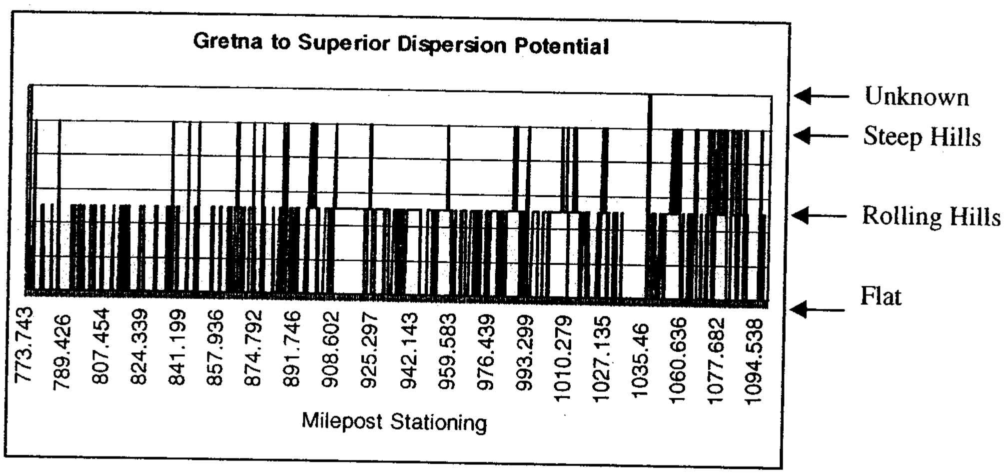
Overlap Other or High Population HCA

No Overlap Population HCA

Stabilization Loss



Dispersion Potential



Impact on Environment

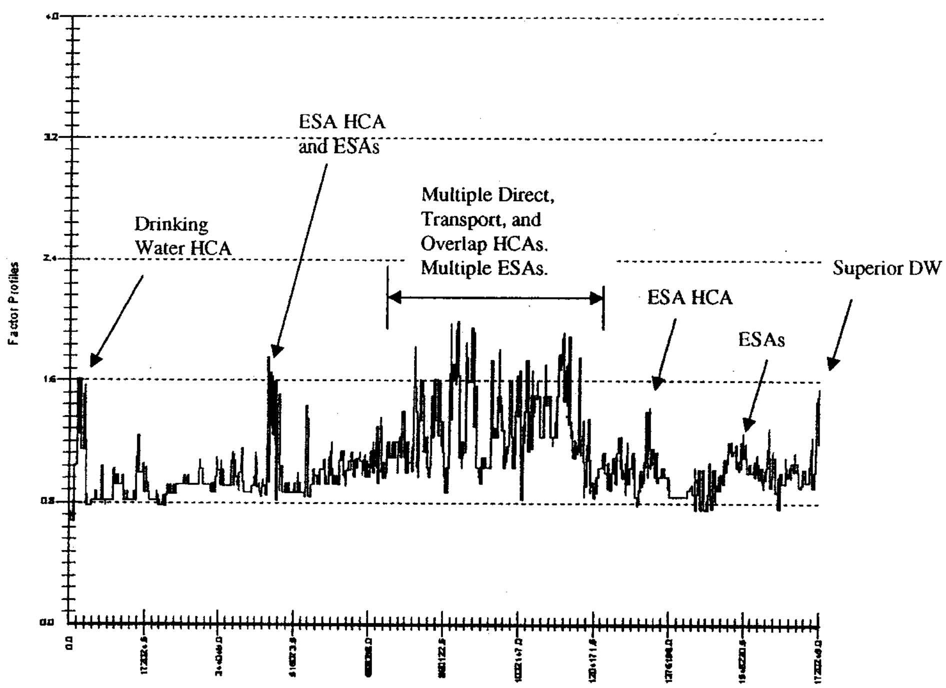
Risk Assessment Results

A review of the mainline risk assessment impact on environment results by variable yields the following:

Impact on Population Variables	Overview of Line 3 Systems Operations Variable Data
Environmentally Sensitive Areas	Variable
Soil Type	Variable
Adjacent Land Use	Variable
Direct Environment HCA	Variable
Transport Environment HCA	Variable
Overlap Environment HCA	Variable
Dispersion Potential	Variable
Accessibility	Unknown. Data has not been collected.
Initial Volume Loss	> 2500 to 3500 Bbls
Stabilization Volume Loss	Variable
Product Type	Light Crude
Response Effectiveness	Effective
Redundancy	Sole Supplier
Groundwater Depth	Unknown

Overview

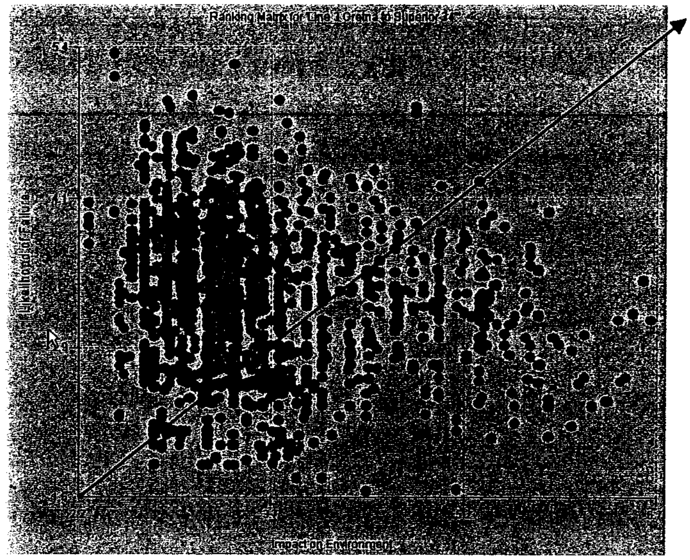
Impact on Environment - Gretna to Superior



Impact on environment risk peaks generally correspond with the occurrence of one or more high consequence areas or environmentally sensitive areas.

Top Impact on Environment Consequence Areas

The risk ranking matrix below plots impact on environment (x-axis) against total likelihood. Those 1000 ft sections in the upper right section of the table represent the highest risk areas. The table below provides the impact on environment drivers for the top twenty sections.



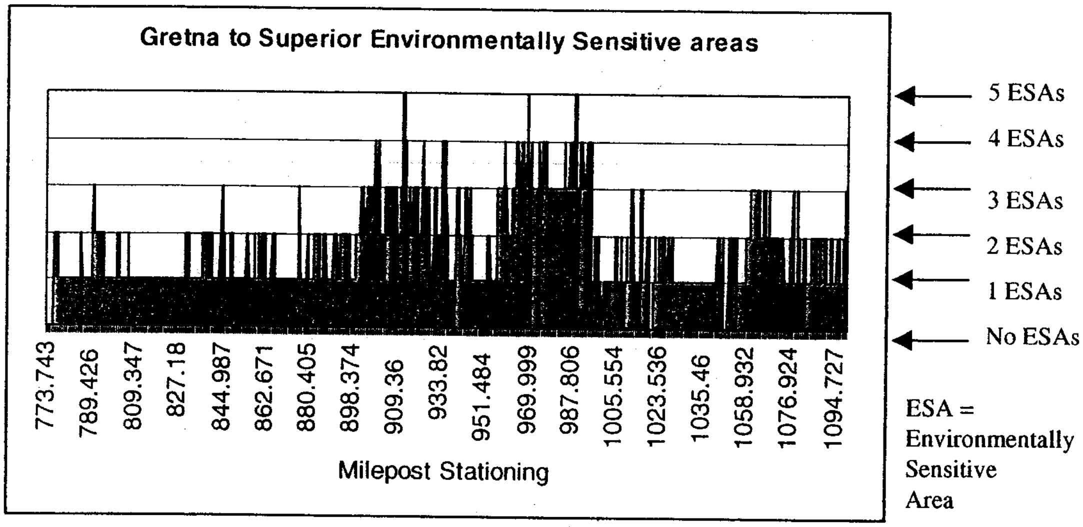
Increasing Risk

Section	Start MP	End MP	Env Sensitive Areas (ESA)	Soil Type	Adjacent Land Use	Direct HCA	Overlap HCA	Transport HCA	Stabilization Volume Loss	Dispersion Potential	1000 Ft Section Risk Rank
Clearbrook to Cass Lake	937.608	937.797	None	Sand	Residential / Parkland	ESA	ESA	DW & ESA	2500 to 10000	Flat (0 - 2% slope)	18
Clearbrook to Cass Lake	940.638	940.828	One ESA	Loam	Residential / Parkland	DW	DW	DW	2500 to 10000	Rolling Hills (2 - 9% slope)	81
Clearbrook to Cass Lake	940.26	940.449	Two ESA	Loam	Residential / Parkland	ESA	ESA	DW	2500 to 10000	Rolling Hills (2 - 9% slope)	310
Clearbrook to Cass Lake	938.744	938.934	Three ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	12
Clearbrook to Cass Lake	938.555	938.744	Three ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	21
Cass Lake to Deer River	951.484 201+30	951.484 211+30	Three ESA	Sand	Indigenous Lands	CNW & ESA	CNW	CNW	2500 to 10000	Rolling Hills (2 - 9% slope)	29
Clearbrook to Cass Lake	938.934	939.123	Two ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	9
Clearbrook to Cass Lake	939.502	939.691	Three ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	144
Clearbrook to Cass Lake	937.419	937.608	One ESA	Sand	Residential / Parkland	None	None	DW & ESA	2500 to 10000	Rolling Hills (2 - 9% slope)	119
Cass Lake to Deer River	985.65 13+54	985.65 23+54	Three ESA	Sand	Indigenous Lands	CNW & ESA	None	CNW	< 2500	Steep Hills (>9% slope)	681
Clearbrook to Cass Lake	939.123	939.313	Three ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	30
Clearbrook to Cass Lake	947.635	947.825	One ESA	Sand	Indigenous Lands	DW & ESA	None	ESA	2500 to 10000	Rolling Hills (2 - 9% slope)	557
Cass Lake to Deer River	986.67	986.859	Three ESA	Sand	Residential / Parkland	ESA	None	ESA & CNW	< 2500	Rolling Hills (2 - 9% slope)	209
Cass Lake to Deer River	985.65 33+54	986.48	Four ESA	Sand	Residential / Parkland	None	None	ESA & CNW	2500 to 10000	Steep Hills (>9% slope)	218
Clearbrook to Cass Lake	946.878	947.067	One ESA	Sand	Indigenous Lands	DW	None	DW & ESA	2500 to 10000	Flat (0 - 2% slope)	230
Cass Lake to Deer River	986.48	986.67	Four ESA	Sand	Residential / Parkland	None	None	ESA & CNW	2500 to 10000	Steep Hills (>9% slope)	473
Clearbrook to Cass Lake	932.684	932.873	Four ESA	Sand	Indigenous Lands	None	None	ESA	2500 to 10000	Rolling Hills (2 - 9% slope)	24
Clearbrook to Cass Lake	939.881	940.07	Two ESA	Sand	Residential / Parkland	ESA	ESA	None	2500 to 10000	Rolling Hills (2 - 9% slope)	74
Cass Lake to Deer River	985.65 23+54	985.65 33+54	Four ESA	Sand	Indigenous Lands	ESA	None	CNW	< 2500	Steep Hills (>9% slope)	1038
Clearbrook to Cass Lake	940.99 1+44	941.205	One ESA	Loam	Indigenous Lands	DW	DW	None	2500 to 10000	Rolling Hills (2 - 9% slope)	130

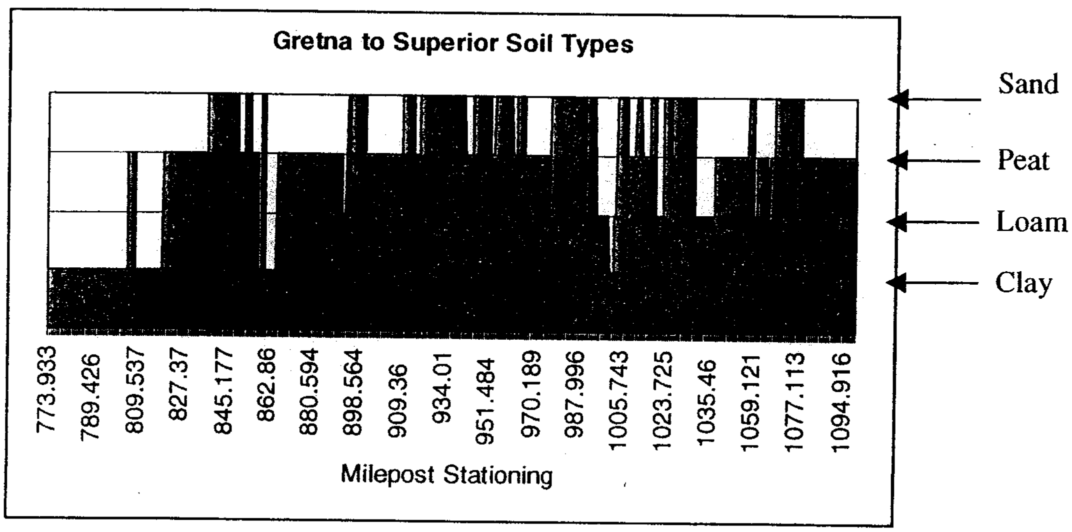
The total risk score for the 1000 ft sections is provided in the rightmost column of the table for comparison. Those sections of pipe with one or more HCA impact types, one or more environmentally sensitive areas and high dispersion potential generally rank higher than those without.

Review of Individual Consequence Drivers

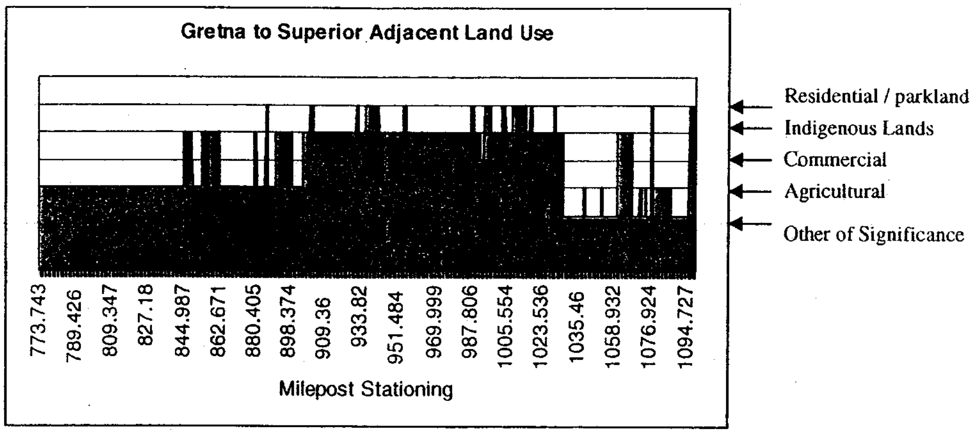
Environmentally Sensitive Areas



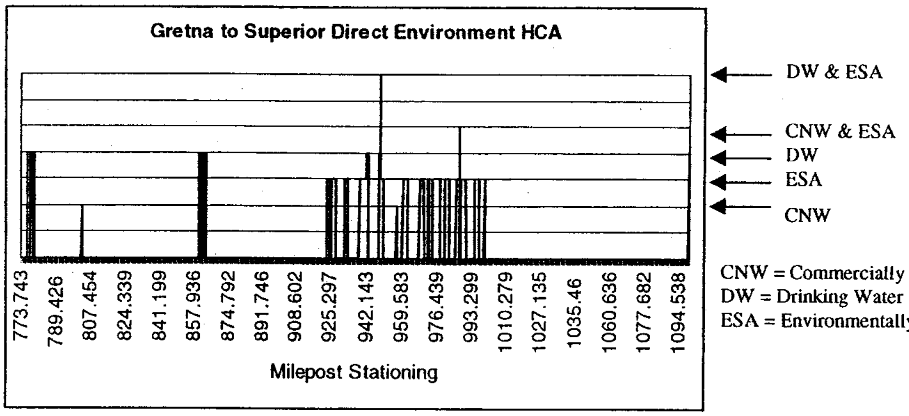
Soil Type



Adjacent Land Use

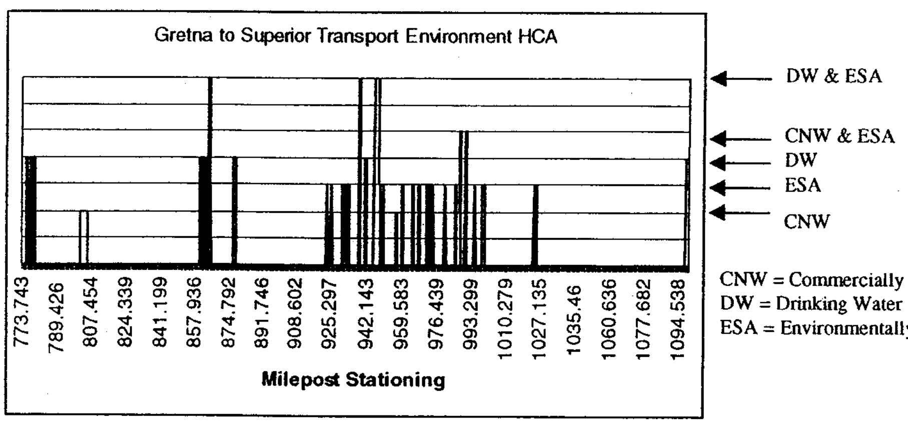


Direct Environmental High Consequence Areas



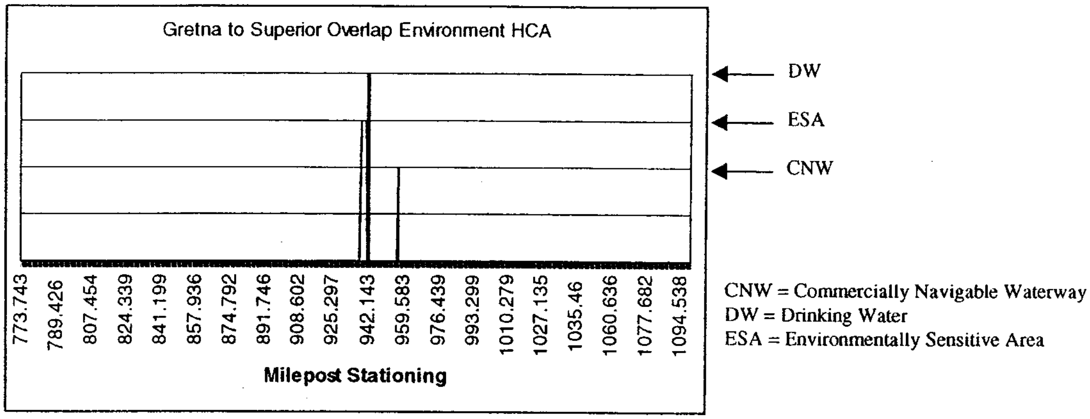
CNW = Commercially Navigable Waterway
DW = Drinking Water
ESA = Environmentally Sensitive Area

Transport Environmental High Consequence Areas

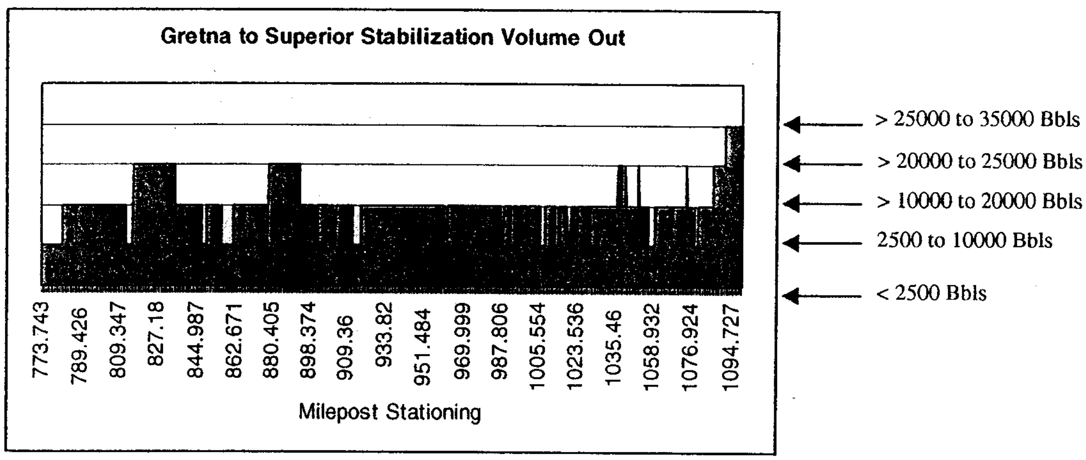


CNW = Commercially Navigable Waterway
DW = Drinking Water
ESA = Environmentally Sensitive Area

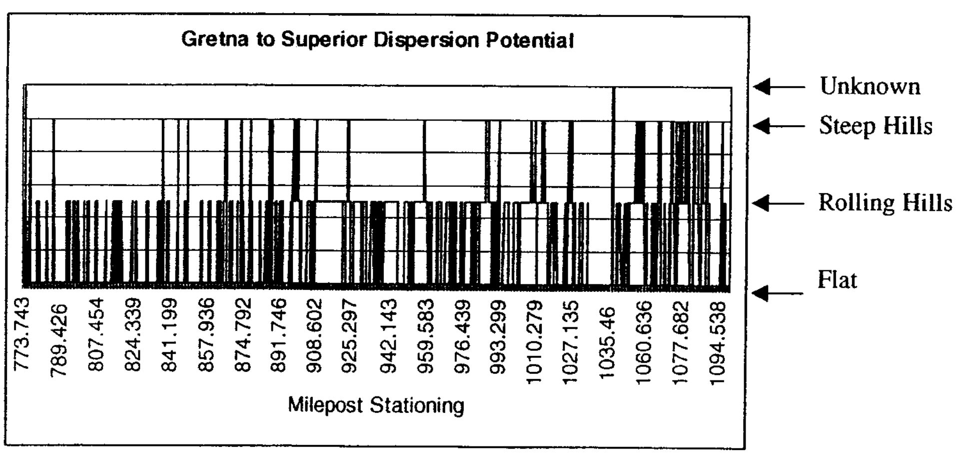
Overlap Environmental High Consequence Areas



Stabilization Volume Out



Dispersion Potential



Impact on Business

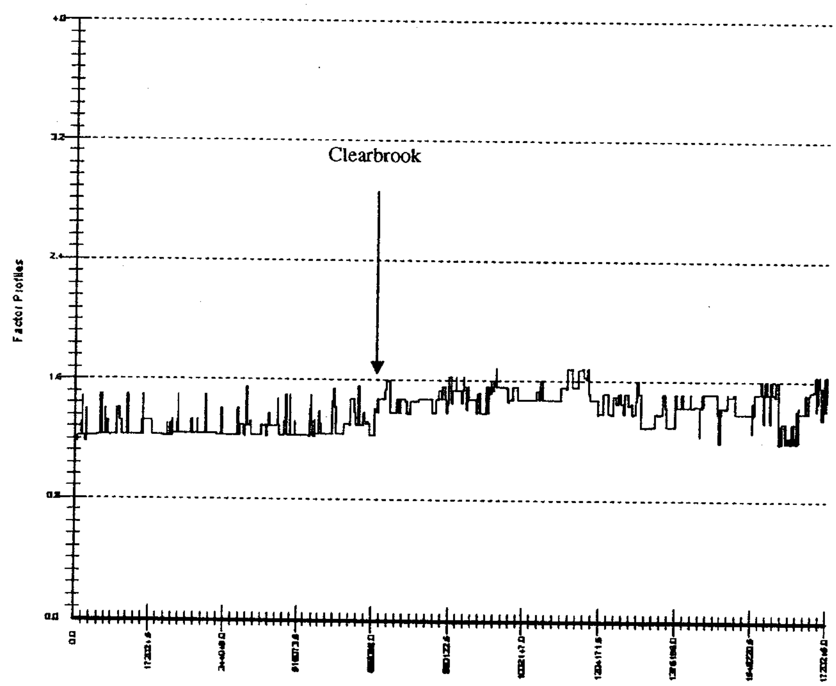
<u>Risk Assessment Results</u>

A review of the mainline risk assessment impact on business results by variable yields the following:

Impact on Population Variables	Overview of Line 3 Systems Operations Variable Data
Adjacent Land Use	Variable
Accessibility	Unknown. Data has not been collected.
Out of Service Hours	Variable
Initial Volume Loss	> 2500 to 3500 Bbls
Stabilization Volume Loss	Variable
Response Effectiveness	Effective
Redundancy	Sole Supplier from Gretna to Clearbrook Limited Alternate Source from Clearbrook to Superior
Repair and Cleanup Costs (based on Pipe Outer Diameter)	> 22" to 36"

Overview

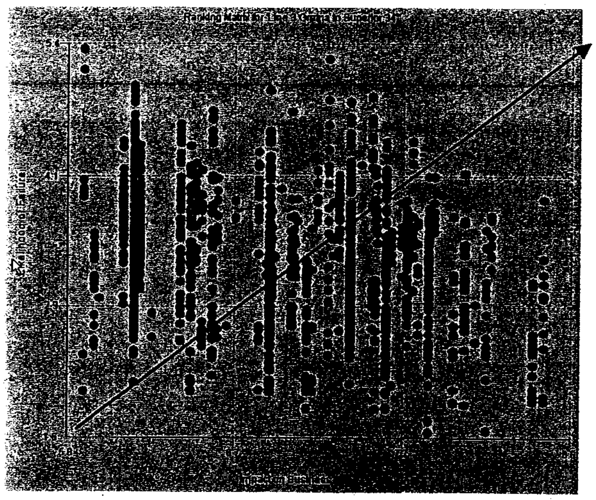
Impact on Business - Gretna to Superior



There is a step-up in the impact on business risk profile downstream of Clearbrook due to increased occurrence of commercial and industrial land use and significantly higher out of service times. Both of these correlate to increased population presence.

Top Impact on Business Consequence Areas

The risk ranking matrix below plots the impact on business data (x-axis) against the total likelihood. Those 1000 ft sections in the upper right section of the table represent the highest risk areas. The table below provides the impact on business drivers for these sections.



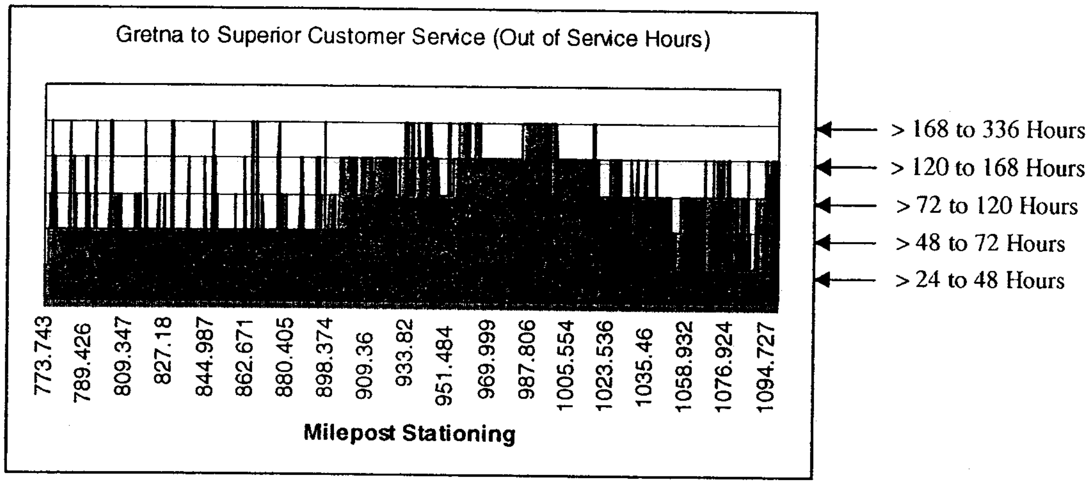
Increasing Risk

Section	Start MP	End MP	Redundancy	Customer Service (Out of Service Hours)	Adjacent Land Use	Stabilization Volume Out (bbls)	1000 ft Section risk Rank
Deer River to Floodwood	1009.9	1010.089	Limited Alternate Source	> 120 to 168 hours	Residential / Parkland	2500 to 10000	1
Viking to Plummer	863.807	863.997	Sole Supplier	> 168 to 336 hours	Agricultural	2500 to 10000	16
Plummer to Clearbrook	893.071	893.261	Sole Supplier	> 120 to 168 hours	Indigenous Lands	2500 to 10000	128
Deer River to Floodwood	1009.521	1009.71	Limited Alternate Source	> 120 to 168 hours	Residential / Parkland	2500 to 10000	2
Viking to Plummer	866.08	866.269	Sole Supplier	> 168 to 336 hours	Agricultural	2500 to 10000	123
Viking to Plummer	865.891	866.08	Sole Supplier	> 168 to 336 hours	Agricultural	2500 to 10000	150
Plummer to Clearbrook	893.64	893.829	Sole Supplier	> 120 to 168 hours	Indigenous Lands	2500 to 10000	11
Plummer to Clearbrook	885.14 30+24	885.14 40+24	Sole Supplier	> 120 to 168 hours	Residential / Parkland	> 10000 to 20000	4
Deer River to Floodwood	993.898 535+00	993.898 545+00	Limited Alternate Source	> 120 to 168 hours	Indigenous Lands	2500 to 10000	5
Deer River to Floodwood	993.898 155+00	993.898 165+00	Limited Alternate Source	> 168 to 336 hours	Indigenous Lands	2500 to 10000	155
Viking to Plummer	864.13 13+07	864.565	Sole Supplier	> 168 to 336 hours	Agricultural	2500 to 10000	44
Deer River to Floodwood	993.898 465+00	993.898 475+00	Limited Alternate Source	> 120 to 168 hours	Commercial	2500 to 10000	10
Plummer to Clearbrook	885.14 40+24	885.14 50+24	Sole Supplier	> 120 to 168 hours	Residential / Parkland	> 10000 to 20000	3
Viking to Plummer	863.997	864.13 3+07	Sole Supplier	> 168 to 336 hours	Agricultural	2500 to 10000	65
Deer River to Floodwood	1009.71	1009.9	Limited Alternate Source	> 120 to 168 hours	Residential / Parkland	2500 to 10000	45
Gretna to Donaldson	785.294	785.484	Sole Supplier	> 120 to 168 hours	Agricultural	2500 to 10000	175
Plummer to Clearbrook	893.261	893.45	Sole Supplier	> 120 to 168 hours	Indigenous Lands	2500 to 10000	161
Deer River to Floodwood	993.898 175+00	993.898 185+00	Limited Alternate Source	> 168 to 336 hours	Indigenous Lands	2500 to 10000	113
Deer River to Floodwood	993.898 405+00	993.898 415+00	Limited Alternate Source	> 120 to 168 hours	Commercial	2500 to 10000	71
Cass lake to Deer River	951.484 151+30	951.484 161+30	Sole Supplier	> 120 to 168 hours	Commercial	2500 to 10000	68

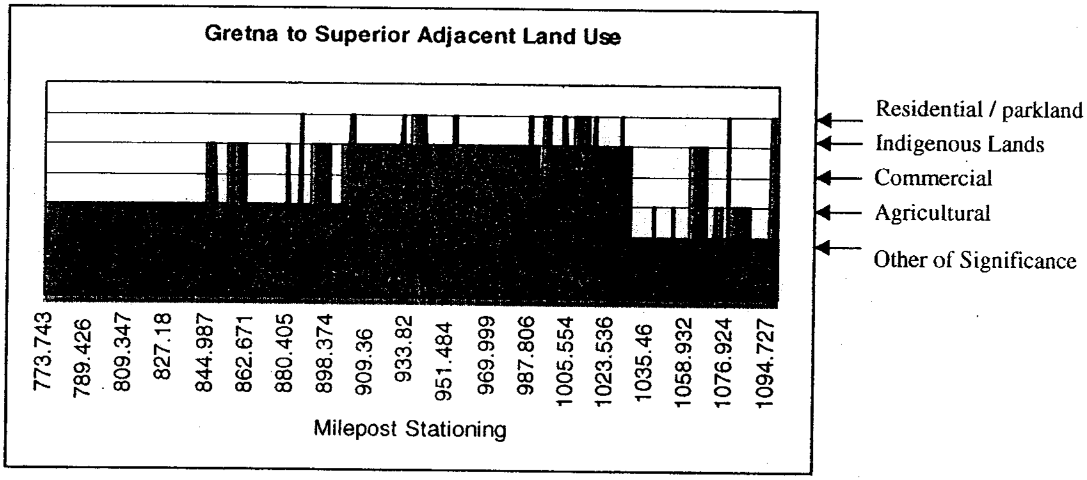
The total risk score for the 1000 ft pipe sections is provided in the rightmost column for comparison. Those sections of pipe with poor redundancy, high out of service hours and sensitive adjacent land use tend to rank higher than those without.

Review of Individual Consequence Drivers

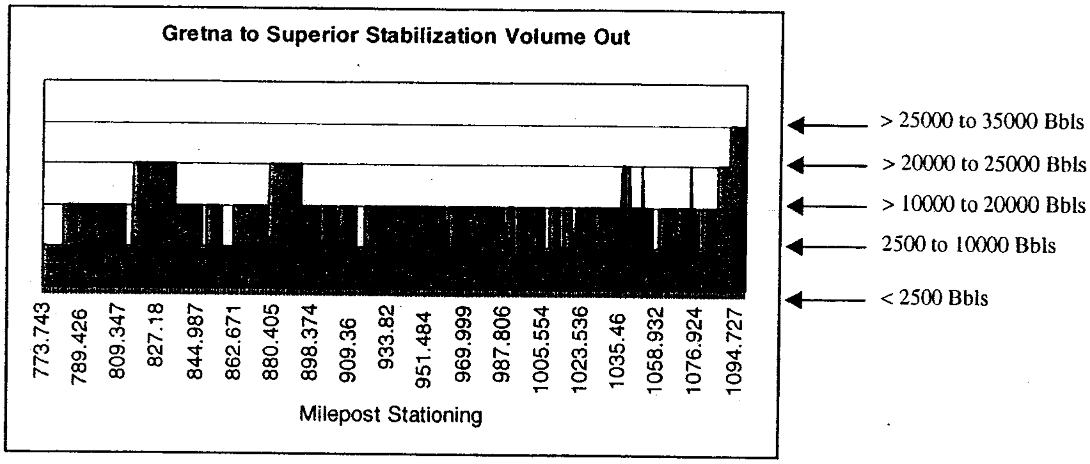
Customer Service (Out of Service Hours) (The Amount of Time it Takes to Replace One Joint of Pipe)



Adjacent Land Use



Stabilization Volume Out



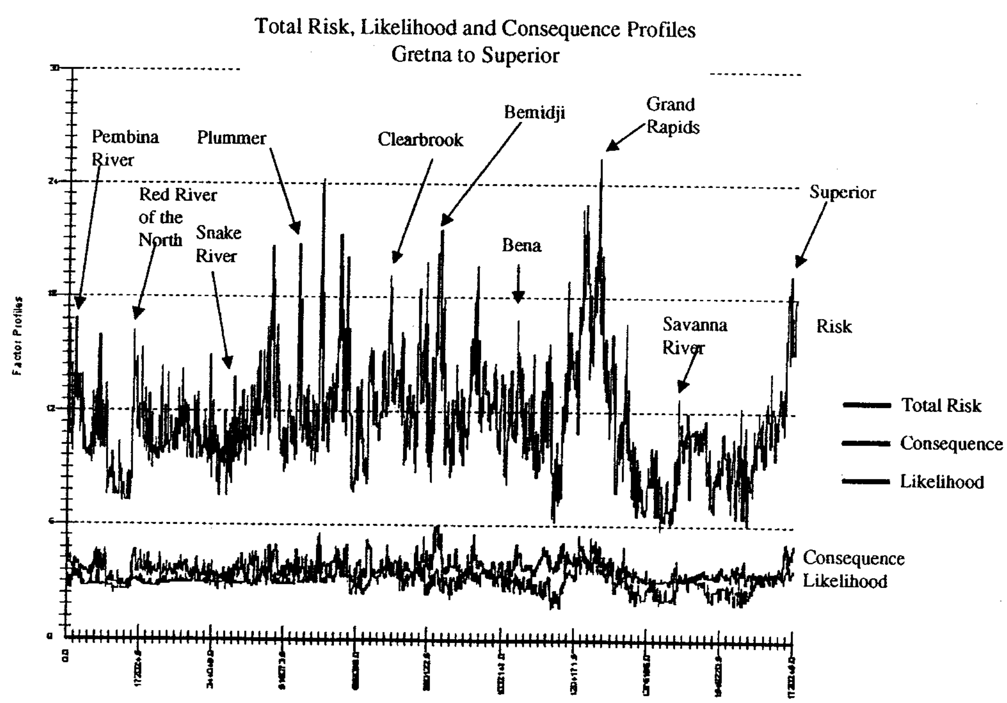
Total Risk

<u>Current Risk Control or Mitigation Practices or Activities</u>

Incident Investigation

Enbridge has investigated occurring incidents in the past using the guidelines documented in Book 1: General Reference, Section 02-02-02. Additional information regarding incident investigation is provided in the HCA Management Plan, Tab 8.

<u>Risk Assessment Results</u>



The limited likelihood variability as compared to that for consequence yields a total risk profile largely driven by consequence. As illustrated above, the high risk peaks are associated with population or environmentally sensitive areas and HCAs.

Static and Addressable Conditions

Variables included in the mainline risk assessment can be subdivided into those which are static and those which can be addressed. Static variables are those which measure a condition which can not be changed (e.g. occurrence of third party leaks) or can not be easily altered unless a significant change is proposed (e.g. rerouting a pipeline). Variables which can be addressed include those for which risk control and/or mitigation measures can more readily be proposed or implemented (e.g. improving the condition of the right-of-way).

Risk control and / or mitigation strategies either increase effectiveness of existing processes, procedures or guidelines, or make an improvement or physical change to the current condition.

The following tables examine the variables used in the mainline risk assessment and whether or not they are addressable or static.

Corrosion

The mainline risk assessment model includes the following (after-repair; critical defects repaired) in-line inspection data:

- Defect Wall Thickness Loss
- Defect Density
- Defect RPR

A fourth variable providing a gross trap to trap pipe section indicator of corrosion growth (Integrity Corrosion Factor) is included in the risk assessment.

Corrosion mitigation and/or control is addressed by the Enbridge defect management approach. More information on this approach is provided earlier in this document.

Design & Materials

The following table outlines the design and materials data included in the mainline risk assessment model.

Addressable Measures	Potential Risk Mitigation or Prevention for Addressable Measures
Pressure Cycling	Alter pressure regime
Dents per Mile	Repair dents
OD / WT Ratio	Replace existing pipe with heavier wall pipe.
Longitudinal Weld Type	Pipe replacement or repair
Manufacture / Shipping Induced Defects	Pipe replacement or repair
MOP vs Pipe Strength	Change operating pressure regime
Pipe Age	Pipe Replacement
Hydrotest History	Consider pressure testing or corrective action.

Ground Movement

The following table outlines the ground movement data included in the mainline risk assessment:

Static Measure
Presence of Major Water Crossing
Presence of Seismic Fault Line
High Ground Instability
Natural / Man-made Seismic Area
Nearby Mining Operations

Addressable Measures	Potential Risk Mitigation or Prevention for Addressable Measures
Weights or Hold Downs for Major Water Crossings	Add weights or hold downs.
Ground Movement Monitoring	Increase effectiveness of ground movement monitoring.

Third Party

The following table outlines the third party data included in the mainline risk assessment.

Static Measures
Construction Activity
Farm Activity
Crossing Exposure
Third Party Leak Rate

Addressable Measures	Potential Risk Mitigation or Prevention for Addressable Measure
One Call Effectiveness	Increase its effectiveness
Patrol Frequency	Increase Frequency
Public Education	Increase its Effectiveness
Depth of Cover	Increase depth of cover and/or provide additional measures such as fencing, protective plates, signs, etc.
Age of Caliper / Geometry Tool Runs	Increase frequency of Geometry Tool Runs
Line Marking	Make Improvements
Right-of-way Condition	Make Improvements
Anomaly Type and Orientation	Make Improvements through repair.

System Operations

The following table outlines the systems operations data included in the mainline risk assessment.

Addressable Measures	Potential Risk Mitigation or Prevention for Addressable Measures
Employee Training / Experience	Increase effectiveness of training
Drug Testing Program	Increase effectiveness of drug testing program
Safety Programs	Increase effectiveness of safety programs
Leak Detection Subsystem	Make improvements to increase effectiveness of leak detection systems
Continuous Remote Monitoring	Make changes to increase locations with continuous remote monitoring
Automatic Shutdown	Make changes to increase locations with automatic shutdown capability
MOP vs Pipe Strength*	Make changes to reduce MOP relative to Pipe Strength

* The MOP calculation uses the worst case discharge and suction values for Line 3 (Base Maximum Discharge and Suction Remote Warning, respectively), thus does not reflect current operating conditions.

Consequence

The following table outlines the consequence data included in the mainline risk assessment:

Static Measures
Environmentally Sensitive Areas
Soil Type
Adjacent Land Use
Direct HCA
Transport HCA
Overlap HCA
Dispersion Potential
Population Sensitive Areas
Presence of Crossings
Out of Service Hours
Initial Volume Out*
Product Type

Addressable Measures	**Potential Risk Mitigation or Prevention for Addressable Measures**
Stabilization Loss	Additional Valve Placement
Response Effectiveness	Improve Effectiveness
Redundancy	Add Redundancy
Groundwater Depth**	Gain additional data about groundwater depth
Accessibility**	Gain additional data about accessibility.

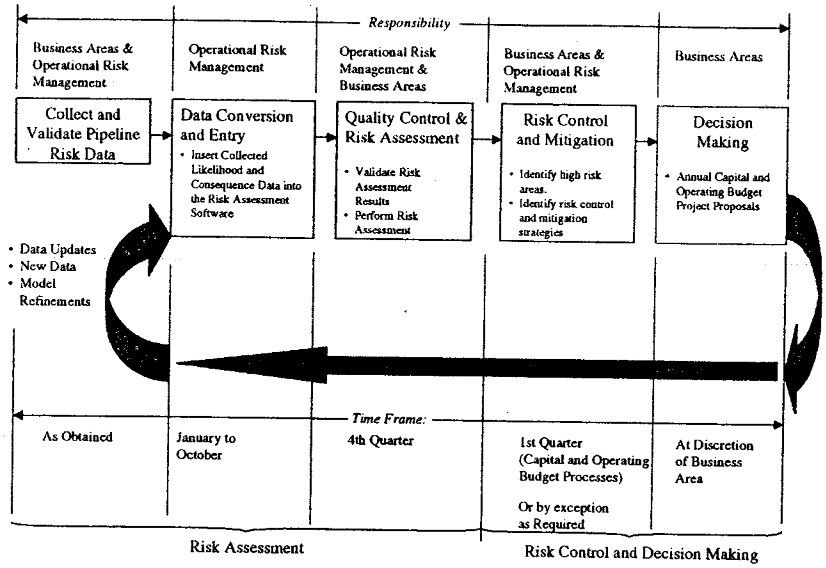
* Initial Volume Out is based on the pipeline design capacity.
** Groundwater Depth and Accessibility are included as being addressable only because neither have information at this time - thus both are set to worst case.

Risk Mitigation and Control

The results of the Line 3 mainline risk assessment and pipeline integrity risk management as described in this document coupled with Region and local knowledge and expertise are inputs into the project identification and prioritization decision making activities of the Enbridge annual Operating and Capital Budget processes. These processes are briefly described below. A more comprehensive description is available in the HCA Management Plan.

Schedule and On-Going Management Process

The figure below illustrates the risk management processes and timeframes which encompass risk assessment, risk control and mitigation. Performance monitoring and feedback is a continuous process performed throughout the year. Risk assessment, risk control and mitigation, and decision making processes and activities are performed annually corresponding to the Enbridge capital and operating budget cycles.



Identification of Risk Control and Mitigation Activities

Region staff will use the Line 3 risk assessment results and their own expertise / knowledge about the pipeline and the terrain through which it traverses as input to the identification and prioritization of appropriate risk control and mitigation activities. This combination of the risk assessment outcome with local expertise results in the optimal outcome through which the risk control and mitigation activities must be defined. Discussions on possible risk control and mitigation activities occur annually starting in the 1st quarter of each year.

Responsibilities

Regional Management is responsible for making decisions regarding what risk control or mitigation measures are proposed for addressing areas of high risk. Operational Risk Management facilitates the use of the risk assessment results plus risk mitigation and/or control discussions. The results of the mainline risk assessment tool provide decision support for these proposed measures and/or activities.

Decision Making Framework

Enbridge has well established processes for bringing forth, justifying, and approving capital and operating budget projects. Procedures are also in place to address areas of immediate concern to ensure prompt and responsible action, outside the normal budget processes.

Annual Update

On an annual basis, beginning in May and ending with the following year's budget cycle, Operational Risk Management requests data updates, compiles received data, then generates and distributes risk assessment results. The Line 3 Risk Management Plan illustrates the risk assessment results generated in late 2003 to be used as input into the 2004 Capital Budget and Operating Budget processes. This same process will be repeated for upcoming years and the Line 3 Risk Management Plan will be updated accordingly.

Performance Measures

Operational Risk Management has defined a number of performance measures to ensure that the results of the mainline risk assessment program and projects / activities proposed in whole or in part on risk reduction are as expected. These measures will be applied to the Line 3 projects or activities implemented on behalf of risk control or mitigation. The measures are:

<u>Direct Measures</u>

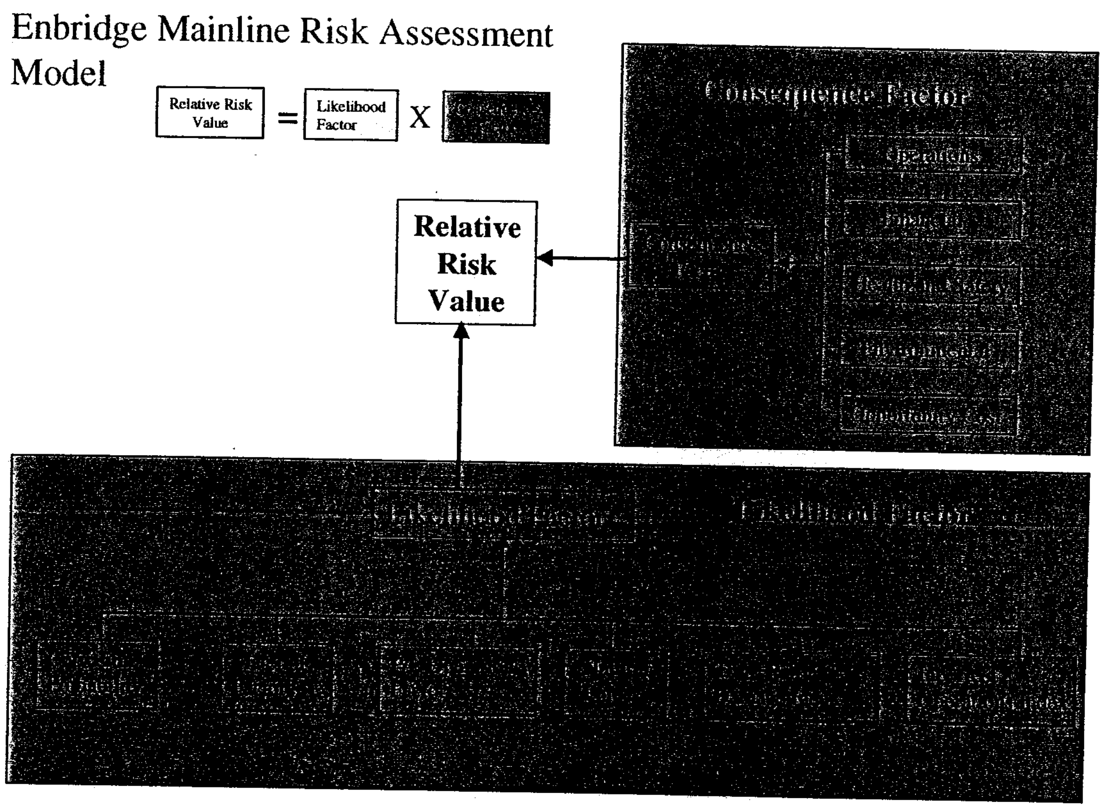
- Reduction in the overall risk profile.
- Measure of the risk reduction achieved by projects justified in whole or in part on risk reduction.
- Measure of the cost effectiveness of risk reduction projects.

<u>Indirect Measures</u>

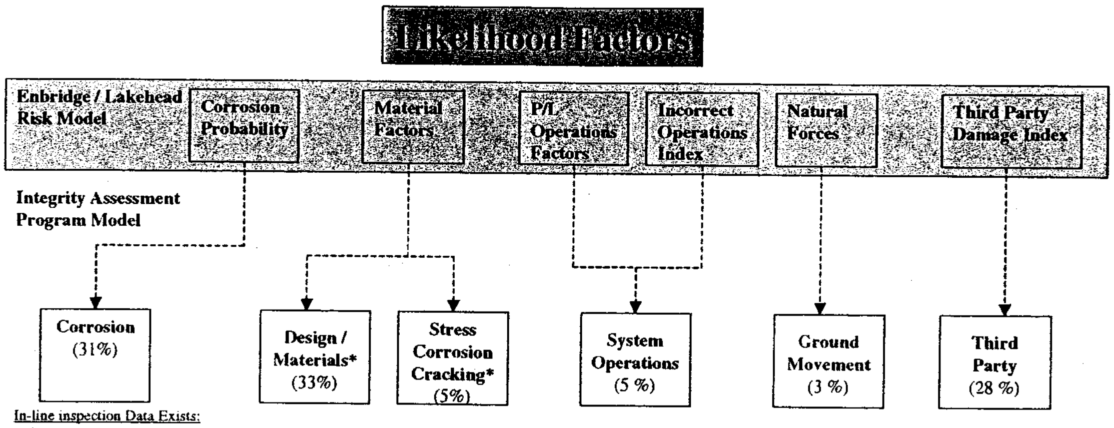
- Identification of new, previously unrecognized areas of risk.
- Identification of existing areas of low risk where excessive mitigation activities or costs are being incurred.
- Identification of innovative risk control and mitigation approaches.
- Identification of projects providing risk mitigation coverage over and above existing regulations and/or compliance requirements.

Appendix A

Mainline Risk Assessment Model



December, 2003



Corrosion (31%)

In-line inspection Data Exists:
- Defect Wall Thickness Loss
- Defect Density
- Defect RPR
- Corrosion Growth (Integrity Corrosion Factor)

No In-line Inspection Data
- Coating Design
- Pipe Age
- CP Installed at Time of Construction
- Corrosion Failure History
- MOP vs Pipe Strength
- CP Maintenance Frequency
- Pigging Frequency (Line Cleaning)
- Inhibitor Used
- Soil Type
- Laminar Flow
- Highly Corrosive Soils
- Poorly Drained Area
- Close Interval Criteria Issues

Design / Materials* (33%)
- Pressure Cycling
- Dents per Mile
- Outer Diameter / Wall Thickness Ratio
- Longitudinal Weld Type
- Manufacture / Shipping Induced Defects
- MOP vs Pipe Strength
- Pipe Age
- Hydrotest History

Stress Corrosion Cracking* (5%)
- Operating Pressure
- Induced Stresses
- Coating Susceptibility to Breakdown
- Soil pH
- High Soil Moisture Content
- CP System Accesses Pipe

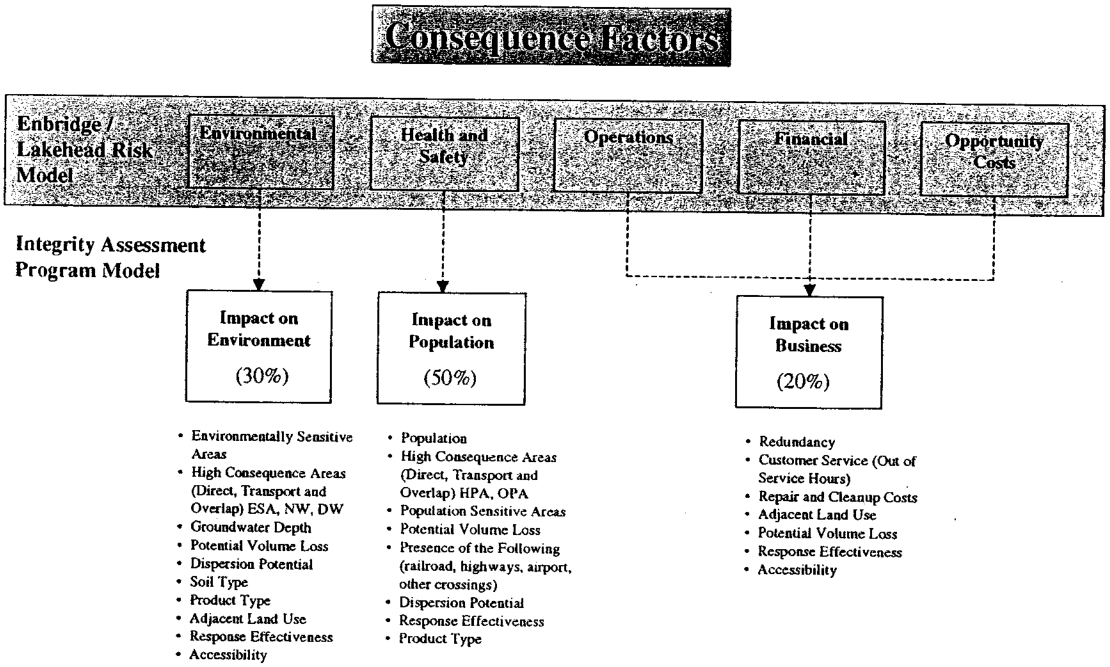
System Operations (5 %)
- Employee Training / Experience
- Drug Testing Program
- MOP vs Pipe Strength
- Pressure Safety Systems
- Safety Programs
- Leak Detection Subsystem
- Continuous Remote Monitoring
- Automatic Shutdown

Ground Movement (3 %)
- Major Fault and / or Water Crossings
- High Ground Instability
- Ground Movement Monitoring Criteria
- Flood Plain Area
- Weights or Hold Downs, for Major Water Crossings
- Natural or Man-made Seismic Area
- Nearby Mining Operations

Third Party (28 %)
- Construction Activity
- Farm Activity
- One Call Effectiveness
- Patrol Frequency
- Line Marking
- Depth of Cover
- ROW Condition
- Public Education
- Crossing Exposure (ft of crossings per sect length)
- Third Party Leak History
- Anomaly Type
- Anomaly Orientation
- Age of Caliper or Geometry Run

* If crack detection in-line inspection results are available, then the Stress Corrosion Cracking (SCC) variables are not required. If crack detection in-line inspection results are not available, then the SCC variables are populated and the weightings for Design and Materials and SCC are adjusted to 28% and 5% respectively.

December, 2003



December, 2003

Appendix B

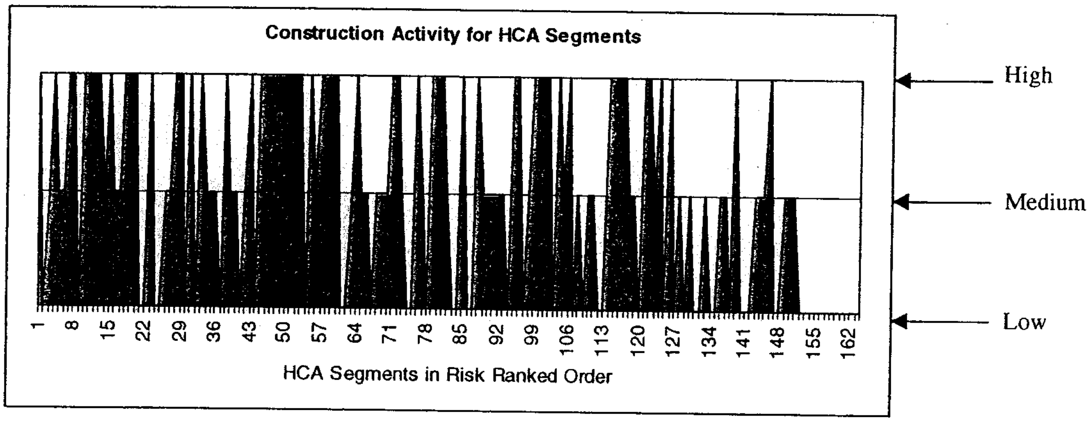
HCA Segment Third Party Risk Drivers

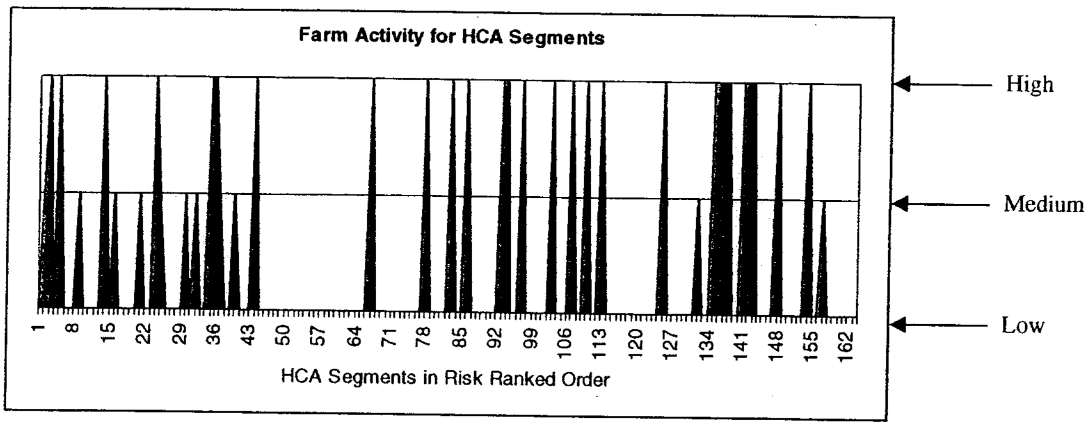
This appendix examines the Line 3 Third Party Risk Drivers for HCA Segments.

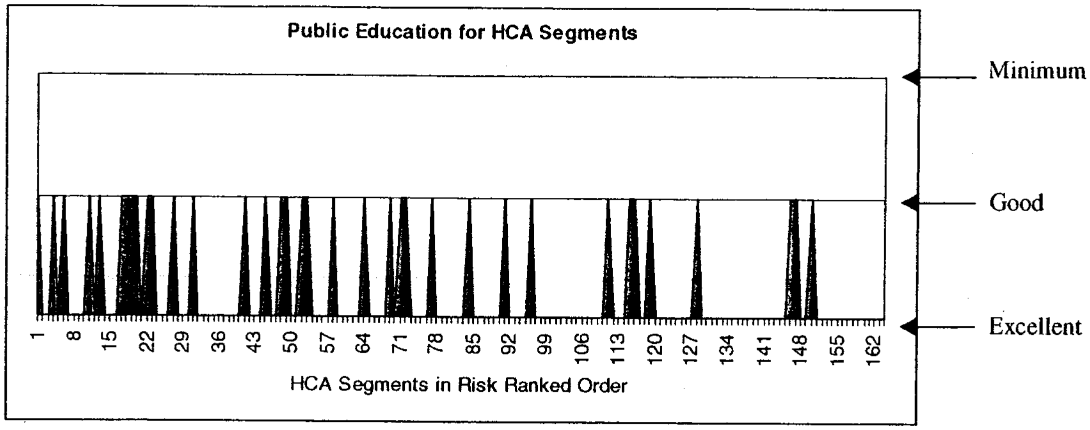
There are 164 Line 3 HCA Segments.

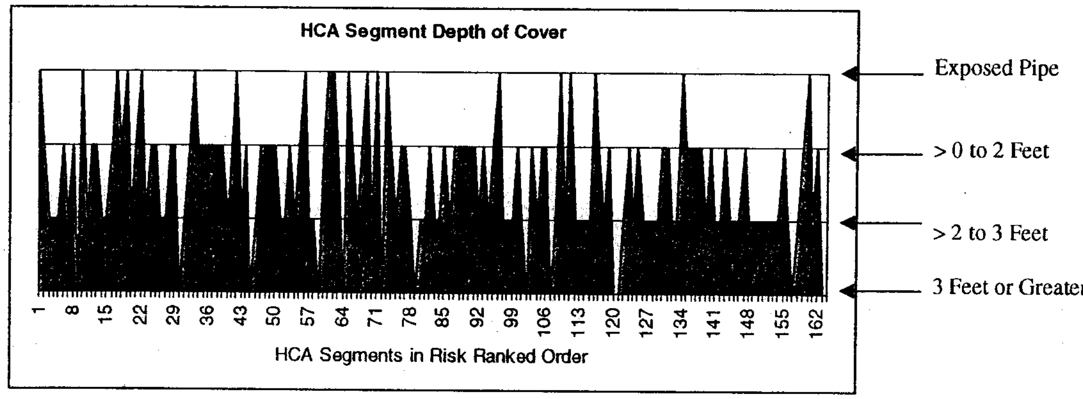
The following diagrams examine the Third Party risk drivers for the Line 3 HCA Segments. Because the stationing is not continuous between the HCA segment locations, the profiles plot the risk drivers on the y-axis and the individual HCA segment risk ranking on the x-axis. Thus the left-most position on the x-axis represents the top-ranked HCA Segment and the right-most position represents the lowest-ranked HCA Segment.

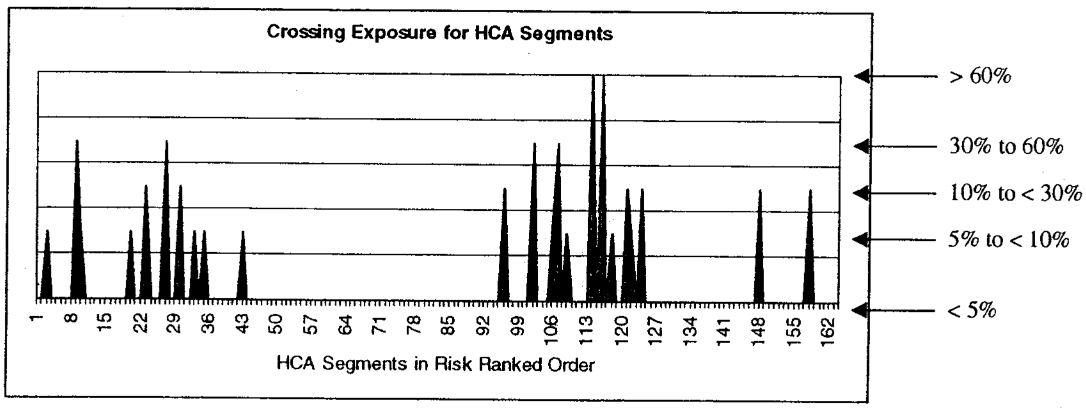
These diagrams are intended to be used as a guide while addressing third party issues as they apply to High Consequence Areas. More detailed and expanded graphs will be used for review and analysis by Region staff during risk control and mitigation discussions.

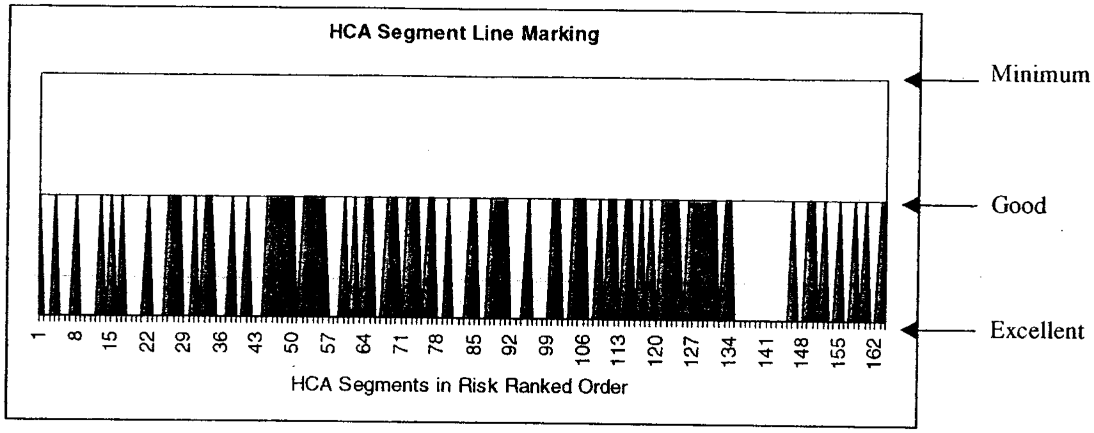




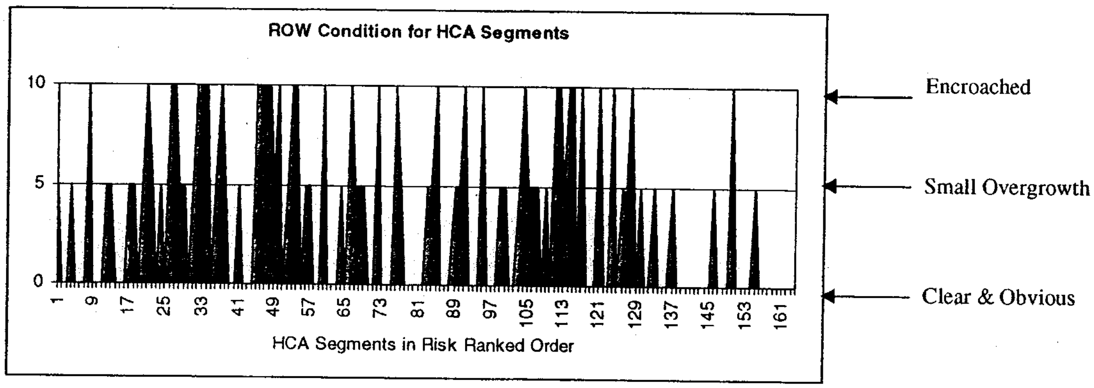

Public Education for HCA Segments
Minimum
Good
Excellent
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
HCA Segments in Risk Ranked Order


HCA Segment Depth of Cover
Exposed Pipe
> 0 to 2 Feet
> 2 to 3 Feet
3 Feet or Greater
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
HCA Segments in Risk Ranked Order

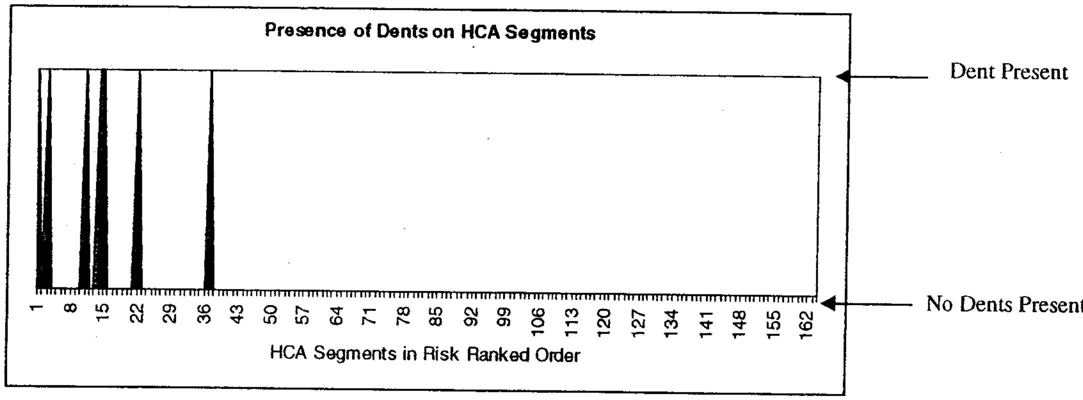

Crossing Exposure for HCA Segments
> 60%
30% to 60%
10% to < 30%
5% to < 10%
< 5%
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
HCA Segments in Risk Ranked Order



HCA Segment Line Marking
Minimum
Good
Excellent
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
HCA Segments in Risk Ranked Order



ROW Condition for HCA Segments
10
5
0
Encroached
Small Overgrowth
Clear & Obvious
1 9 17 25 33 41 49 57 65 73 81 89 97 105 113 121 129 137 145 153 161
HCA Segments in Risk Ranked Order



Presence of Dents on HCA Segments
Dent Present
No Dents Present
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
HCA Segments in Risk Ranked Order

Appendix C

HCA Segment Ground Movement Risk Drivers

This appendix examines the Ground Movement risk drivers for HCA Segments.

The following table outlines the Ground Movement risk drivers for the Line 3 HCA Segments. The list of HCA Segments is incomplete because many of the HCA segments do not have ground movement issues.

Water Crossings	**Start MP**	**End MP**	**Comment**	**HCA Segment Risk Ranking**
Viking to Plummer	863.879	864.7	With Weights and/or Hold Downs	5
Floodwood to Superior	1094.018	1094.887	With Weights and/or Hold Downs	10
Cass Lake to Deer River	984.918	985.652 16+50	With Weights and/or Hold Downs	74
Cass Lake to Deer River	985.652 16+50	985.652 17+50	With Weights and/or Hold Downs	158
Flood Plain Area				
Deer River to Floodwood	993.898 452+38	1005.857		1
Plummer to Clearbrook	885.135 37+00	885.135 51+76		2
Viking to Plummer	863.879	864.7		5
Floodwood to Superior	1096.363	1097.859		7
Plummer to Clearbrook	885.135 27+20	885.135 30+20		9
Floodwood to Superior	1094.018	1094.887		10
Deer River to Floodwood	1010.444	1011.105		11
Plummer to Clearbrook	884.989	885.135 19+95		16
Plummer to Clearbrook	885.135 51+76	886.658		25
Plummer to Clearbrook	885.135 30+20	885.135 37+00		30
Gretna to Donaldson	774.884	776.037		36
Plummer to Clearbrook	885.135 19+95	885.135 27+20		40
Deer River to Floodwood	1022.485	1022.709		91
Deer River to Floodwood	1022.741	1023.512		111
Floodwood to Superior	1093.741	1094.018		120
Deer River to Floodwood	1022.129	1022.485		128
Floodwood to Superior	1046.086	1046.389		140
Deer River to Floodwood	1023.724	1023.982		147
Deer River to Floodwood	1022.709	1022.741		150
High Ground Instability				
Gretna to Donaldson	774.884	776.037		36
Cass Lake to Deer River	984.918	985.652 16+50		74
Cass Lake to Deer River	985.652 16+50	985.652 17+50		158

Appendix D

Emergency Flow Reducing Devices Analysis Example

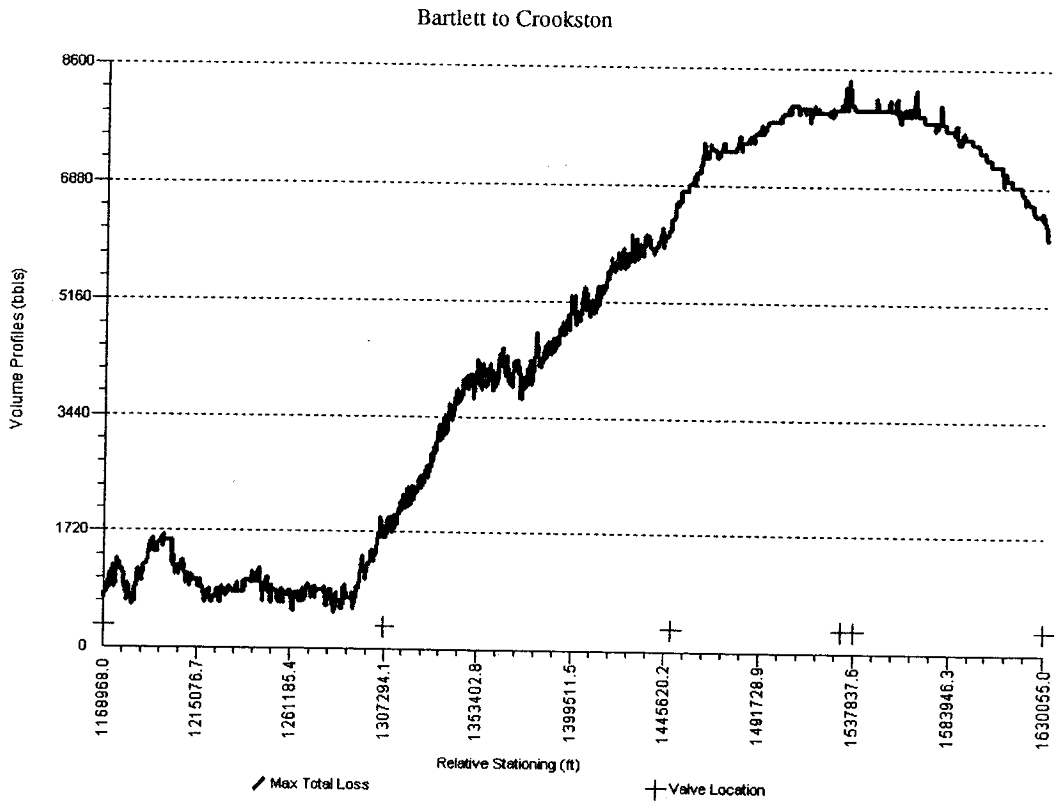
The Integrity Assessment Program (IAP) used by Operational Risk Management to manage data and generate the risk assessment results also has the ability to calculate potential volume out along the pipeline. This calculation considers:

Maximum Capacity / Throughput of the Pipeline	The maximum operating capacity is used for determining the potential volume out.
Location of Remote Controlled Valves	For determining potential rupture volumes, only remote controlled valves are considered as being able to provide isolation.
Elevation Profile	The calculation takes into account variations in the elevation profile.
Pipe Outer Diameter and Wall Thickness	The pipe dimensions are used when calculating draw down / stabilization volumes.
Time to Isolate the Pipeline	The time to recognize a rupture then isolate the pipeline. For Line 3, 8 minutes are required – 5 to detect the rupture, 3 to close the valve.
Type of Rupture	For determining maximum potential volume out, the calculation assumes a rupture with 100% volume out.

The volume out calculation includes the initial volume loss (amount of product released before the rupture site is isolated, i.e. time to isolate the rupture x maximum throughput) and the stabilization (or draw down) loss (the amount of product released after isolation based on the location of the nearest upstream and downstream isolation valves and elevation profile).

An example volume out study is provided in the next pages.

This example is taken from an Enbridge Pipelines (North Dakota) Valve study looking at the upstream side of the Red River Crossing near Grand Forks. The rupture volume profile based on the current operating configuration is as follows:



Valve sites are marked by the plus signs. The profile portrays the total potential volume out – initial volume out + stabilization (or draw down) volume.

The effect of changing an existing valve to remote control is illustrated in the next two figures. Region staff can use similar results as input into their valve placement decision making.

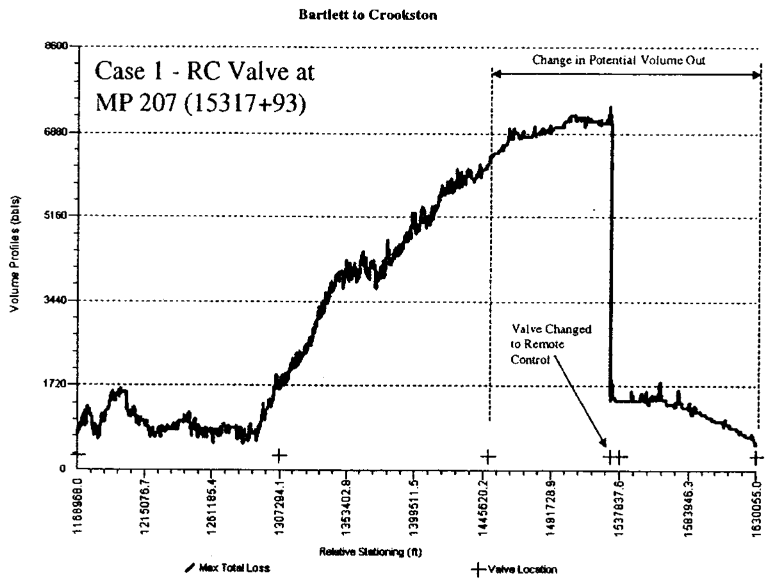
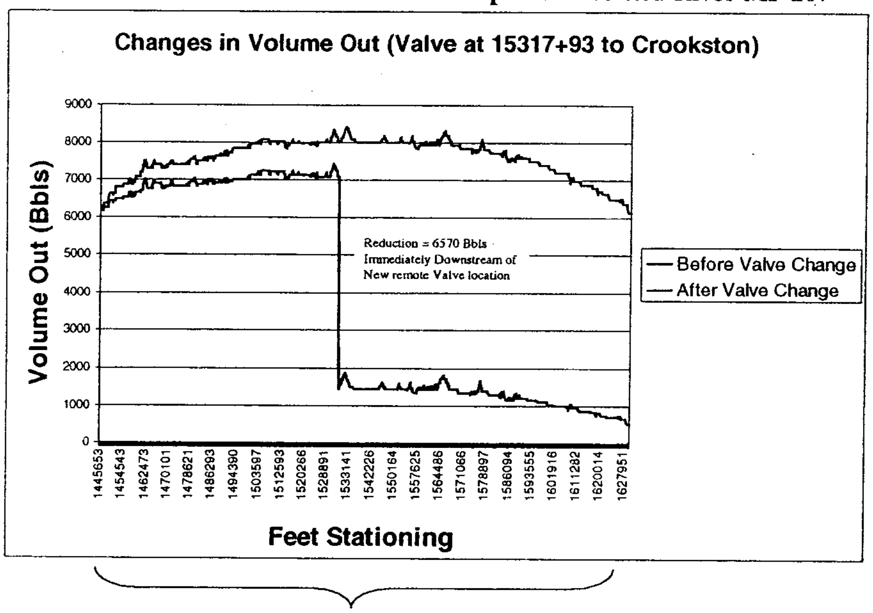


Illustration of Potential Change in Volume Out

Before and After Addition of Remote Operator u/s Red River MP 207



Corresponds to Section Identified in Previous Slide as having Changed Volume Out

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

VIA CERTIFIED MAIL - RETURN RECEIPT REQUESTED

December 9, 2003

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
1100 Louisiana
Suite 2950
Houston, TX 77002-7002

Re: CPF No. 3-2002-5017H
Line 3 - 34-inch Pipeline from US/Canadian Border to Superior, WI
Partial Restoration of Normal Operating Pressure
Approval of Return-to-Service Plan

Dear Mr. Tutcher:

On July 4, 2002, Enbridge's 34-inch pipeline failed near Cohasset, MN, releasing approximately 6,000 barrels of crude oil. On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) requiring Enbridge Energy Company (Enbridge) to establish a return-to-service plan (Plan) for the 34-inch pipeline. Enbridge submitted a Plan for OPS's review on July 8, 2002, and OPS allowed the 34-inch pipeline to return to operation at reduced pressure on July 9, 2002. On July 11, 2002, the Order was amended to cover more 34-inch pipe, and set forth additional requirements for the 34-inch pipeline. On December 2, 2002, OPS approved a modification of the pressure restriction for those pump stations upstream of Clearbrook.

Following submission of the Plan, Enbridge periodically submitted information as required by the Plan and as specifically requested by OPS. Throughout this time Enbridge continued to excavate and repair the 34-inch pipeline based on results of in-line inspections employing crack detection technology. Additionally, OPS and Minnesota Office of Pipeline Safety (MNOPS) staff met periodically with Enbridge representatives in Kansas City, Missouri, to receive progress updates and review the integrity assessment results.

In letters to OPS, dated October 16, 2003 and November 6, 2003, Enbridge indicated that all required repairs associated with seam defects and stress corrosion cracking have been completed on the 34-inch pipeline. Since the configuration of 34-inch pipeline has been modified subsequent to the July 4, 2002 accident, Enbridge performed an analysis to determine base maximum discharge pressures (BMDP) for pump stations on the 34-inch pipeline as indicated in your December 4, 2003 correspondence. Based on our review of the information submitted, including the inspection and repair results, OPS grants an increase in pressure as follows:

> Base Maximum Discharge Pressures for pump stations from Gretna to Clearbrook may be set as proposed in Enbridge's December 4, 2003 letter. These pressures are approximately equivalent to the BMDP's in existence prior to the July 4, 2002 failure, with the exception of Plummer Station. However, in all cases the BMDP's are set such that the established MOP of the pipe downstream of the pump stations is not exceeded during normal operation. Table A below lists the approved allowable settings.

TABLE A - Allowable Base Maximum Discharge Pressures (Gretna to Clearbrook)

Pump Station	Allowable BMDP (psig)
Gretna	698
Donaldson	618
Viking*	686
Plummer	617

*Viking Station was not operational on the 34-inch pipeline at the time of the July 4, 2002 failure; therefore, a discharge pressure was proposed by Enbridge based on the established MOP of the 34" pipe downstream of Viking.

The discharge pressures at pump stations from Clearbrook to Superior shall be set to no more than 90 percent of the discharge pressure at the time of the July 4, 2002 failure, with the exception of Cass Lake Station, as indicated in Table B below. Cass Lake Station's BMDP shall remain at 603 psig.

TABLE B - Allowable Base Maximum Discharge Pressures (Clearbrook to Superior)

Pump Station	Discharge Pressure at Time of Failure	Allowable BMDP (psig)
Clearbrook	703	632
Deer River	663	596
Floodwood	597	537

With OPS's approval of the partial restoration of operating pressure on the 34-inch line, it is no longer necessary to submit a weekly tabulation summarizing occurrences when the base maximum discharge pressure is exceeded, as required by our December 2, 2002 correspondence. However, OPS requests that Enbridge notify OPS by calling the Central Region Office and the Minnesota Office of Pipeline Safety of any and all leaks on the 34-inch pipeline, regardless of size. This request is in addition to notification of the National Response Center and other agencies required by 49 CFR §195 and other applicable regulations.

Per the current return-to-service plan, Enbridge will submit to OPS quarterly reports verifying the validity of the remaining life calculations based on the actual pressure spectrum experienced on the 34-inch pipeline. Based on the timing of the partial restoration of pressure on the 34-inch pipeline permitted by this letter, the first quarterly report should review the actual operating pressure spectrum through March 31, 2004. Along with the quarterly reports please also include a summary report of any integrity actions and results for the 34-inch pipeline, including, but not limited to: repairs, integrity evaluations, integrity assessments such as in-line inspections, and any other tests.

Enbridge has also revised the return-to-service plan as directed by OPS in our September 5, 2003 correspondence. The Plan (revised September 30, 2003) includes actions, such as: in-line inspection of the 34-inch pipeline using crack detection technology, an excavation and repair program following the in-line inspection, and analysis of crack growth on the 34-inch pipeline. Additionally, the Plan contains Enbridge's commitment to use in-line crack detection technology to inspect the Clearbrook to Superior segment in 2005. The Gretna to Clearbrook segment is intended to be inspected using crack detection technology in 2008. Based on our review of the current Plan, the results of the recently completed in-line inspection and repair program, and other actions taken by Enbridge thus far in executing the Plan, OPS approves the Return-to-Service Plan as submitted on October 16, 2003.

Thank you for your continued cooperation. If you have any further questions about this matter, please contact me or my staff.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

cc: Mr. John Sobojinski
Enbridge Pipelines, LLC
119 North 25th Street East
Superior, WI 54880-5247
(via facsimile & US mail)

Mr. Charles Kenow
Minnesota Office of Pipeline Safety
444 Cedar Street
Suite 146-N, Town Square
St. Paul, MN 55101-5147

Enbridge Pipelines (Lakehead) L.L.C.
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Mark J. Willoughby, Manager
U.S. Compliance & Risk Management
Tel 715 394 1534
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ENBRIDGE™

December 9, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby / JH

Mark Willoughby

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 sec	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 sec	Pressure backed up when a Floodwood unit was stopped due to power consumption.
05/19/03	PL	466 psig	5.42%	53 sec	Sediment plugged the Clearbrook transmitter line causing a faulty reading.
09/04/03	GF	448 psi	2.50%	20 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection.
09/04/03	VK	349 psi	5.70%	53 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection. Pressures fluctuated +/- 5psi of MAOP for approximately 20 minutes after the shutdown
09/11/03	VK	349 psi	5.70%	20 sec	Slow acting PCV at Viking Station
09/14/03	MP 1002	435 psi	3.50%	30 sec	Faulty pressure transmitter. We do not believe pressures actually exceeded allowable.
10/03/03	VK	352 psi	6.70%	40 sec	Line shutdown Cromer to Clearbrook for a CR fullstream injection. Settling of line pressures after the shutdown.
10/11/03	GF	455 psi	4.10%	20 sec	Line startup from Cromer to Superior. Pressure exceeded for 1 scan as units were being brought on.
10/12/03	VK	342 psi	3.60%	10 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 10 secs at Viking during the swing.
10/13/03	VK	345 psi	4.50%	40 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 40 secs at Viking during the swing.
10/16/03	VK	339 psi	2.70%	45 sec	Pressure spike at Viking during a non-routine change in line rate. Pressure peaked at 339 psi.
10/20/03	VK	360 psi	9.00%	20 sec	Line startup from Cromer to Superior. Pressure spike as units were brought on line.
10/22/03	VK	350 psi	6.00%	40 sec	During a L3 startup following a L3 Clearbrook injection the discharge pressure at Viking spiked for approx 40 sec when unit 2 failed to start.
10/26/03	VK	341 psi	3.30%	20 sec	L3 startup Cromer to Superior. Pressure over shot discharge setpoint momentarily while bringing units on.
10/26/03	GF	445 psi	1.80%	15 sec	L3 startup Cromer to Superior. Operator dropped a Gretna unit in reaction to pressures at Viking exceeding setpoint causing momentary pressure spike at Gretna

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

Enbridge Pipelines (Lakehead) L.L.C.
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Superior, WI 54880
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U.S. Engineering
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Fax 715 394 1564
john.sobojinski@enbridge.com

ENBRIDGE

December 4, 2003

NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

We have recently discussed the status of the above incident, including Enbridge Energy, Limited Partnership's (Enbridge's) request to slightly modify the Base Maximum Discharge Pressure (BMDP) at seven of the eight locations between Gretna and Floodwood stations. This letter is to confirm and clarify the points of our discussion and to formally present them to the Office of Pipeline Safety (OPS) for consideration and early response.

We would like to emphasize that this request is considered to be part of the incremental increase in operating pressures plan for our 34-inch pipeline, currently being reviewed by the OPS. It is our understanding that this request for changes to BMDPs will not cause any delay in the issuance of the OPS directive, which is expected at any time.

The above incident occurred July 4, 2002, in Cohasset, Minnesota. Since that time, there have been significant changes to Enbridge facilities associated with Line 3. The looped configuration for this section of piping has been eliminated (Terrace Phase III), a new pump station was added, and a new baseline assessment of allowable working pressures (AWPs) was completed. Following is a chart of the affected stations that shows recommended BMDPs, based on the recent operating limits study, and a listing of the pre-incident BMDPs:

Location	Proposed BMDP	Pre-Incident BMDP
Gretna	698	682
Donaldson	618	618
Viking	686	687
Plummer	617	570
Clearbrook	688	683
Cass Lake	612	603
Deer River	618	631
Floodwood	555	547

It should be noted that the proposed BMDP at Clearbrook, Deer River and Floodwood represent 90% of the BMDP that would be selected given the current piping configuration.

A very slight increase in pressure is proposed for most of the above stations, while one location remains the same, and one is to be lowered. Plummer Station, which proposes the largest BMDP increase, was operating at an artificially low BMDP prior to the Cohasset incident. A pressure restriction had been in place for this particular section of pipeline and, although the restriction had been lifted, Enbridge had not reinstated a higher BMDP. Upon review of the recently performed operating limits study for this reconfigured section of line, Plummer Station requires the largest modification.

The incremental return-to-service recommendation, that the OPS has been considering to date, was relevant to the previous configuration of the 34-inch pipe prior to Terrace Phase III. The proposed BMDPs are better suited for the new line configuration that is now in service. Therefore, Enbridge respectfully requests that the OPS agree to the BMDPs as proposed for each of the locations in the above chart. We hope that the OPS will agree that these pressures are appropriate for, and relevant to, the current piping configuration, and that this additional request will not cause any delay in the response expected from the OPS.

We trust that this detailed information accurately captures the information we discussed. However, should you have any concerns, please contact me.

Sincerely,

John R. Sobojinski

John R. Sobojinski

c: David Barrett
David Bryson
John Hayes
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Mark Willoughby

76

Copies to Dave Josh Allan Reg

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ENBRIDGE™

November 21, 2003

NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

Enbridge Energy, Limited Partnership (Enbridge) has reviewed the Office of Pipeline Safety's (OPS) e-mail dated November 3, 2003, requesting additional information. The requested clarifications for the Enbridge submission to OPS on October 16, 2003 have been consolidated in the attached document. Some of these involved typographical errors from previous submissions, and it is our expectation that these minor errors should not negatively impact the evaluation being completed by OPS. The attached information has been thoroughly reviewed for accuracy to help ensure any and all errors have been corrected.

We view submission of this information packet as the final step in the process to begin the staged restoration of pressure on our 34-inch pipeline, and will appreciate a response at your earliest opportunity.

We trust that this detailed information provides complete responses to your queries. Should you require further information, please contact me.

Sincerely,

John R. Sobojinski

Attachment

c: John Hayes
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Mark Willoughby

c/att: Joy Kadnar
H. Noel Duckworth
Brian Pierzina

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #1

In the current return-to-service plan Enbridge states that they intend to run a crack detection tool on the 34-inch pipeline from Gretna to Clearbrook in 2008, but that the schedule may be adjusted based on results of ongoing pipeline integrity analysis. Is it Enbridge's intention that the Gretna to Clearbrook section will be run with a crack detection tool no later than 2008?

Response:

The current Enbridge plan is to conduct a crack in-line inspection between Gretna to Clearbrook in 2008. The reasons for conducting this inspection, approximately four and a half years from present, are described in the response to OPS Question #5 of the September 5, 2003 OPS Information Request package. As described, Enbridge will gather integrity data and conduct crack initiation and growth analyses on an on-going basis. Based on the results of the analyses, the appropriateness of the 2008 timeframe will be reviewed regularly. If the results of engineering analysis indicate benefit to an advanced timeframe or a later timeframe, the plan will be modified accordingly and documented within the Enbridge planning process. This approach is consistent with the plans communicated within the Enbridge High Consequence Area (HCA) Baseline Assessment Schedule – Version 2.0, May 2002. As indicated within the HCA Management Plan, the first UltraScan inspection for this section was conducted in 2001 and additional assessment would be pending outcome of crack susceptibility analysis (also reference the HCA Management Plan "Crack Susceptibility Analysis, Priority Ranking Table"). The Enbridge HCA Baseline Assessment Schedule will be updated to reflect the 2008 plan.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #2 – Bullet 1

Please provide clarification for the following "notch-like" features found in Table 3.1

- *Pipe No.'s 8127 & 9259 (page 1 of 16) are listed as not selected, yet in the comments it appears they are to be excavated. Please explain.*

Response:

The features noted above were not selected and not excavated. The "Notch-Like Disposition Table 3.1", prepared in response to previous OPS information requests, has been corrected and the associated page from the table is attached herein.

The "nl" defects noted above were not selected for excavation on the basis of an engineering assessment. The key assessment considerations were as follows:

a) There were no significant descriptors as defined within the "Notch-like Selection Matrix",
b) shallow size of the defect,
c) features are located 15 and 23 miles downstream of a pump station where the pressure magnitude and pressure cycling is low,
d) excavation trends show low likelihood of significant crack occurrence, and
e) highly conservative parameters within the fitness-for-purpose criteria (assumes low charpy, nominal properties, etc).

The next in-line inspection conducted on this pipeline will serve to identify if additional action is required.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

1

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
GRETNA TO CLEARBROOK																		
02-27546	1740.00	US Steel	347	325	31.99	8.42	62993.22	174	5.80	2.10		bm	e	nl	intermittent; sloping	3	Dig Package	Excavated for the purposes of gathering calibration information.
03-00253	1997.00	US Steel	47	305	14.03	26.40	72712.54	323	1.30	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
03-24913	4317.00	AO Smith	349	285	38.77	0.75	159297.23	350	2.60	2.70	<12.5	aw	i	nl	intermittent; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
04-01045	4745.00	AO Smith	53	295	30.72	8.78	175164.15	180	2.90	0.60		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-05201	4876.00	AO Smith	314	285	3.34	38.18	179741.55	333	2.20	1.20		bm	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-15288	5185.00	AO Smith	329	295	26.51	8.64	191414.78	327	1.80	1.20		lw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
04-15294	5185.00	AO Smith	329	295	27.40	7.75	191415.65	328	2.00	1.50		lw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-02612	6094.00	AO Smith	12	295	33.51	5.95	224921.87	178	3.30	1.50		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-05315	6189.00	AO Smith	40	295	3.80	31.26	228378.01	156	2.10	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-22915	6867.00	AO Smith	13	295	2.13	37.33	253429.37	12	1.40	1.50		lw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-31726	7203.00	AO Smith	348	295	25.30	12.64	266743.76	166	4.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-36954	7413.00	AO Smith	325	295	38.04	1.39	274897.46	158	3.20	1.50		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-41007	7555.00	AO Smith	6	305	37.96	1.44	280186.99	142	4.50	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-05250	7776.00	AO Smith	337	295	24.81	14.60	288219.49	154	3.80	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-08178	7882.00	AO Smith	348	295	30.38	9.04	292225.21	140	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-11092	7973.00	AO Smith	53	295	1.45	37.97	295535.15	63	2.60	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-15235	8127.00	AO Smith	358	285	3.04	19.77	300650.28	2	10.90	0.90	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-15542	8135.00	AO Smith	11	285	33.97	5.22	300980.00	8	0.80	2.40	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-27815	8471.00	AO Smith	323	295	32.94	6.55	313484.19	4	2.10	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-31187	8566.00	AO Smith	331	285	20.03	11.14	317098.53	147	1.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-36282	8704.00	AO Smith	45	295	28.83	10.63	322306.05	46	1.30	2.10	<12.5	aw	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-36858	8721.00	AO Smith	31	295	25.69	13.43	322956.83	30	0.70	1.50	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-01255	8889.00	AO Smith	22	295	36.78	2.68	329211.85	23	3.80	2.40	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-01699	8900.00	AO Smith	305	285	36.31	3.14	329611.54	305	2.10	1.20	<12.5	aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-06100	9013.00	AO Smith	17	295	5.97	23.75	333761.48	178	22.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-13996	9230.00	AO Smith	329	295	22.95	16.48	341894.46	330	1.20	1.50	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-15076	9259.00	AO Smith	26	295	24.67	14.81	343012.73	24	11.30	1.50	<12.5	aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-16998	9303.00	AO Smith	326	295	11.41	28.00	344675.87	326	3.30	2.70	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-17555	9314.00	AO Smith	313	295	20.49	19.00	346098.98	142	1.70	0.90		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

OPS Question #2 – Bullet 2

Please provide clarification for the following "notch-like" features found in Table 3.1

- *Please explain how tool tolerances are considered in the fitness-for-purpose calculations for notch like features. What depth is used when a range is provided by PII? It also appears that some features are near the critical length for the fitness for purpose calculations, for example: pipe no.'s 5902 (p. 6), 10382 (p. 8), 15813 (p.10), and 22935 (p. 14).*

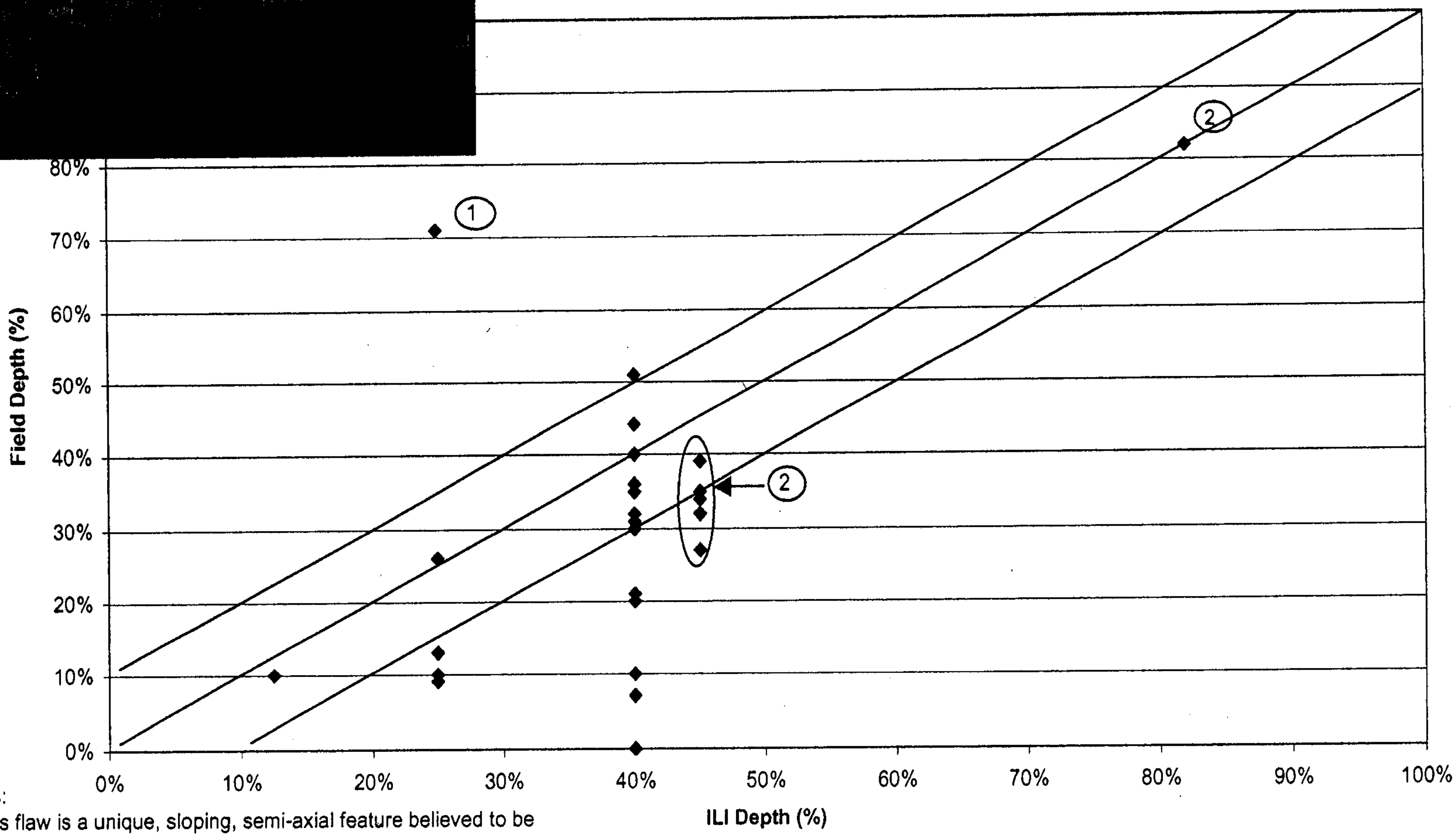
Response:

The UltraScan CD tolerances were established on the basis of field investigation results, trended in comparison to tool analysis data. The trends developed specific to this pipeline were utilized by Enbridge to calibrate the predictions reported by the tool. These calibrated results were then directly incorporated into fitness-for-purpose calculations. The maximum depth was used for the calculations when a range was provided. As shown by Chart 2.1, attached, the calibrated depths estimated by the tool vendor matched, or were conservative in comparison to field results.

Any remaining, unexcavated features are not considered to be at a "critical" length given that they exceed 100% SMYS strength capabilities on the basis of the fitness-for-purpose calculations and engineering analysis. As described in the information package response to the September 5, 2003 OPS queries, of the 183 at-weld/in-weld notch-like features excavated, only 20 required a sleeve. Of these sleeved features, many were repaired based on field decisions that were more conservative than a 100% SMYS target. If there are any remaining features that are not typical benign manufacturing flaws, any growth is expected to occur at a slow rate given their relatively small geometries. In addition, for the defects specifically noted in the query above, all are at least 20 miles from a pump station with low magnitude pressure spectrum exposures.

[redacted]

Clearbrook to Superior
"NL aw or iw" ILI Feature Depths vs. Field Depths



Notes:
1. This flaw is a unique, sloping, semi-axial feature believed to be manufacturing or construction related (see photo).
2. These defects reported by ILI as ">40%" depth.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #2 – Bullet 3

Please provide clarification for the following "notch-like" features found in Table 3.1

- *OPS understands Kaiser pipe is DSAW, and that all notch-like features in or at a USS seam are dug due to possibility of railroad fatigue. Please explain why all notch-like features in or at Kaiser seams are not excavated. Has a representative sample of these features been excavated and determined that railroad fatigue is not an issue on Kaiser pipe?*

Response:

The decision to excavate and assess all at-weld and in-weld notch-like ("nl") features on the US Steel-manufactured pipe was an added precautionary measure. The Kaiser pipe on Line 3 (34") has been in operation for 25 years and in that time it has not experienced a long seam related failure or trend of long seam cracking. The overall integrity of the Kaiser pipe is good and there was no indication that the added precautionary measure was required.

From the UltraScan CD data on Line 3 (34"), three crack-like (cl") features and 15 "aw/iw nl" features were reported on the Kaiser pipe. Two of the "cl" features were found to be raised weld crowns, and the third was a base metal defect that resulted from a rolling lap. Of the 15 "nl" features, 5 were excavated and assessed. 1 feature was reported as a shallow toe crack 10% deep, 2 features were found to be a raised weld crown, and 2 were internal linear indications. As per the representative sample features, the remaining 10 un-excavated "nl" features pass fitness for purpose evaluation and/or are believed to be innocuous defects.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #2 – Bullet 4

Please provide clarification for the following "notch-like" features found in Table 3.1

- *On pipe number 7199 (p. 7 of 16) how was a fitness for purpose calculation performed when no depth information was shown in the table?*

Response:

The Notch-like Disposition Table incorrectly noted that this defect was "not selected." The "nl" defect at GW#7199 was selected for excavation and evaluation on the basis of gathering calibration information (incorrectly noted in the table as "due to fitness for purpose"). As shown on the "Clearbrook to Superior Status Table 1.2" prepared for the OPS in response to the September 5, 2003 information requests, this defect was found to be a short midwall linear indication (likely a lack of fusion) on the AO Smith pipe.

The "Notch-Like Disposition Table 3.1", prepared in response to previous OPS information requests, has been corrected and the associated page from the table is attached, herein.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated (shaded)
Not Excavated

1

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
07-28680	6917.00	AO Smith	333	285	10.97	28.93	263,287.82	148	9.10	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-31338	7007.00	AO Smith	9	285	15.34	24.65	266,685.64	9	1.60	1.80	25-40	aw	nd	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
07-33236	7071.00	AO Smith	314	285	36.63	3.32	269,179.98	132	2.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00130	7113.00	AO Smith	318	295	38.35	1.73	270,816.78	321	2.00	1.20	12.5-25	lw	e	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-00354	7119.00	AO Smith	321	285	1.22	38.76	271,019.55	163	1.40	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00487	7121.00	AO Smith	297	266	35.07	4.83	271,133.32	145	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00613	7125.00	AO Smith	309	295	27.08	12.85	271,277.20	215	2.30	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-01587	7152.00	AO Smith	321	285	31.27	8.71	272,308.81	69	2.80	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-03158	7199.00	AO Smith	321	285	3.31	36.65	274,059.52	321	9.50	1.20		lw	e	nl	probably indication from weld	3	Dig Package	Excavated for the purposes of gathering calibration information.
08-03165	7199.00	AO Smith	321	285	17.53	22.43	274,073.74	318	1.80	2.10	25-40	lw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-04034	7226.00	AO Smith	311	285	7.59	32.39	275,111.02	146	3.20	1.20	25-40	bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-04854	7249.00	AO Smith	21	285	6.33	33.61	276,010.44	229	1.80	1.20	>40	bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-05318	7263.00	AO Smith	12	285	25.31	14.67	276,579.77	12	3.10	1.80	25-40	lw	i	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment.
08-05479	7269.00	AO Smith	9	285	9.73	26.53	276,803.91	8	9.70	2.10	12.5-25	aw	e	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
08-07080	7323.00	AO Smith	21	285	32.84	0.21	278,797.18	19	2.10	1.20	25-40	lw	nd	nl	at GW	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-08614	7378.00	AO Smith	297	285	18.37	4.38	280,661.98	149	2.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-10911	7458.00	AO Smith	16	285	2.42	37.55	283,732.81	165	3.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-14088	7567.00	AO Smith	20	285	20.73	19.18	287,852.09	13	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-14432	7579.00	AO Smith	318	285	20.58	19.37	288,299.37	94	2.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-17231	7677.00	AO Smith	5	285	6.38	33.55	291,932.90	78	4.40	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-17252	7677.00	AO Smith	5	285	28.10	11.83	291,954.62	236	2.50	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-18242	7721.00	AO Smith	269	285	9.59	30.37	293,582.18	65	3.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-18591	7738.00	AO Smith	30	285	6.08	33.92	294,206.41	175	1.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-19616	7778.00	AO Smith	30	295	4.31	35.67	295,742.38	65	2.90	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-20783	7830.00	AO Smith	320	285	27.33	12.64	297,763.63	318	2.30	1.80	25-40	lw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
08-23756	7936.00	AO Smith	318	295	35.79	4.15	301,794.03	143	4.20	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-24240	7953.00	AO Smith	306	266	25.18	14.74	302,420.57	105	2.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-24666	7967.00	AO Smith	57	285	19.46	20.48	302,955.16	56	5.30	2.10		aw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
08-26302	8011.00	AO Smith	294	295	21.97	16.04	304,659.01	296	11.90	1.80	12.5-25	aw	e	nl	intermittent	3	Dig Package	Fails fitness for purpose remaining strength calculation
08-27617	8058.00	AO Smith	144	285	38.31	1.61	306,421.03	144	1.60	2.10		lw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #2 – Bullet 5

Please provide clarification for the following "notch-like" features found in Table 3.1

- *Pipe no's 9364 ad 11652 (p. 8 of 16) are both Kaiser with a notch like feature at weld with an estimated depth range of 25 to 40%. 9364 was selected for excavation and 11652 was not, although the length of 11652 is much longer than 9364. Please explain.*

Response:

The actual ILI reported depth for this feature is <12.5%. The "Notch-Like Disposition Table 3.1", prepared in response to previous OPS information requests, has been corrected to reflect the proper depth estimate for this defect and the associated page from the table is attached, herein. Also attached is the associated UltraScan CD information showing the defect sizing details.

On the basis of an engineering assessment, the "nl" defect at GW#11652 was not selected for excavation. The key assessment considerations were as follows:

a) shallow size of the defect,
b) defect is located 3 miles upstream of a pump station where the pressure magnitude and pressure cycling is low,
c) operating history and excavations show low likelihood of significant crack occurrence, and
d) highly conservative parameters within the fitness-for-purpose criteria (assumes low charpy, nominal properties, etc).

The next in-line inspection conducted on this pipeline will serve to identify if additional action is required.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

	Excavated
	Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
GRETNA TO CLEARBROOK																		
02-27546	1740.00	US Steel	347	325	31.99	8.42	62993.22	174	5.80	2.10		bm	e	nl	intermittent; sloping	3	Dig Package	Excavated for the purposes of gathering calibration information.
03-00253	1997.00	US Steel	47	305	14.03	26.40	72712.54	323	1.30	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
03-24913	4317.00	AO Smith	349	285	38.77	0.75	159297.23	350	2.60	2.70	<12.5	aw	i	nl	intermittent; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
04-01045	4745.00	AO Smith	53	295	30.72	8.78	175164.15	180	2.90	0.60		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-05201	4876.00	AO Smith	314	285	3.34	36.18	179741.55	333	2.20	1.20		bm	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-15288	5185.00	AO Smith	329	295	26.51	8.64	191414.76	327	1.80	1.20		iw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
04-15294	5185.00	AO Smith	329	295	27.40	7.75	191415.65	328	2.00	1.50		iw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-02612	6094.00	AO Smith	12	295	33.51	5.95	224921.87	178	3.30	1.50		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-05315	6189.00	AO Smith	40	295	3.80	31.26	228378.01	156	2.10	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-22915	6857.00	AO Smith	13	295	2.13	37.33	253429.37	12	1.40	1.50		iw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-31726	7203.00	AO Smith	348	295	25.30	12.64	266743.76	166	4.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-36954	7413.00	AO Smith	325	295	38.04	1.39	274897.46	158	3.20	1.50		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-41007	7555.00	AO Smith	6	305	37.96	1.44	280186.99	142	4.50	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-05250	7776.00	AO Smith	337	295	24.81	14.60	288219.49	154	3.80	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-08178	7882.00	AO Smith	348	295	30.38	9.04	292225.21	140	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-11092	7973.00	AO Smith	53	295	1.45	37.97	295535.15	63	2.60	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-15235	8127.00	AO Smith	358	285	3.04	19.77	300650.28	2	10.90	0.90	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-15542	8135.00	AO Smith	11	285	33.97	5.22	300980.00	8	0.80	2.40	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-27815	8471.00	AO Smith	323	295	32.94	6.55	313484.19	4	2.10	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-31187	8566.00	AO Smith	331	285	20.03	11.14	317098.53	147	1.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-36282	8704.00	AO Smith	45	295	28.83	10.63	322306.05	46	1.30	2.10	<12.5	aw	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
06-36858	8721.00	AO Smith	31	295	25.69	13.43	322956.83	30	0.70	1.50	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-01255	8889.00	AO Smith	22	295	36.78	2.68	329211.85	23	3.80	2.40	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-01699	8900.00	AO Smith	305	285	36.31	3.14	329611.54	305	2.10	1.20	<12.5	aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-06100	9013.00	AO Smith	17	295	5.97	23.75	333761.48	178	22.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-13996	9230.00	AO Smith	329	295	22.95	16.48	341894.46	330	1.20	1.50	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-15076	9259.00	AO Smith	26	295	24.67	14.81	343012.73	24	11.30	1.50	<12.5	aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-16998	9303.00	AO Smith	326	295	11.41	28.00	344675.87	326	3.30	2.70	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-17555	9314.00	AO Smith	313	295	20.49	19.00	345098.98	142	1.70	0.90		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-19384	9360.00	AO Smith	341	295	33.16	6.31	346828.20	6	3.30	1.50		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-21564	9447.00	AO Smith	52	285	23.21	16.17	349097.10	52	2.00	1.50	<12.5	aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
08-21406	10675.00	AO Smith	344	285	16.96	22.48	394892.13	347	2.20	1.20	<12.5	aw	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
08-27344	10877.00	AO Smith	355	315	5.02	34.46	401647.34	58	1.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-36090	11118.00	AO Smith	307	315	28.22	11.30	410857.81	213	4.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-04985.	11393.00	AO Smith	53	325	20.84	18.69	421274.87	54	3.80	1.50		aw	i	nl	intermittent; possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
09-05224	11400.00	AO Smith	296	315	30.12	9.39	421554.75	166	1.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-08286	11484.00	AO Smith	326	325	8.88	30.61	424812.88	157	2.10	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-08302	11484.00	AO Smith	326	325	19.47	20.02	424823.47	173	1.50	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-08635	11496.00	AO Smith	279	325	1.09	38.41	425254.79	166	3.30	1.20		bm	e	nl	intermittent; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-10871	11549.00	AO Smith	300	315	34.30	5.18	427236.34	294	2.20	1.50		iw	e	nl	intermittent; possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
09-11505	11562.00	AO Smith	8	315	21.31	8.90	427714.26	9	1.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-14104	11636.00	AO Smith	339	315	10.13	29.36	430452.24	294	2.90	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
09-26110	12027.00	US Steel	340	295	35.86	0.40	444539.04	329	2.20	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-27015	12057.00	US Steel	70	295	5.04	34.41	445643.86	64	19.40	2.40		aw	i	nl	intermittent	3	Dig Package	Additional dig due to US Steel - At Weld
09-35993	12286.00	US Steel	73	285	31.86	8.70	454054.38	61	1.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-37013	12311.00	US Steel	53	285	31.93	7.20	455009.99	111	1.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
10-22797	12948.00	US Steel	81	295	14.80	23.38	479974.02	80	2.00	1.50		aw	e	nl	intermittent	3	Dig Package	Additional dig due to US Steel - At Weld
10-24456	12995.00	US Steel	155	295	7.66	13.20	481783.30	197	4.30	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
10-26212	13034.00	US Steel	337	502	4.99	34.70	483,047.06	336	0.80	1.50		iw	i	nl	weld defect	3	Dig Package	Additional dig due to US Steel - At Weld
10-26244	13034.00	US Steel	337	502	21.99	17.70	483064.06	337	1.80	1.20		iw	e	nl	possibly weld defect	3	Dig Package	Additional dig due to US Steel - At Weld
11-09887	13595.00	AO Smith	27	285	5.22	34.28	504133.46	26	1.40	1.50		aw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
11-12121	13668.00	AO Smith	34	285	23.12	16.35	506871.50	33	2.90	1.20		aw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
11-35607	14370.00	AO Smith	23	285	5.93	33.56	533097.29	22	1.80	1.20		iw	e	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
12-30304	15515.00	AO Smith	339	295	28.16	11.32	575200.08	62	2.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
12-32351	15577.00	AO Smith	336	295	19.02	20.53	577564.85	332	3.70	1.50		iw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
12-32370	15577.00	AO Smith	336	295	28.07	11.48	577573.90	334	2.00	1.20		iw	i	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
12-33570	15615.00	AO Smith	13	295	2.73	36.84	578995.66	152	1.80	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-19497	17202.00	US Steel	22	285	39.16	1.28	639781.87	346	8.80	1.50		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-23015	17287.00	US Steel	75	266	14.86	25.32	642991.39	327	1.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-25431	17346.00	US Steel	341	295	32.69	6.70	645181.38	13	16.60	1.20		bm	e	nl	intermittent; sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-31350	17505.00	US Steel	291	285	23.56	16.83	650895.51	8	1.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-14701	17919.00	AO Smith	360	295	5.14	26.82	666796.86	358	1.60	1.50		iw	e	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
15-15982	17962.00	AO Smith	340	285	16.22	7.18	668109.49	338	1.20	1.50		iw	e	nl	possibly weld defect	3	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
16-02561	18671.00	AO Smith	311	295	25.13	3.60	694677.18	150	7.60	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-02559	18671.00	AO Smith	311	295	26.84	1.89	694678.89	150	1.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-20302	19144.00	AO Smith	48	285	0.40	38.86	712136.65	60	3.80	1.80		bm	e	nl	intermittent; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-24670	19275.00	AO Smith	36	295	1.34	35.36	717049.15	306	2.30	1.50		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

CLEARBROOK TO SUPERIOR

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
01-00187	3.00	AO Smith	66	374	22.58	14.97	148.84	157	5.20	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
01-31052	33.00	US Steel	78	374	16.24	24.73	774.41	274	10.70	2.70		bm	e	nl	sloping	3	Dig Package	Adj. To Primary Feature
01-01057	33.00	US Steel	78	374	24.41	16.56	782.58	67	4.70	1.20	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
01-01390	40.00	US Steel	303	374	38.34	2.63	1,072.88	300	8.00	3.00	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
01-23596	481.00	US Steel	360	354	31.01	10.01	18,491.43	14	5.60	3.30		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
01-23641	483.00	US Steel	276	354	4.64	36.35	18,546.79	261	1.70	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
01-31380	487.00	US Steel	21	325	15.05	25.64	18,720.85	242	43.80	2.70		bm	e	nl	curved	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
01-24962	510.00	US Steel	36	354	11.57	29.43	19,655.37	358	10.00	2.70		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
01-28778	601.00	US Steel	9	354	8.00	32.92	23,249.88	6	1.50	2.10	12.5-25	iw	nd	nl		3	Dig Package	Additional dig due to US Steel - At Weld
01-29141	609.00	US Steel	354	325	40.06	0.84	23,606.36	334	2.00	1.20		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-02985	720.00	US Steel	327	344	14.79	26.21	27,849.35	322	3.20	2.10	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
02-05712	785.00	US Steel	282	354	32.83	7.47	30,470.48	282	3.20	1.20	12.5-25	iw	nd	nl		3	Dig Package	Additional dig due to US Steel - At Weld
02-12034	931.00	US Steel	306	344	6.89	34.04	36,180.55	274	9.90	1.50		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-12193	935.00	US Steel	288	364	27.76	11.77	36,365.08	247	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-13448	966.00	US Steel	18	344	25.37	15.57	37,607.44	45	7.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-15334	1018.00	US Steel	108	344	23.39	17.55	39,396.92	108	5.40	2.10	<12.5	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
02-19427	1117.00	US Steel	312	344	19.98	21.02	43,235.13	269	6.00	1.80		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-19611	1122.00	US Steel	261	344	35.95	4.95	43,419.08	59	6.80	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-21718	1176.00	US Steel	270	315	37.73	2.35	45,587.36	298	7.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-27745	1184.00	US Steel	309	315	31.28	9.70	45,852.41	38	3.10	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-22367	1187.00	US Steel	309	315	11.45	1.21	45,955.26	6	2.50	0.90		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-23523	1211.00	US Steel	267	315	12.96	28.04	46,881.05	298	16.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-25669	1270.00	US Steel	279	315	3.90	37.08	49,214.51	150	1.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
02-27061	1302.00	US Steel	255	315	21.76	19.20	50,516.61	148	2.50	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
03-13470	1646.00	US Steel	270	315	2.77	38.23	63,691.51	270	1.70	2.10		iw	e	nl	possibly weld defect	2	Dig Package	Additional dig due to US Steel - At Weld
03-15363	1689.00	US Steel	348	315	31.00	9.25	65,465.83	74	5.50	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
03-22441	1880.00	US Steel	267	315	40.38	0.56	72,976.75	146	3.90	1.50		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
03-25576	1963.00	US Steel	342	315	25.72	15.22	76,208.73	125	9.10	1.80		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-00086	2115.00	US Steel	27	315	0.92	39.50	82,304.05	119	2.70	1.20		bm	e	nl	sloping: near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-05078	2248.00	US Steel	3	315	0.89	37.11	87,635.13	134	3.40	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-43048	2800.00	US Steel	21	285	4.46	36.49	110,132.42	8	8.90	1.50	25-40	aw	i	nl	sloping	3	Dig Package	Additional dig due to US Steel - At Weld
04-27689	2802.00	US Steel	18	285	16.74	24.20	110,226.54	8	9.90	2.40		aw	e	nl	sloping	3	Dig Package	Additional dig due to US Steel - At Weld
04-28048	2808.00	US Steel	72	285	4.39	34.70	110,458.31	147	2.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
04-43057	3151.00	US Steel	327	285	8.96	32.01	123,274.69	324	10.70	2.40	25-40	aw	e	nl	intermittent	3	Dig Package	Additional dig due to US Steel - At Weld
04-42797	3192.00	US Steel	348	285	9.74	31.28	124,644.70	241	1.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-02003	3254.00	US Steel	46	285	11.43	27.54	126,997.69	151	2.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-02011	3254.00	US Steel	46	285	14.17	24.80	127,000.43	126	1.90	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-02010	3254.00	US Steel	46	285	14.94	24.03	127,001.20	101	2.80	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-02019	3254.00	US Steel	46	285	17.37	21.60	127,003.63	342	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-02930	3282.00	US Steel	333	285	25.32	7.37	128,022.12	330	4.60	1.20	25-40	iw	e	nl	possibly weld defect; strong	1	Dig Package	Additional dig due to US Steel - At Weld
05-03417	3296.00	US Steel	316	285	4.95	9.26	128,497.86	318	2.30	2.10		iw	nd	nl	possibly weld defect; 20.02.03; OD Crack, 50% depth	2	Dig Package	Additional dig due to US Steel - At Weld
05-03521	3303.00	AO Smith	69	295	9.03	30.90	128,580.06	162	4.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-06860	3405.00	AO Smith	33	295	2.17	37.84	132,405.86	29	1.40	1.80		iw	e	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-07689	3432.00	AO Smith	297	295	12.16	27.85	133,476.88	273	3.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-09600	3499.00	AO Smith	21	295	37.09	2.85	136,049.14	351	3.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-13511	3635.00	AO Smith	84	295	35.21	4.78	141,145.67	39	3.20	1.20		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-16088	3724.00	AO Smith	327	285	37.58	2.43	144,525.80	326	2.10	1.80	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
05-16485	3740.00	AO Smith	318	285	8.14	31.85	145,077.37	281	4.70	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-16521	3741.00	AO Smith	16	285	10.68	29.29	145,119.90	198	9.10	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-18909	3810.00	AO Smith	292	295	1.11	37.82	147,780.51	289	2.30	1.80	12.5-25	iw	i	nl	near GW, (possibly weld defect)	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
05-23505	3953.00	AO Smith	321	295	1.40	38.57	153,260.87	318	1.40	1.80		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
05-28198	4094.00	AO Smith	87	285	39.78	0.18	158,568.38	138	2.30	1.80		bm	i	nl	across GW; sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-28353	4098.00	AO Smith	112	295	1.58	33.47	158,690.00	111	2.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-28797	4110.00	AO Smith	351	295	4.55	35.42	159,102.73	250	6.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-28853	4111.00	AO Smith	297	295	36.82	3.14	159,174.97	294	1.20	0.90		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
05-28858	4112.00	AO Smith	39	295	2.34	37.63	159,180.45	35	6.20	1.20		iw	nd	nl	possibly weld defect; 20.02.03; ID Gouge adj to LW, <10% depth	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-30190	4162.00	AO Smith	289	295	26.30	13.67	160,798.01	105	4.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-32743	4257.00	AO Smith	75	285	2.99	37.05	163,694.08	25	2.60	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-33333	4270.00	AO Smith	267	295	28.99	11.02	164,239.82	146	4.40	1.20		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-33412	4272.00	AO Smith	78	295	10.52	29.46	164,301.33	80	4.10	1.80		iw	nd	nl	possibly weld defect; 20.02.03; IDCrack, 30% depth	1	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
05-36702	4372.00	AO Smith	36	285	28.90	3.88	167,996.53	123	2.60	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-44411	4397.00	AO Smith	25	285	37.60	2.74	168,934.43	322	3.20	1.80		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-38648	4424.00	AO Smith	66	285	7.51	32.56	169,937.39	144	4.50	2.10		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-41348	4526.00	AO Smith	292	295	39.00	1.02	173,497.86	354	2.60	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
05-42832	4565.00	AO Smith	33	285	38.28	1.74	175,031.03	33	1.90	1.80		aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
05-43722	4595.00	AO Smith	96	295	11.72	28.23	176,138.56	108	1.30	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-42308	4619.00	AO Smith	39	285	7.87	32.08	177,079.08	125	5.20	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-00399	4621.00	AO Smith	6	285	22.62	17.36	177,173.78	189	7.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-00755	4630.00	AO Smith	267	285	16.18	23.79	177,527.24	79	2.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-00775	4631.00	AO Smith	75	295	4.93	35.12	177,555.96	145	2.20	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-02355	4674.00	AO Smith	316	285	11.00	29.01	179,231.94	133	12.10	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
06-02835	4688.00	AO Smith	327	285	19.25	20.72	179,745.86	145	4.30	2.40		bm	i	nl		2	Dig Package	Excavated for the purposes of gathering calibration information.
06-02988	4692.00	AO Smith	105	285	2.03	37.94	179,888.87	98	2.20	1.20	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
06-07727	4822.00	AO Smith	279	295	16.58	23.42	184,657.76	278	5.30	1.20		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-09109	4875.00	AO Smith	24	295	12.38	27.63	186,509.69	146	2.00	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-12321	4983.00	AO Smith	262	295	20.41	19.48	190,636.77	58	4.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-13590	5019.00	AO Smith	336	295	22.73	17.26	192,060.59	261	5.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-13594	5019.00	AO Smith	336	295	24.03	15.96	192,061.89	160	3.00	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-15338	5066.00	AO Smith	33	285	28.99	10.91	193,899.94	123	3.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-16944	5118.00	AO Smith	8	285	15.69	24.22	195,900.27	6	3.40	1.20		aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
06-18436	5165.00	AO Smith	42	285	1.32	38.62	197,682.19	133	4.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-20160	5211.00	AO Smith	39	295	32.50	7.38	199,483.00	38	2.70	1.20	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
06-21614	5253.00	AO Smith	19	295	1.05	38.87	201,078.57	330	2.70	1.80		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-25961	5398.00	AO Smith	333	285	11.39	6.25	206,765.86	54	3.40	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-29310	5492.00	AO Smith	324	295	12.08	28.02	210,407.90	138	2.80	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-29348	5492.00	AO Smith	324	295	32.24	7.86	210,428.06	72	2.40	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-32060	5580.00	AO Smith	258	295	0.13	39.85	213,687.86	118	8.20	1.20		bm	e	nl	at GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-32352	5588.00	AO Smith	312	295	39.00	0.94	214,046.30	129	2.50	1.80		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-33752	5629.00	AO Smith	27	295	22.13	17.81	215,661.46	135	2.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-35805	5697.00	AO Smith	321	295	0.07	39.88	217,922.05	280	3.00	0.90		bm	e	nl	at GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-37641	5757.00	AO Smith	285	295	1.31	38.68	220,251.74	124	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-37888	5763.00	AO Smith	285	295	30.50	9.49	220,520.71	26	4.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
06-38056	5769.00	AO Smith	39	295	16.32	23.59	220,734.67	204	2.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-38161	5771.00	AO Smith	339	285	28.66	11.31	220,826.91	343	4.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
06-42228	5902.00	AO Smith	9	295	6.67	33.36	225,757.12	9	3.90	2.40	25-40	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
07-01655	5958.00	AO Smith	81	295	32.53	7.47	227,873.43	80	4.00	2.10		aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
07-02690	5988.00	AO Smith	297	285	14.99	24.84	229,030.90	126	4.00	1.50		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-06059	6103.00	AO Smith	318	285	20.27	19.63	233,023.21	314	1.70	1.80	12.5-25	aw	nd	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
07-08863	6199.00	AO Smith	13	295	3.83	36.13	236,760.80	164	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-08870	6199.00	AO Smith	13	295	6.98	32.98	236,763.95	152	5.40	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-08873	6199.00	AO Smith	13	295	10.06	29.90	236,767.03	165	3.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-08887	6199.00	AO Smith	13	295	19.86	20.10	236,776.83	167	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-09731	6231.00	AO Smith	21	285	30.87	9.06	238,060.37	20	6.30	2.10	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
07-10296	6252.00	AO Smith	57	295	39.26	0.69	238,801.64	55	5.90	2.40	12.5-25	aw	nd	nl	curved; near GW	3	Dig Package	Fails fitness for purpose remaining strength calculation
07-11949	6315.00	AO Smith	87	285	4.27	35.73	241,078.60	84	3.00	1.80	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
07-12222	6323.00	AO Smith	48	295	32.50	7.65	241,417.43	46	3.50	1.80	25-40	iw	i	nl	possibly weld defect; strong	1	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment - CUTOUT.
07-13760	6378.00	AO Smith	27	295	20.97	18.94	243,259.15	320	5.20	1.80		bm	i	nl	curved	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-34347	6444.00	AO Smith	321	285	1.57	28.23	245,583.16	63	47.60	1.80		bm	nd	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-16205	6465.00	AO Smith	318	285	37.17	2.78	246,323.58	126	3.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-18045	6536.00	AO Smith	303	285	33.83	5.61	248,847.89	300	2.00	2.10	12.5-25	aw	e	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
07-22129	6690.00	AO Smith	314	285	10.92	28.95	254,796.66	354	1.60	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-22748	6708.00	AO Smith	315	285	33.88	6.08	255,538.40	314	10.40	3.00	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
07-26107	6830.00	AO Smith	256	285	33.37	6.50	259,984.85	125	2.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-26686	6851.00	AO Smith	321	285	19.59	20.33	260,762.12	7	2.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-26948	6860.00	AO Smith	324	285	30.02	9.90	261,114.35	324	1.00	2.40		iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
07-27788	6890.00	AO Smith	313	285	39.38	0.60	262,276.91	271	3.50	1.20		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-28078	6899.00	AO Smith	19	285	35.46	4.44	262,609.33	123	2.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-28510	6912.00	AO Smith	8	285	18.62	21.24	263,095.93	145	2.60	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-28680	6917.00	AO Smith	333	285	10.97	28.93	263,287.82	148	9.10	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
07-31338	7007.00	AO Smith	9	285	15.34	24.65	266,685.64	9	1.60	1.80	25-40	aw	nd	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
07-33236	7071.00	AO Smith	314	285	36.63	3.32	269,179.98	132	2.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00130	7113.00	AO Smith	318	295	38.35	1.73	270,816.78	321	2.00	1.20	12.5-25	iw	e	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-00354	7119.00	AO Smith	321	285	1.22	38.76	271,019.55	163	1.40	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00487	7121.00	AO Smith	297	266	35.07	4.83	271,133.32	145	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-00613	7125.00	AO Smith	309	295	27.08	12.85	271,277.20	215	2.30	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-01587	7152.00	AO Smith	321	285	31.27	8.71	272,308.81	69	2.80	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-03158	7199.00	AO Smith	321	285	3.31	36.65	274,059.52	321	9.50	1.20		iw	e	nl	probably indication from weld	3	Dig Package	Excavated for the purposes of gathering calibration information.
08-03165	7199.00	AO Smith	321	285	17.53	22.43	274,073.74	318	1.80	2.10	25-40	iw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-04034	7226.00	AO Smith	311	285	7.59	32.39	275,111.02	146	3.20	1.20	25-40	bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-04854	7249.00	AO Smith	21	285	6.33	33.61	276,010.44	229	1.80	1.20	>40	bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-05318	7263.00	AO Smith	12	285	25.31	14.67	276,579.77	12	3.10	1.80	25-40	iw	i	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
08-05479	7269.00	AO Smith	9	285	9.73	26.53	276,803.91	8	9.70	2.10	12.5-25	aw	e	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
08-07080	7323.00	AO Smith	21	285	32.84	0.21	278,797.18	19	2.10	1.20	25-40	iw	nd	nl	at GW	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
08-08614	7378.00	AO Smith	297	285	18.37	4.38	280,661.98	149	2.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-10911	7458.00	AO Smith	15	285	2.42	37.55	283,732.81	165	3.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-14088	7567.00	AO Smith	20	285	20.73	19.18	287,852.09	13	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-14432	7579.00	AO Smith	318	285	20.58	19.37	288,299.37	94	2.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-17231	7677.00	AO Smith	5	285	6.38	33.55	291,932.90	78	4.40	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
08-17252	7677.00	AO Smith	5	285	28.10	11.83	291,954.62	236	2.50	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-18242	7721.00	AO Smith	289	285	9.59	30.37	293,582.18	65	3.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-18591	7738.00	AO Smith	30	285	6.08	33.92	294,206.41	175	1.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-19616	7778.00	AO Smith	30	295	4.31	35.67	295,742.38	65	2.90	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-20783	7830.00	AO Smith	320	285	27.33	12.64	297,763.63	318	2.30	1.80	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
08-23756	7936.00	AO Smith	318	295	35.79	4.15	301,794.03	143	4.20	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-24240	7953.00	AO Smith	306	266	25.18	14.74	302,420.57	105	2.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
08-24666	7967.00	AO Smith	57	285	19.46	20.48	302,955.16	56	5.30	2.10		aw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
08-26302	8011.00	AO Smith	294	295	21.97	16.04	304,659.01	296	11.90	1.80	12.5-25	aw	e	nl	intermittent	3	Dig Package	Fails fitness for purpose remaining strength calculation
08-27617	8058.00	AO Smith	144	285	38.31	1.61	306,421.03	144	1.60	2.10		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
08-31152	8180.00	AO Smith	262	295	10.12	29.79	311,025.57	264	10.20	2.40	12.5-25	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
08-31365	8187.00	AO Smith	102	285	25.21	14.70	311,320.19	99	13.00	2.40	12.5-25	aw	e	nl	intermittent	3	Dig Package	Fails fitness for purpose remaining strength calculation
09-00524	8279.00	AO Smith	75	285	7.90	12.24	314,792.98	76	1.40	1.80		iw	e	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
09-02235	8337.00	AO Smith	24	285	18.75	19.02	317,048.02	147	1.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-03372	8376.00	AO Smith	21	295	12.30	27.67	318,548.91	20	1.60	2.10		iw	i	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
09-04199	8404.00	AO Smith	12	295	21.57	18.37	319,634.83	147	2.60	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-04501	8415.00	AO Smith	273	295	19.68	20.25	320,058.02	267	2.80	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-06207	8472.00	AO Smith	69	295	30.32	9.66	322,239.38	235	1.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
09-09204	8575.00	AO Smith	22	285	19.64	20.28	326,163.51	18	11.40	2.10	12.5-25	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
09-27984	9189.00	Kaiser	351	285	27.48	12.63	349,342.53	13	2.00	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
10-01557	9324.00	Kaiser	297	285	12.36	26.91	354,578.09	293	2.50	1.20		aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
10-02667	9364.00	Kaiser	18	285	0.40	39.76	356,102.84	16	4.60	3.00	25-40	aw	i	nl	near GW	3	Dig Package	Fails fitness for purpose remaining strength calculation
10-14975	9747.00	Kaiser	324	285	1.62	38.52	370,704.71	270	1.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																EXCAVATION PROGRAM			
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
10-16438	9800.00	Kaiser	357	295	4.18	18.17	372,710.00	158	16.10	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
10-20832	9941.00	Kaiser	327	285	6.87	16.97	378,330.54	324	3.20	2.40	25-40	iw	nd	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
10-30334	9953.00	Kaiser	315	285	26.03	14.07	378,812.30	312	52.60	3.30	25-40	aw	e	nl	sloping	3	Dig Package	Fails fitness for purpose remaining strength calculation
10-21828	9973.00	Kaiser	351	295	36.28	3.86	379,621.90	216	1.60	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
10-30337	9982.00	Kaiser	354	295	37.26	2.91	379,982.58	354	11.20	2.10	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
11-03608	10325.00	Kaiser	354	285	1.02	39.14	393,512.04	167	3.50	1.20		bm	e	nl	strong; near GW	2	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
11-26776	10382.00	Kaiser	330	285	36.99	2.22	395,770.58	327	5.10	2.40	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
11-12789	10655.40	Kaiser	18	778	0.08	1.45	405,954.14	18	3.80	3.30		aw	e	nl	strong; at GW; possibly indication from weld	2	Not Selected	Does Not Meet Dig Selection Criteria - likely weld profile indication
11-12942	10660.00	Kaiser	324	285	14.70	25.48	406,129.35	316	5.00	0.90		aw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
11-16096	10754.00	Kaiser	12	285	13.87	25.95	409,844.76	9	2.60	2.40	25-40	iw	e	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
11-21585	10925.00	Kaiser	330	295	16.43	23.69	416,356.96	326	7.90	1.80		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
11-26081	11098.00	Kaiser	24	285	0.73	39.36	422,864.76	20	4.70	3.00	12.5-25	aw	i	nl	near GW	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
12-01183	11175.00	Kaiser	309	295	25.07	15.11	425,620.59	305	3.20	2.40	25-40	iw	e	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
12-12234	11604.00	Kaiser	321	295	3.88	14.36	441,969.14	348	2.30	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
12-12305	11608.00	Kaiser	315	295	8.48	31.49	442,112.16	311	3.90	3.00	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
12-13483	11652.00	Kaiser	321	295	0.26	39.50	443,826.79	322	16.00	2.10	<12.5	aw	i	nl	curved; near GW	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
12-13727	11658.00	Kaiser	327	295	31.28	8.87	444,093.93	149	2.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
12-19205	11858.00	Kaiser	300	295	35.09	4.94	451,737.73	119	2.80	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-05057	12195.00	US Steel	75	354	24.54	16.21	462,877.91	4	4.80	0.90		bm	e	nl	sloping	3	Dig Package	Adj. To Primary Feature
13-06477	12223.00	US Steel	6	354	0.64	40.16	463,976.43	165	26.00	1.20		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-07987	12251.00	US Steel	252	344	19.02	21.74	465,080.91	145	3.50	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-07989	12251.00	US Steel	252	344	20.16	20.60	465,082.05	146	3.60	0.90		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-11426	12326.00	US Steel	21	344	35.48	5.34	468,131.40	234	4.40	0.90		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-12180	12342.00	US Steel	6	344	4.07	36.78	468,752.50	67	1.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
13-13659	12369.00	US Steel	312	344	40.09	0.79	469,874.46	145	9.10	1.20		bm	i	nl	at GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-17333	12445.00	US Steel	342	344	7.64	30.62	472,885.74	145	17.30	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-36049	12554.00	US Steel	360	344	4.25	36.53	477,209.60	5	12.90	1.20	25-40	aw	i	nl		3	Dig Package	Additional dig due to US Steel - At Weld
13-23002	12557.00	US Steel	330	344	9.91	30.44	477,337.54	294	6.90	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-24228	12585.00	US Steel	330	305	17.23	23.60	478,366.64	159	3.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-29725	12696.00	US Steel	21	315	32.88	7.98	482,740.86	38	3.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
13-31305	12730.00	US Steel	312	354	3.19	36.98	483,960.34	125	16.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-00581	12826.00	US Steel	27	315	36.78	3.52	487,564.15	69	1.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-01547	12844.00	US Steel	33	305	6.44	32.70	488,228.69	90	3.20	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-02791	12869.00	US Steel	345	315	17.23	23.18	489,210.53	297	3.40	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-03014	12873.00	US Steel	249	315	13.13	27.68	489,369.35	231	21.90	1.20		bm	e	nl		3	Dig Package	Adj. To Primary Feature
14-03027	12873.00	US Steel	249	315	16.67	24.14	489,372.89	231	7.00	1.20		bm	e	nl		3	Dig Package	Adj. To Primary Feature
14-03031	12873.00	US Steel	249	315	20.14	20.67	489,376.36	234	5.00	1.50	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
14-05377	12920.00	US Steel	186	305	0.77	40.07	491,244.91	225	2.40	1.80		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-06512	12941.00	US Steel	126	315	38.60	1.76	492,134.92	124	4.20	2.10	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
14-07274	12956.00	US Steel	87	315	26.26	14.57	492,729.49	84	2.60	2.10		aw	e	nl	striking; 20.02.03; Toe Crack, 41% depth	2	Dig Package	Additional dig due to US Steel - At Weld
14-39126	13049.00	US Steel	51	315	0.39	39.05	496,222.04	110	7.10	1.50		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
14-15946	13153.00	US Steel	303	325	0.39	25.66	500,227.94	299	3.30	2.40		bm	e	nl	near GW	3	Dig Package	Adj. To Primary Feature
14-15944	13153.00	US Steel	303	325	2.13	23.92	500,229.68	299	1.90	2.40	<12.5	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
14-23805	13314.00	US Steel	357	315	3.51	37.25	506,560.83	354	20.50	3.00	25-40	aw	nd	nl	curved	3	Dig Package	Additional dig due to US Steel - At Weld
14-31021	13462.00	US Steel	321	315	38.29	1.84	512,486.43	305	5.20	1.20		aw	e	nl	sloping	3	Dig Package	Additional dig due to US Steel - At Weld
14-37025	13595.00	US Steel	24	305	35.12	5.69	517,341.06	322	8.90	0.90		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-07734	13831.00	US Steel	45	295	3.04	37.72	526,256.87	40	3.10	2.10		aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
15-11057	13911.00	US Steel	327	295	15.79	25.05	529,380.09	217	1.80	0.60		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-12074	13937.00	US Steel	273	295	19.60	21.23	530,293.87	246	1.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-18575	14088.00	US Steel	21	492	31.65	9.11	535,632.14	334	5.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-20235	14131.00	US Steel	3	305	13.21	3.89	537,212.53	146	1.60	1.50		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-25679	14272.00	US Steel	312	295	23.17	17.58	542,244.69	138	1.50	1.50		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

	Excavated
	Not Excavated

IN-LINE INSPECTION																EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
15-34522	14288.00	US Steel	252	295	14.11	8.39	542,760.31	14	40.30	1.80		bm	e	nl	intermittent; curved	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-26768	14299.00	US Steel	18	295	14.57	26.18	543,113.63	124	2.30	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-30474	14394.00	US Steel	24	295	18.38	21.71	546,886.53	182	7.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
15-32966	14454.00	US Steel	357	295	7.09	33.67	549,202.41	244	2.30	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-00664	14502.00	US Steel	315	295	26.95	13.77	550,946.84	109	4.70	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-02747	14549.00	US Steel	84	295	22.27	18.53	552,761.50	81	10.20	2.40	25-40	aw	i	nl		3	Dig Package	Additional dig due to US Steel - At Weld
16-04629	14602.00	US Steel	306	285	5.65	34.45	554,692.31	303	1.80	2.40		iw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
16-07136	14659.00	US Steel	3	285	11.53	29.31	556,921.76	150	1.70	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-23536	15086.00	AO Smith	335	295	23.01	16.69	573,356.76	81	2.50	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-24632	15122.00	AO Smith	10	266	17.86	5.99	574,746.04	8	1.50	1.80	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
16-26534	15184.00	AO Smith	330	295	25.41	14.39	577,146.96	328	1.80	2.10	25-40	iw	i	nl	possibly weld defect; striking	1	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
16-27319	15211.00	AO Smith	84	295	4.15	35.70	578,140.48	35	3.90	1.20		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-31030	15332.00	AO Smith	314	295	35.23	4.62	582,697.32	312	1.90	1.80	12.5-25	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
16-31790	15363.00	AO Smith	345	266	31.37	8.49	583,565.09	247	2.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
16-32481	15392.00	AO Smith	318	295	11.85	28.00	584,576.42	316	1.70	2.10	25-40	iw	e	nl		2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-00522	15411.00	AO Smith	302	285	33.38	6.44	585,290.51	338	2.90	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-00687	15417.00	AO Smith	306	295	22.18	1.22	585,515.97	125	2.40	1.20		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-06653	15606.00	AO Smith	330	285	36.34	3.49	592,749.47	138	3.30	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-06732	15609.00	AO Smith	27	285	39.08	0.73	592,867.00	38	3.50	0.90		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-06898	15615.00	AO Smith	27	285	19.43	15.08	593,085.88	24	1.90	1.80	>40	iw	i	nl	possibly weld defect; strong	1	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
17-08233	15662.00	AO Smith	27	285	18.32	21.54	594,866.93	266	4.30	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-08334	15666.00	AO Smith	333	285	6.17	33.63	595,013.92	146	23.00	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-08343	15666.00	AO Smith	333	285	8.09	31.71	595,015.84	146	22.60	1.20		bm	e	nl	continuation of area 17-08334	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
17-10071	15727.00	AO Smith	255	285	21.79	18.05	597,374.62	150	3.50	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-11363	15779.00	AO Smith	273	285	14.78	25.00	599,228.74	260	1.80	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-12357	15813.00	AO Smith	156	285	39.24	0.63	600,482.66	159	3.90	1.20	25-40	aw	i	nl	near GW	3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-14313	15879.00	AO Smith	318	285	19.89	2.30	603,009.13	341	1.90	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-16354	15948.00	AO Smith	297	285	19.60	20.29	605,553.82	70	2.60	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-16832	15966.00	AO Smith	250	285	5.74	34.18	606,205.55	54	2.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-17251	15978.00	AO Smith	318	266	6.56	33.27	606,679.07	313	5.10	1.20	<12.5	aw	e	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-19067	16034.00	AO Smith	12	295	8.96	30.91	608,868.62	218	4.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-22276	16141.00	AO Smith	351	285	20.81	19.00	612,987.22	349	2.50	1.20	25-40	iw	nd	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-24105	16205.00	AO Smith	24	285	18.30	5.21	615,167.21	2	3.00	0.90		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-31321	16209.00	AO Smith	297	285	17.65	22.27	615,286.04	294	1.60	1.80	12.5-25	iw	nd	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-24498	16218.00	AO Smith	321	285	15.01	24.80	615,631.17	317	3.80	1.80	12.5-25	aw	e	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-28677	16361.00	AO Smith	327	285	32.05	7.78	621,001.66	328	3.40	2.10	12.5-25	iw	nd	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
17-30599	16426.00	AO Smith	321	285	8.97	30.81	623,377.51	216	6.80	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
17-30866	16435.00	AO Smith	72	285	3.19	36.65	623,724.06	68	1.60	2.10	25-40	iw	nd	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
18-01965	16515.00	AO Smith	12	295	35.08	3.53	626,671.82	88	2.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-03078	16556.00	AO Smith	27	295	9.58	30.25	628,074.67	325	2.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-03440	16565.00	AO Smith	7	295	33.29	6.60	628,440.35	8	3.40	1.80		iw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
18-05773	16623.00	AO Smith	12	285	33.35	6.35	630,662.61	8	1.90	1.80		iw	e	nl	possibly weld defect	2	Not Selected	Short Feature - predicted failure pressure greater than SMYS.
18-06103	16633.00	AO Smith	327	295	24.24	15.63	631,045.79	318	2.50	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-07015	16662.00	AO Smith	25	295	36.66	3.21	632,179.53	25	1.90	1.20		iw	nd	nl	possibly weld defect	2	Dig Package	Adj. To Primary Feature
18-07009	16662.00	AO Smith	25	295	38.05	1.82	632,180.92	25	2.80	1.80	>40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
18-11168	16784.00	AO Smith	9	295	32.35	7.52	636,886.12	8	2.50	1.80		iw	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
18-12750	16835.00	AO Smith	10	295	0.65	39.26	638,810.38	146	2.70	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
18-13317	16854.00	AO Smith	6	295	7.02	14.67	639,529.31	7	2.10	1.20	25-40	iw	i	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
18-13722	16866.00	AO Smith	324	295	6.68	33.20	639,983.81	324	2.50	1.80		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-13729	16866.00	AO Smith	324	295	11.31	28.57	639,988.44	325	1.30	1.20	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
18-15033	16910.00	AO Smith	24	295	2.69	34.15	641,602.96	22	2.20	1.20	>40	iw	i	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
18-15043	16910.00	AO Smith	24	295	4.30	32.54	641,604.57	22	3.20	1.80	>40	iw	i	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
18-15590	16928.00	AO Smith	27	295	20.20	19.45	642,324.52	158	4.90	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-17151	16979.00	AO Smith	342	295	2.80	37.06	644,234.89	340	2.30	2.10	25-40	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
18-17203	16980.00	AO Smith	42	295	25.43	14.45	644,297.38	39	1.20	1.20		iw	e	nl	possibly weld defect	2	Not Selected	Short Feature - predicted failure pressure greater than SMYS.
18-17446	16990.00	AO Smith	351	295	5.13	34.74	644,635.80	25	3.20	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-17900	17005.00	AO Smith	30	295	8.22	31.65	645,234.82	162	4.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-19500	17058.00	AO Smith	318	295	28.17	11.71	647,322.91	317	2.20	2.40		iw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
18-20099	17077.00	AO Smith	25	285	35.07	4.81	648,084.38	160	5.30	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-23794	17186.00	AO Smith	344	285	19.32	20.75	652,042.89	171	13.70	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-29889	17397.00	AO Smith	348	285	28.12	11.71	659,789.64	348	12.60	2.10	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
18-30128	17407.00	AO Smith	345	285	18.88	20.96	660,129.48	342	2.50	1.80	25-40	iw	e	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
18-30292	17413.00	AO Smith	351	285	19.58	20.24	660,354.99	2	7.50	1.20		aw	e	nl	probably indication from attachment	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
18-30295	17413.00	AO Smith	351	285	22.62	17.20	660,358.03	2	4.20	0.90		bm	e	nl	possibly indication from attachment	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-30321	17414.00	AO Smith	285	305	2.47	37.34	660,377.70	5	3.10	1.80		bm	e	nl	possibly indication from attachment	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
18-31644	17461.00	AO Smith	21	285	19.79	20.06	662,227.83	166	2.00	1.20		bm	e	nl	curved	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
19-04350	17652.00	AO Smith	267	295	0.13	39.69	669,375.79	264	6.70	1.80		aw	e	nl	at GW	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
19-04570	17662.00	AO Smith	261	295	10.37	8.71	669,724.07	162	1.80	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
19-07450	17761.00	AO Smith	115	295	12.04	27.80	673,486.42	151	2.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
19-15023	18049.00	AO Smith	4	295	33.03	6.83	684,614.87	166	1.90	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
19-20518	18264.00	AO Smith	9	285	37.58	2.28	692,640.11	8	2.00	2.10	>40	iw	e	nl	possibly weld defect; strong	1	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
19-32049	18264.00	AO Smith	9	285	38.11	1.75	692,640.64	11	2.00	2.40	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
19-30452	18642.00	AO Smith	318	285	34.27	5.56	706,872.25	317	4.80	1.80	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
20-00904	18715.00	AO Smith	309	295	22.01	17.88	709,604.30	147	2.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-00917	18715.00	AO Smith	309	295	31.50	8.39	709,613.79	143	1.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-01087	18719.00	AO Smith	321	295	17.83	22.05	709,759.29	88	2.00	0.90		bm	i	nl		3	Dig Package	Adj. To Primary Feature
20-01086	18719.00	AO Smith	321	295	17.97	21.91	709,759.43	317	4.60	1.80	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
20-01164	18721.00	AO Smith	312	295	14.56	20.31	709,835.64	127	2.00	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-02065	18750.00	AO Smith	54	295	26.61	13.29	710,958.32	50	2.50	3.00	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
20-02792	18776.00	AO Smith	72	295	9.42	30.45	711,931.17	71	2.40	1.80	25-40	iw	e	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
20-03984	18820.00	AO Smith	326	295	3.87	35.97	713,109.30	4	1.90	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-04586	18836.00	AO Smith	312	295	19.52	20.27	713,743.19	153	2.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-05261	18857.00	AO Smith	20	295	32.42	7.43	714,547.01	19	11.00	2.40	12.5-25	iw	e	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
20-05796	18873.00	AO Smith	326	295	29.52	10.34	715,167.51	205	3.30	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-06375	18890.00	AO Smith	36	295	34.29	5.64	715,825.64	217	3.80	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-06893	18909.00	AO Smith	318	295	3.98	28.78	716,538.41	314	1.50	1.80	25-40	iw	e	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
20-06911	18909.00	AO Smith	318	295	25.34	7.42	716,559.77	314	3.30	1.80	25-40	iw	e	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
20-09175	18986.00	AO Smith	342	295	30.83	9.05	719,399.79	144	1.80	2.40		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-09287	18990.00	AO Smith	325	295	33.99	4.33	719,519.84	95	2.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-10835	19037.00	AO Smith	298	295	24.97	4.25	721,207.48	191	44.10	1.20		bm	i	nl	sloping; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-10897	19039.00	AO Smith	269	285	28.18	11.45	721,278.53	192	14.00	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-10944	19040.00	AO Smith	63	295	16.67	23.19	721,306.65	187	15.00	1.20		bm	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-26279	19040.00	AO Smith	63	295	19.62	20.24	721,309.60	187	34.20	1.20		bm	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-10950	19040.00	AO Smith	63	295	22.58	17.28	721,312.56	187	28.20	1.20		bm	i	nl	continuation of area 20-26279	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
20-10957	19040.00	AO Smith	63	295	26.41	13.45	721,316.39	187	35.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-13331	19117.00	AO Smith	19	295	8.17	31.71	724,230.71	18	2.90	2.10	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
20-14663	19163.00	AO Smith	107	295	0.48	14.57	725,769.76	169	37.40	1.20		bm	i	nl	intermittent; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-14666	19163.00	AO Smith	107	295	5.63	9.42	725,774.91	167	27.60	1.20		bm	i	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-14897	19180.00	Kaiser	321	285	9.92	30.12	726,013.06	179	6.80	1.20		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-15205	19186.00	Kaiser	321	285	35.41	4.72	726,272.20	93	3.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-16826	19235.00	Kaiser	351	285	39.08	0.96	728,231.66	66	10.90	1.80		bm	i	nl	at GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
20-16835	19236.00	Kaiser	21	285	14.25	25.80	728,246.87	68	8.20	2.10		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
21-03789	19655.00	Kaiser	60	295	35.16	4.90	744,764.73	150	2.80	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
21-07917	19778.00	Kaiser	312	295	1.84	27.24	749,564.35	352	1.70	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
21-08527	19793.00	Kaiser	9	295	31.88	8.18	750,168.78	270	1.30	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
21-17112	20083.00	Kaiser	276	295	0.88	39.00	761,013.77	89	36.80	1.20		bm	i	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
21-21586	20228.00	Kaiser	303	295	13.29	26.78	766,639.42	304	2.70	2.10		aw	e	nl	sloping	3	Not Selected	Short Feature - predicted failure pressure greater than SMYS.
22-04131	20500.00	Kaiser	69	295	11.22	28.77	777,009.59	40	4.10	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
22-20418	21015.00	Kaiser	330	295	19.96	20.04	796,892.36	153	1.90	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
22-23860	21103.00	Kaiser	300	266	8.21	31.24	800,393.20	200	1.40	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-03870	21238.00	Kaiser	9	285	2.82	36.67	805,649.57	148	2.30	2.40		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-06547	21336.00	AO Smith	306	285	26.22	3.38	808,985.35	59	1.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-06963	21349.00	AO Smith	282	285	13.43	26.41	809,474.86	170	32.40	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-07386	21363.00	AO Smith	330	295	33.79	6.19	810,027.79	126	5.30	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-09044	21418.00	AO Smith	78	285	2.83	37.04	812,083.54	76	9.00	3.00	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

	Excavated
	Not Excavated

IN-LINE INSPECTION																			EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
23-10872	21475.00	AO Smith	66	285	16.85	23.03	814,238.47	77	2.00	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-11326	21488.00	AO Smith	231	295	4.51	35.34	814,704.95	133	4.50	1.80		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-11560	21497.00	AO Smith	81	266	22.08	17.74	815,069.32	82	2.60	3.00	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
23-11659	21500.00	AO Smith	321	295	12.60	27.20	815,178.00	214	1.60	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-11704	21501.00	AO Smith	30	295	21.04	18.82	815,226.24	28	2.20	2.10	25-40	iw	nd	nl	possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
23-11713	21501.00	AO Smith	30	295	29.52	10.34	815,234.72	27	6.70	1.20	25-40	iw	nd	nl	Intermittent; possibly weld defect	2	Dig Package	Meets dig selection matrix criteria due to "possibly weld defect" comment
23-12084	21511.00	AO Smith	351	295	24.18	15.65	815,619.82	350	5.20	3.00	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
23-12783	21534.00	AO Smith	324	295	2.42	37.38	816,458.50	21	2.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-15196	21608.00	AO Smith	18	295	25.85	13.93	819,243.62	133	4.10	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-17906	21686.00	AO Smith	69	295	17.38	22.46	822,267.44	68	8.80	2.40	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
23-21391	21793.00	AO Smith	30	295	5.62	34.17	826,299.16	327	3.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-24022	21846.00	AO Smith	6	295	30.80	5.88	828,377.65	6	2.50	2.10	25-40	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
23-28314	21867.00	AO Smith	285	295	11.23	28.62	829,184.39	282	16.00	1.80	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
23-25801	21893.00	AO Smith	24	295	32.70	7.02	830,210.91	269	1.30	1.80		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
23-26199	21904.00	AO Smith	360	295	30.40	9.45	830,620.98	2	2.40	1.80	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
23-26237	21905.00	AO Smith	63	295	27.70	12.13	830,658.13	62	3.50	1.20	25-40	iw	i	nl	possibly weld defect	2	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
23-27378	21936.00	AO Smith	269	295	33.24	6.58	831,872.94	298	1.60	1.80	25-40	bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-00000	21956.00	AO Smith	327	295	18.98	20.91	832,655.88	325	1.30	1.80		iw	nd	nl	possibly weld defect	2	Not Selected	Short Feature - predicted failure pressure greater than SMYS.
24-04489	22046.00	AO Smith	306	295	6.98	32.88	836,077.38	90	7.80	2.10		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-05366	22064.00	AO Smith	315	295	0.90	38.93	836,753.85	316	6.40	1.50		aw	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
24-10189	22163.00	AO Smith	16	285	35.13	4.71	840,659.01	86	4.90	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-14167	22235.00	AO Smith	17	285	29.36	10.52	843,490.48	18	5.50	1.80	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
24-40669	22236.00	AO Smith	306	285	15.95	23.93	843,516.95	302	12.10	1.20	12.5-25	aw	e	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
24-14372	22239.00	AO Smith	16	285	22.52	17.35	843,643.16	17	1.50	1.80		iw	e	nl	possibly weld defect	3	Not Selected	Short Feature - predicted failure pressure greater than SMYS.
24-16248	22273.00	AO Smith	39	285	3.37	36.52	844,905.97	36	3.80	2.40	12.5-25	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																		EXCAVATION PROGRAM
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
24-18533	22320.00	AO Smith	306	285	0.70	39.19	846,709.11	165	36.10	1.80		bm	i	nl	sloping; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-20567	22362.00	AO Smith	18	285	8.03	31.83	848,316.79	14	7.30	2.10	25-40	aw	i	nl	possibly indication from Weld	2	Dig Package	Fails fitness for purpose remaining strength calculation
24-25027	22460.00	AO Smith	20	285	6.90	32.96	852,123.42	82	2.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-29278	22546.00	AO Smith	60	285	31.26	8.64	855,531.49	135	2.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-33501	22635.00	AO Smith	306	295	18.99	20.85	858,966.58	269	2.50	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-36205	22691.00	AO Smith	59	295	26.07	13.85	861,129.14	147	2.70	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
24-38359	22738.00	AO Smith	25	285	8.53	31.42	862,922.86	24	2.70	1.80		iw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
24-39731	22764.00	AO Smith	309	285	0.42	39.45	863,910.65	310	4.70	1.80	25-40	aw	i	nl	near GW	3	Dig Package	Fails fitness for purpose remaining strength calculation
24-39736	22764.00	AO Smith	309	285	1.95	37.92	863,912.18	310	4.90	1.80	12.5-25	aw	i	nl		3	Dig Package	Excavated for the purposes of gathering calibration information.
25-04308	22878.00	AO Smith	253	295	14.02	25.85	868,268.64	359	6.50	1.20		bm	i	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-04405	22881.00	AO Smith	150	295	6.26	33.88	868,369.12	149	5.40	2.40	12.5-25	aw	i	nl	sloping	3	Dig Package	Fails fitness for purpose remaining strength calculation
25-06959	22935.00	AO Smith	87	295	14.00	25.86	870,459.19	84	3.80	2.10	25-40	aw	i	nl		3	Not Selected	Fitness for Purpose - predicted failure pressure greater than SMYS.
25-07273	22940.00	AO Smith	33	295	24.91	14.88	870,669.35	145	2.10	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-07277	22940.00	AO Smith	33	295	28.73	11.06	870,673.17	151	3.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-10144	23001.00	AO Smith	26	295	23.63	16.25	873,029.83	7	3.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-12590	23059.00	AO Smith	324	295	25.70	12.20	875,274.36	163	2.00	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-21252	23257.00	AO Smith	263	285	21.72	18.16	882,633.94	148	3.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-28442	23420.00	AO Smith	57	285	33.60	6.25	888,852.69	92	2.10	2.10		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-37574	23475.00	AO Smith	264	295	11.72	28.08	890,885.00	170	13.60	1.20		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-31542	23491.00	AO Smith	254	285	1.84	38.07	891,454.15	258	6.70	1.20	25-40	aw	i	nl		3	Dig Package	Fails fitness for purpose remaining strength calculation
25-32062	23500.00	AO Smith	84	285	19.06	20.75	891,823.39	127	2.30	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-32888	23518.00	AO Smith	96	295	13.68	26.15	892,495.05	297	2.10	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
25-33159	23523.00	AO Smith	273	285	31.05	8.87	892,711.57	329	4.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-34060	23543.00	AO Smith	327	285	15.11	24.66	893,492.45	147	10.60	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
25-34120	23545.00	AO Smith	327	285	2.91	36.93	893,559.84	358	2.40	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
26-00286	23630.00	AO Smith	279	295	11.06	28.81	896,600.78	277	2.20	1.20		iw	nd	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - at-weld feature with no significant descriptors.
26-02456	23684.00	AO Smith	42	295	16.59	23.24	898,409.43	183	2.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
26-02502	23685.00	AO Smith	330	295	0.64	39.22	898,433.31	3	2.80	1.20		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
26-04710	23738.00	US Steel	321	295	17.79	13.66	900,244.44	83	2.40	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
26-12827	23952.00	US Steel	87	285	27.81	12.98	908,577.20	175	3.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
26-26814	24318.00	US Steel	69	285	40.05	0.64	922,799.08	92	1.90	0.90		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
27-07633	24507.00	US Steel	30	285	20.17	17.60	930,081.68	104	3.00	0.90		bm	e	nl	strong	2	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
27-11263	24588.00	US Steel	276	285	8.27	32.48	933,251.64	144	9.20	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
27-11671	24597.00	US Steel	27	285	19.55	21.16	933,627.94	14	8.50	0.90		aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
27-11979	24604.00	US Steel	294	285	0.96	33.00	933,883.11	324	3.00	0.90		bm	e	nl	near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
27-16718	24707.00	US Steel	21	295	8.32	31.69	937,971.18	22	3.10	1.20		aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
27-17744	24731.00	US Steel	321	285	32.19	8.43	938,747.91	316	13.10	2.40	12.5-25	aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
27-21824	24820.00	US Steel	282	285	31.76	8.89	942,212.49	146	10.10	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
27-28321	24963.00	US Steel	48	285	35.47	5.26	947,760.75	183	6.10	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-05342	25106.00	US Steel	27	285	12.02	27.18	953,384.09	230	6.10	0.90		bm	e	nl	sloping	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-08071	25163.00	US Steel	96	285	26.82	12.43	955,633.69	129	3.10	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-31055	25175.00	US Steel	15	285	11.78	28.97	956,095.81	2	18.00	1.20		bm	e	nl	intermittent	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-09715	25199.00	US Steel	99	285	16.71	23.04	957,058.69	99	3.10	3.00		aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
28-10410	25213.00	US Steel	96	295	24.63	16.13	957,633.84	157	10.80	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-10422	25213.00	US Steel	96	295	26.85	13.91	957,636.06	326	16.30	2.10		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

TABLE 3.1 - Line 3 (34") Crack Program - Notch-Like Features
Disposition Summary

Excavated
Not Excavated

IN-LINE INSPECTION																	EXCAVATION PROGRAM		
Area No.	Pipe No.	MFG	LW. [°]	Wt. [mil]	DuGW [ft]	DdGW [ft]	Distance [ft]	Deg [°]	Length [inches]	Width [inches]	Est. Depth [%WT]	Rel. Pos.	Rad. Pos.	Type	Comment	Priority	Disposition	Comment
28-10438	25213.00	US Steel	96	295	33.97	6.79	957,643.18	326	6.70	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-31307	25229.00	US Steel	291	285	31.73	7.60	958,269.24	8	3.10	1.50		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-12248	25246.00	US Steel	39	295	5.86	34.92	958,926.65	33	2.40	1.80		aw	e	nl	sloping	3	Dig Package	Additional dig due to US Steel - At Weld
28-13939	25279.00	US Steel	6	295	21.75	19.04	960,246.88	1	2.60	1.20		iw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
28-19131	25383.00	US Steel	306	285	26.68	13.34	964,328.15	302	5.60	0.90	25-40	aw	i	nl		3	Dig Package	Additional dig due to US Steel - At Weld
28-19716	25395.00	US Steel	273	295	12.13	27.64	964,788.19	274	1.40	2.10		aw	e	nl		3	Dig Package	Additional dig due to US Steel - At Weld
28-22167	25446.00	US Steel	21	285	0.90	38.08	966,804.20	149	9.50	1.20		bm	e	nl	sloping; near GW	3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-22376	25450.00	US Steel	3	285	9.52	27.10	966,973.24	22	4.10	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-24459	25492.00	US Steel	333	285	7.62	32.60	968,661.81	203	2.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-27966	25569.00	US Steel	21	295	29.08	11.66	971,704.93	26	2.90	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-28725	25583.00	US Steel	12	295	6.37	34.41	972,240.51	91	4.20	1.20		bm	e	nl		3	Dig Package	Adj. To Primary Feature
28-28801	25584.00	US Steel	300	295	11.58	29.13	972,286.50	241	2.10	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
28-30970	25630.00	US Steel	3	285	15.02	25.75	974,117.91	126	5.30	0.90		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
29-22916	26141.00	US Steel	93	295	14.14	26.73	994,033.63	57	5.90	3.60		bm	e	nl	& corrosion	2	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
29-22992	26143.00	US Steel	66	295	5.37	35.05	994,099.89	79	2.50	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
29-25017	26185.00	US Steel	324	266	8.31	32.76	995,674.75	242	5.60	1.80		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
29-25006	26185.00	US Steel	324	266	9.14	31.93	995,675.58	243	8.30	1.20		bm	e	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.
29-25352	26191.00	US Steel	51	295	24.38	16.67	995,929.86	167	14.90	1.20		bm	i	nl		3	Not Selected	Does Not Meet Dig Selection Criteria - base metal "nl" indications are minor features.

OPS Question #2 – Bullet 6

Please provide clarification for the following "notch-like" features found in Table 3.1

- *Please clarify why some notch-like features with the comment "possible weld defect" are not selected for excavation. It appears that they meet the dig selection matrix. Would they have been selected if there was no depth information to perform a fitness for purpose calculation?*

Response:

Some notch-like features with the comment "possible weld defect" were selected for excavation as per the dig selection matrix prior to Enbridge obtaining depth estimations from the ILI vendor. Once these depth estimations were available, there was sufficient defect data to perform individual fitness for purpose evaluations for each defect, including some "nl – possible weld defect" features. These defects would have been selected for excavation if insufficient data existed to conduct the fitness-for-purpose analysis.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #3

The fitness for purpose calculation (engineering assessment) for notch-like features appears to use a Charpy toughness of 15. Is this equally applicable for A.O. Smith, Kaiser and USS pipe? In the explanation please include the relevance of Kiefner's report on the MP 954 cut-out (A.O. Smith pipe) where the Charpy was no lower than 4, but could be as high as 9. These values are lower than 15.

Response:

A Charpy toughness value of 15 was selected for the fitness-for-purpose calculations because it is a relatively low value of toughness compared to the pipe used in Line 3. US Steel pipe has measured toughness values ranging from 30 to 37 ft-lbs, A.O. Smith pipe has measured toughness values in the order of 25* ft-lbs, and Kaiser pipe data is not available. The Kaiser pipe is assumed to have similar toughness properties as the US Steel pipe considering it is of the same vintage and manufacturing process. As a result, using a Charpy toughness value of 15 ft-lbs is applicable for all pipe types and will provide increasingly conservative results for pipes with increasing actual toughness. This approach is intended to provide a realistic yet conservative estimate of the predicted failure pressure for crack-like flaws and a correspondingly conservative method for selecting features for excavation and repair.

The Kiefner and Associates Inc. report on the MP 954 cutout describes that the toughness of this type of steel was measured to be at least 4 ft-lbs from a previous analysis and it also states that the actual toughness is not known and "may have in fact been much greater." This provided the start point for the MP 954 analysis, which stated that a 4 ft-lb toughness predicts failure at 643 psi. We know that this defect passed pressure tests to higher levels so the toughness has to be greater than 4 ft-lbs. KAI goes on to say that an effective toughness of 9.0 ft-lbs would be required to produce a predicted failure pressure of 868 psi. This is only significant because it represents a pressure of 100% SMYS. The actual failure pressure of the defect is unknown, therefore, the toughness of the pipe must be greater than 9.0 ft-lbs. In other words, this analysis does not define the actual toughness, it simply describes a minimum amount of toughness that must exist within that pipe.

* This was a result from the Enbridge 26 inch diameter pipeline which is also API 5LX – X52 pipe and is representative of the toughness of the 34 inch diameter pipe.

U.S. DOT, Office of Pipeline Safety, Questions for Clarification on Enbridge's Submission of October 16, 2003 - CPF 3-2002-5017H

OPS Question #4

In Tab 5 the summary states that 2008 is justified for a CD inspection from Gretna to Clearbrook based on a remaining life analysis of 2mm x 150mm defect left in the line. Keifner's analysis (6/19/03) was included as backup. Reviewing Kiefner's analysis it appears that he used 1mm x 150mm as shown on p. 15 and Fig. 5 of his report. Please clarify. Also, why wasn't 190mm long (approx. 7.5") used, as was done on Clearbrook to Superior analysis? It appears for USS steel pipe that a Charpy toughness of 40 is used in the calculations. Is this Charpy value valid for A.O. Smith pipe, which tends to have lower toughness values for the flash weld?

Response:

Page 15 and Figure 5 of the Kiefner and Associates Inc. report (06/19/03) does use a flaw size of 1 mm deep by 150 mm long. This defect was used to develop a model that could also be used to assess similar length defects at varying depths as shown along the y-axis of Figure 5 in the report. In order to develop an inspection plan, a starting defect deeper and longer than the Ultrascan CD tool detection limits (1mm deep x 60 mm long) was considered. The size of defect considered was 1.5 mm deep (incorrectly described as 2 mm in the response to Question 5 of the September 5, 2003 OPS information request) and 150 mm long. Utilizing the average annual pressure spectrum, upper bound crack growth parameters and starting flaw size greater than the tool capability yielded a predicted life in excess of 25 years as described in Question 5 of the September 5, 2003 OPS information request.

The reason that a length of 150 mm was used as opposed to 190 mm is because the Gretna to Clearbrook analysis was completed prior to the laboratory determination of the length of the Cohasset defect. As a result, we utilized the typical size of fatigue crack previously experienced in the Enbridge system which is approximately 6 inches (152mm). The Clearbrook to Superior fatigue analysis utilized the 7.5 inch length of the Cohasset defect. Both of these defects provide a reasonable crack behavior model and both are several factors larger than the Ultrascan CD tool detection limits.

Fatigue crack growth rates are independent of pipe toughness. Therefore, the basis for using a toughness value of 40 ft-lbs in this analysis is to ensure that a large initiating flaw is incorporated in the model. A large initiating flaw in a fatigue life estimate will ensure that a shorter expected life is predicted, hence a more conservative result. This approach was also used for A.O. Smith pipe to ensure that the analysis utilized initiating defects larger than what would exist in a low toughness pipe, adding additional conservatism.

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November 18, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby / JB

Mark Willoughby

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 sec	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 sec	Pressure backed up when a Floodwood unit was stopped due to a power consumption.
05/19/03	PL	466 psig	5.42%	53 sec	Sediment plugged the Clearbrook transmitter line causing a faulty reading.
09/04/03	GF	448 psi	2.50%	20 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection.
09/04/03	VK	349 psi	5.70%	53 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection. Pressures fluctuated +/- 5psi of MAOP for approximately 20 minutes after the shutdown
09/11/03	VK	349 psi	5.70%	20 sec	Slow acting PCV at Viking Station
09/14/03	MP 1002	435 psi	3.50%	30 sec	Faulty pressure transmitter. We do not believe pressures actually exceeded allowable.
10/03/03	VK	352 psi	6.70%	40 sec	Line shutdown Cromer to Clearbrook for a CR fullstream injection. Settling of line pressures after the shutdown.
10/11/03	GF	455 psi	4.10%	20 sec	Line startup from Cromer to Superior. Pressure exceeded for 1 scan as units were being brought on.
10/12/03	VK	342 psi	3.60%	10 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 10 secs at Viking during the swing.
10/13/03	VK	345 psi	4.50%	40 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 40 secs at Viking during the swing.
10/16/03	VK	339 psi	2.70%	45 sec	Pressure spike at Viking during a non-routine change in line rate. Pressure peaked at 339 psi.
10/20/03	VK	360 psi	9.00%	20 sec	Line startup from Cromer to Superior. Pressure spike as units were brought on line.
10/22/03	VK	350 psi	6.00%	40 sec	During a L3 startup following a L3 Clearbrook injection the discharge pressure at Viking spiked for approx 40 sec when unit 2 failed to start.
10/26/03	VK	341 psi	3.30%	20 sec	L3 startup Cromer to Superior. Pressure over shot discharge setpoint momentarily while bringing units on.
10/26/03	GF	445 psi	1.80%	15 sec	L3 startup Cromer to Superior. Operator dropped a Gretna unit in reaction to pressures at Viking exceeding setpoint causing momentary pressure spike at Gretna

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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November 6, 2003

NEXT DAY MAIL

Mr. Ivan Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2002-5017H

Dear Mr. Huntoon:

Further to our October 16 letter and my recent conversation with Dave Barrett, I would like to reaffirm Enbridge's position that all required work has been completed for the above-referenced subject, and we look forward to final OPS approval of pressure restoration for the 34-inch pipeline. In addition, we remain on schedule for providing you the three additional miscellaneous items by the end of the year, as requested in your September 5 letter.

In our October 16 letter, we confirmed that all required repairs have been completed. Given the detailed analysis and overall scrutiny of our 34-inch line, we felt it appropriate to inform you of a minor dent at MP 1072. This is located approximately 29 miles downstream of Floodwood, is subject to relatively low mainline pressures, and is scheduled for field investigation by the end of 2003. We are treating this dent in accordance with our standard methods, as detailed in our Operating & Maintenance Procedures manuals. This anomalous dent feature is not related to cracking or stress corrosion cracking. Enbridge has been aware of this anomaly, and appropriately scheduled field investigation for winter when the marshy area will be frozen, in order to better facilitate the work. We do not view this repair as part of the 34" dig program; therefore, it should not be considered as one of the requirements for removing the 34" pressure restrictions.

While the above issue is noteworthy since it involves the 34-inch line, we are notifying you in order to avoid any confusion with or connection to the process in place, ultimately geared toward pressure restoration on our 34-inch line. We appreciate OPS efforts to date toward understanding the Enbridge pipeline system and its related programs. Enbridge strives to maintain open communication with the OPS and will continue to proactively address items of potential concern.

Should you have any questions or would like to discuss any of the above information in further detail, please contact me.

Sincerely,

John R Sobojinski
fb

John R. Sobojinski

c: Dave Barrett
John Hayes
Walter Kresic
Art Meyer
Mark Sitek
Mark Willoughby

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November 3, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby / JF

Mark Willoughby

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 sec	Slow acting PCV at PR
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09/04/03	GF	448 psi	2.50%	20 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection.
09/04/03	VK	349 psi	5.70%	53 sec	Line shutdown Cromer to Clearbrook for a CR full stream injection. Pressures fluctuated +/- 5psi of MAOP for approximately 20 minutes after the shutdown
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10/11/03	GF	455 psi	4.10%	20 sec	Line startup from Cromer to Superior. Pressure exceeded for 1 scan as units were being brought on.
10/12/03	VK	342 psi	3.60%	10 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 10 secs at Viking during the swing.
10/13/03	VK	345 psi	4.50%	40 sec	Line 3 injection/delivery swing at Clearbrook. Pressure spiked for 40 secs at Viking during the swing.
10/16/03	VK	339 psi	2.70%	45 sec	Pressure spike at Viking during a non-routine change in line rate. Pressure peaked at 339 psi.
10/20/03	VK	360 psi	9.00%	20 sec	Line startup from Cromer to Superior. Pressure spike as units were brought on line.
10/22/03	VK	350 psi	6.00%	40 sec	During a L3 startup following a L3 Clearbrook injection the discharge pressure at Viking spiked for approx 40 sec when unit 2 failed to start.
10/26/03	VK	341 psi	3.30%	20 sec	L3 startup Cromer to Superior. Pressure over shot discharge setpoint momentarily while bringing units on.
10/26/03	GF	445 psi	1.80%	15 sec	L3 startup Cromer to Superior. Operator dropped a Gretna unit in reaction to pressures at Viking exceeding setpoint causing momentary pressure spike at Gretna

Legend:			
GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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October 21, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were two pressure excursions over allowables this past week, the attached chart reflects those changes.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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09/14/03	MP 1002	435 psi	3.50%	30 seconds	~~Faulty pressure transmitter. We do not~~ believe pressures actually exceeded allowable.
10/03/03	VK	352 psi	6.70%	40 seconds	Line shutdown Cromer to Clearbrook for a CR fullstream injection. Settling of line pressures after the shutdown.
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10/16/03	VK	339 psi	2.70%	45 seconds	Pressure spike at Viking during a non-routine change in line rate. Pressure peaked at 339 psi.
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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October 16, 2003

NEXT DAY MAIL

Mr. Ivan Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2002-5017H

Dear Mr. Huntoon:

Enbridge Energy, Limited Partnership (Enbridge) has reviewed your letter dated September 5, 2003 regarding Enbridge's proposed Return-to-Service Plan. The original plan was filed with the Office of Pipeline Safety (OPS) on July 8, 2002 following the July 4, 2002 leak on Enbridge's Lakehead System Line 3 near Cohasset, Minnesota.

Your letter outlined three required modifications to the Return-to-Service plan and requests for five additional information items. We understand that upon completion of all repairs, modification of the Plan as required and submission of the requested information, OPS will consider restoration of pressure as follows: Pressure would be restored to 100% of the Base Maximum Discharge Pressure (BMDP) between Gretna and Clearbrook with the exclusion of Viking Station; Enbridge is to propose a specific BMDP for Viking Station; pressure would be restored to 90% of BMDP between Clearbrook and Superior with the exception of Cass Lake; and Cass Lake will be remain at the current BMDP of 603 psi.

The attached information packet provides the three required modifications to the Return-to-Service plan and includes detailed responses to the five additional information items. We would also advise that the required repairs have been completed. Enbridge therefore requests that OPS confirm that pressures can be restored to the levels described in its letter dated September 5, 2003 as soon as possible.

In response to your request for a specific BMDP for Viking Station, Enbridge proposes to establish the BMDP for Viking Station at 687, which is well below its design and test pressure of 1480 psig.

OPS had also requested that three additional miscellaneous requirements be provided by December 31, 2003. While these were not conditions precedent for the restoration of pressure as described above, we want to confirm our intention to fulfill these requirements within the time frame requested.

Enbridge further understands from the OPS letter dated June 26, 2003 and your most recent correspondence that "after completion of the CD Tool Survey and associated repairs in 2005, OPS expects to grant Enbridge complete pressure restoration" between Clearbrook, Minnesota and Superior, Wisconsin. OPS has stated that the rationale for this "tiered" approach to lifting pressure restrictions is supported by its belief that internal crack growth rates need to be established with greater confidence, using the 2005 CD internal inspection tool run.

We agree that the 2005 CD reinspection will provide additional insight regarding crack growth rate but do not concur that a continued pressure restriction is required between Clearbrook to Superior until that time. Enbridge discussed with OPS the potential for an early internal inspection in 2005 in order to permit restoration to full pressure. Enbridge has demonstrated that while some defects in the longitudinal weld or pipe body are expected to grow, as they would in any pipeline, growth modeling demonstrates that reinspection in 2005 is years in advance of significant crack growth concerns. The crack growth rate analysis used is based on industry accepted techniques that are applied routinely for pressure vessels utilized by many industries. As the 2005 CD tool run commitment already builds in an extensive degree of conservatism, a further pressure restriction appears arbitrary and not supported by the evidence reviewed to date.

Nevertheless, Enbridge understands that a ten percent pressure restriction on BMDP will remain in effect between Clearbrook and Superior until completion of the 2005 tool run and associated repairs per your direction. Enbridge expects to continue its work in the area of crack growth modeling, pressure spectrum analysis and remaining life calculation. If supplementary relevant information is gained beyond that already presented, Enbridge will request an audience to review its findings with the OPS and, if our crack growth model is further validated, seek a lifting of the pressure restriction prior to the 2005 CD reinspection.

Enbridge looks forward to the approval of pressure restoration for the 34-inch pipeline in the manner described. We have completed all required work and therefore request your final approval as soon as possible. Should you require further information or have any questions or concerns, please contact me.

Sincerely,

John R. Sobojinski

Attachment
c: Denise Hamsher
John Hayes
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Mark Willoughby
c/att: Joy Kadnar
H. Noel Duckworth
Brian Pierzina

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October 14, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were three pressure excursions over allowables this past week, the attached chart reflects those changes.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /jjf

Mark Willoughby

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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October 6, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

~~CPT No. 3-2002-5017H~~

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There was one pressure excursions over allowables this past week, the attached chart reflects that change.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /DD

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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DN	Donaldson	MP 1002	Midline transmitter at the rupture site
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September 29, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week, therefore the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /JJ

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior
		VK	Viking

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Excerpt from Enbridge Return-to-Service Plan
(Revised September 30, 2003)
1.0 Executive Summary

This document was prepared for the OPS to serve as the return-to-service plan upon which subsequent investigation and mitigation programs would be conducted to verify the integrity of the 34-inch line segment. Key aspects of the plan include:

1. Implementation of a precautionary temporary pressure restriction until the exact cause of the failure has been determined and prudent remediative measures have been implemented to ensure the pipeline can operate safely at normal operating pressure.

2. A metallurgical assessment to determine the exact cause of the failure.

3. Completion of crack inspection from Clearbrook, MN to Superior, WI using the best available in-line crack detection technology.

4. Completion of a field investigation and repair program to evaluate and mitigate any crack or crack-like features identified as a result of the in-line inspection program (and/or other potentially injurious indications that are discovered as a result of the inspection).

5. Continuation of analysis and excavation programs on the 34-inch line upstream of Clearbrook based on a 2001 crack tool inspection of the Gretna to Clearbrook section of line.

6. Analysis of other local factors that may be unique to this location and that may have contributed to the failure at MP 1002.73.

7. Reanalysis of pressure cycling studies on the 34-inch line using current historical pressure cycling information.

8. Analysis of alternatives to reduce pressure cycling downstream of Clearbrook to determine if additional operational efficiencies may be possible.

9. Supplemental research on crack growth studies to better define inspection intervals for in-line crack inspections.

10. Re-inspect the Clearbrook to Superior section of pipeline in 2005 using the best available in-line crack detection technology.

11. Submit Quarterly reports to the Director, Central Region, OPS verifying the validity of the assumptions used in the remaining life calculations (starting in the first Quarter following restoration or partial lifting of pressure restrictions as noted in item 1 above).

In addition to the above, Enbridge intends to re-inspect the Gretna to Clearbrook section of the 34 inch Line 3 / Line 4, using the best available in-line crack detection technology, in 2008. The re-inspection interval is based on analysis of operating and pipeline integrity conditions upstream of Clearbrook. This interval may be adjusted based on the results of ongoing pipeline integrity analysis.

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September 16, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There was one pressure excursion over allowables this past week. The attached chart provides the details of that occurrence. In addition, the excursion on September 14, 2003, was actually a faulty pressure transmitter due to a loose wire in the control box; therefore, we do not believe the pressure actually exceeded allowables.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /JB

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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September 22, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week, therefore the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /
Mark Willoughby

Attachment

c: David Bryson
John Hayes

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		VK	Viking

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September 9, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were two pressure excursions over allowables this past week; therefore, the attached chart provides the details of those occurrences.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby /JH

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

VIA FACSIMILE & CERTIFIED MAIL

September 5, 2003

Mr. John Sobojinski
Enbridge Pipelines, LLC
119 North 25th Street East
Superior, WI 54880-5247

RE: CPF No. 3-2002-5017H
August 14, 2003 Meeting

Dear Mr. Sobojinski:

Thank you for meeting with representatives of the Office of Pipeline Safety (OPS) in Kansas City on August 14, 2003. The purpose of the meeting was for Enbridge to present their response to OPS's evaluation of the Return-to-Service Plan (Plan) for the 34-inch pipeline. Based on the items discussed at the meeting, please make the following modifications to the Plan, and provide the additional information requested below.

Required Modifications to Return to Service Plan

Consistent with OPS's June 26, 2003 letter, prior to approving the Plan or granting any increases in pressure, the following modifications to the Return-to-Service Plan are required.

1. Add the requirement to run GE's PII Ultrascan CD tool in the 34-inch pipeline from Clearbrook to Superior in 2005.

2. Add the requirement to submit to the Director, Central Region, OPS quarterly reports verifying the validity of the assumptions made in the remaining life calculations. These reports should be based on the pressure cycle counting results of monitoring the pressure spectrum at all pump station discharge points on the 34-inch pipeline.

3. Include a requirement stating when the 34-inch pipeline from the US-Canadian border to Clearbrook will be internally inspected using the CD tool. The timing of the next CD tool run should be based on the integration of all available data, including the results of the 2001 CD tool run, associated excavations and repairs, remaining life calculations, etc.

Required Additional Information

Prior to granting any increases in pressure the following information is required.

1. Provide an updated excavation results spreadsheet, which was previously submitted in April 2003, including the tool vendor results and NDE findings upon excavation. Please provide in both electronic and printed formats.

2. Provide a repair program summary, including; number and type of features, features excavated, features requiring sleeve repair, and features requiring grinding and re-coating. Please provide in spreadsheet and bar graph formats.

3. Resubmit Table 3.1 in response to Question #3 of OPS's June 26, 2003 information request. Table 3.1 delineated the disposition of all notch-like features. Update Table 3.1 to provide a brief explanation of the reason for each notch-like feature's disposition. Also provide a detailed description of the actual Engineering Assessment (EA) used as the criterion to determine the disposition of certain notch-like features.

4. Provide an analysis of the 4" long, 75% deep indication found in the vicinity of MP 954 to determine a defect growth rate for this particular feature. Explain the relevance of this feature's defect growth rate considering the previous hydrostatic test and the Elastic Wave tool run. The analysis should also make a comparison to the growth rate used for the current remaining life calculations.

5. Submit documentation justifying the inspection interval for the future CD tool run from the US-Canadian border to Clearbrook.

Restoration of Normal Operating Pressure

At this time OPS cannot grant Enbridge's August 6, 2003 request for full restoration of normal operating pressure. Upon completion of all repairs, and based on an acceptable response by Enbridge to modify the Plan and submit updated information, OPS will consider a restoration of pressure on the 34-inch pipeline as follows:

Gretna to Clearbrook:	Restore discharge pressures at all pump stations to 100% of the Base Maximum Discharge Pressure (BMDP) in existence before the July 4, 2002 failure near Cohasset, MN. Viking Station was not operational on the 34-inch pipeline immediately prior to the July 4, 2002 failure; therefore, Enbridge should propose a specific BMDP for OPS's consideration.
Clearbrook to Superior:	Discharge pressures at all pump stations (excluding Cass Lake Station) at no more than 90% of the Base Maximum Discharge Pressure (BMDP) in existence before the July 4, 2002 failure near Cohasset, MN. OPS will consider allowing Cass Lake to remain at the current BMDP of 603 psig.

Consistent with public safety, OPS believes that maintaining a pressure restriction on the Clearbrook to Superior section is necessary until completion of the CD tool run in 2005, and acceptable progress is demonstrated on the 34-inch pipeline Risk Management Plan. In your August 6, 2003 letter, Enbridge asserted that maintaining a pressure restriction following internal inspection and remediation using a crack detection tool communicates to industry that OPS does not accept high technology internal inspection devices. OPS rejects this assertion, precisely because of the recent CD tool findings between Clearbrook and Superior. According to Enbridge approximately 95% of all crack-like defects and crack-fields on the 34-inch pipeline in the U.S. were between Clearbrook and Superior. It has been established that fatigue cracks and SCC grow in service, and that both major releases caused by cracking in 1991 and 2002 occurred between Clearbrook and Superior. Therefore, a pressure restriction is necessary as an added precaution, until crack growth rates can be established with greater confidence using the 2005 CD tool run.

Miscellaneous Requirements

Please provide the following by December 31, 2003.

1. A final report of the Trail, MN leak on April 23, 2003. The report should include the results and conclusions from the investigation for high carbon equivalent pipe in the 34-inch pipeline.

2. Provide a copy of Rick Sandahl's letter to Operations discontinuing the stress corrosion cracking investigation program on the Lakehead system in the mid-1990's.

3. Please submit an initial draft of a Risk Management Plan for the 34-inch pipeline. The Risk Management Plan should include a project time-line for implementation of the risk analysis, review of risk analysis results, consideration of all possible mitigative measures, and the criteria for implementation of chosen mitigative measures. Enbridge shall periodically consult OPS for concurrence at key decision points.

If you have any questions regarding the information requested please contact me or my staff.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

cc: Mr. Dan Tutcher
Enbridge Energy Company, Inc.

Mr. Charles Kenow
Minnesota Office of Pipeline Safety

Joy Kadnar
Office of Pipeline Safety

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ENBRIDGE™

September 3, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

Mark Willoughby / jf

Mark Willoughby

Attachment

c: David Bryson
John Hayes

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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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ENBRIDGE™

August 24, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

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Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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August 12, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

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If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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ENBRIDGE™

August 19, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

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If you have any questions regarding the information provided, or on any other matters, please contact me at (715) 394-1505.

Sincerely,

J R Sobojinski / JB
John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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August 6, 2003

James K. O'Steen
Deputy Associate Administrator
of Pipeline Safety
U.S. Department of Transportation
400 Seventh Street SW
Washington, DC 20590

Dear Mr. O'Steen:

Re: Enbridge Return-to-Service Plan CPF No. 3-2002-5017H

Enbridge Energy, Limited Partnership (Enbridge) has reviewed the Office of Pipeline Safety (OPS) letter dated June 26, 2003 in response to the proposed Return-to-Service Plan. The proposed Return-to-Service Plan was filed by Enbridge with OPS on July 8, 2002 following a July 4, 2002 leak on the Lakehead System's Line 3 near Cohasset, Minnesota.

Over the past year Enbridge has:

- implemented a precautionary temporary pressure restriction on the portion of the Lakehead System covered in the Return-to-Service Plan;
- worked with the NTSB and OPS to determine the exact cause of the failure;
- completed a high resolution ultrasonic inspection analysis of the 34-inch pipeline between Gretna, Manitoba and Superior, Wisconsin using the best available in-line crack detection technology;
- completed a field investigation and repair program of this segment to evaluate and mitigate any crack or crack-like features;
- analyzed local factors that may be unique to this line segment; and
- analyzed pressure cycling effects based on the highest level of cycling that has been observed in recent years.

In addition, Enbridge and OPS have discussed the option of conducting a second internal inspection for cracks between Clearbrook to Superior in 2005, if the OPS viewed an early inspection to be of benefit. Enbridge has also responded to substantive information requests, has shared extensive information without reservation, has invited OPS inspectors to observe the remediation program and has arranged for Enbridge representatives as well as those of the internal inspection vendor, General Electric, to attend a series of meetings with OPS staff.

Based on the June 26, 2003 OPS Response, Enbridge would understand the following: First, Enbridge understands that the elements described in the Return-to-Service Plan were, for the most part, acceptable with the addition of certain items. Second, that reinspection of the section between Clearbrook and Superior in 2005 is preferred by OPS and should be added to the Return-to-Service Plan. Third, that the fourteen items outlined in the June 26, 2003 OPS Response require additional information. Finally, Enbridge understands that OPS may be considering a delay in the restoration of normal operating pressure limits until an independent analysis of our risk analysis program and pipe life calculations have been completed, and until after the 2005 reinspection.

In replying, it is worth noting that Enbridge and the Office of Pipeline Safety have worked together over the past year to share extensive information and to address the issues noted above. The fact that there is agreement on many of the issues reflects this effort and Enbridge would extend its appreciation to the many parties involved. As noted verbally, Enbridge will:

- continue in its commitment to the Return-to-Service Plan filed on July 8, 2002;
- complete all remaining digs and mitigation actions based on the internal inspection results; and
- reinspect the pipeline section between Clearbrook and Superior in 2005 thereby accelerating the reinspection interval by several years.

Enbridge believes that the attached technical data and responses to the 14 items described in the June 26, 2003 OPS letter further confirm that inspection results, remediation program and action plans are valid. It is understood that OPS may utilize independent analysis in review of the last item; however, Enbridge would urge OPS to consider having its own technical staff complete any further review, without the need for independent analysis, given their familiarity with similar information on the Lakehead System as a result of both recent information requests and the comprehensive audit. Enbridge requests that OPS minimize the potential for further delays in its review process given that approximately one year has passed since the proposed Return-to-Service Plan was filed.

Enbridge strongly believes that sufficient data has been presented and validated to support a return to normal operating pressures as described above and in the Return-to-Service Plan. Enbridge shares OPS expectations that these actions should be expected to adequately reduce the risk of failure due to cracking. Enbridge believes that there is strong evidence that the risk of failure has been adequately reduced without a continued pressure reduction through the time of the next internal inspection. It is expected that the imposition of continued pressure restrictions, immediately following a full internal inspection for cracking and remediation program, will effectively communicate to industry that the Office of Pipeline Safety has not accepted high technology internal inspection technologies for cracking. This position is expected to negatively impact the application and development of a now-proven technology, as well as future technologies, that would otherwise serve to enhance public safety while reducing the potential for pipeline leaks. The following provides the basis for this concern:

First, Enbridge and General Electric representatives have demonstrated the capabilities of high resolution internal inspection technology for cracking through laboratory analysis, through applications within the Enbridge pipeline network and through reports on other pipeline system inspections that now, in total, exceed over 10,000 kilometers. Representatives of Enbridge and General Electric have traveled from various locations in the United States, Canada, the United Kingdom and Germany to explain the operation of the tool, its technology and associated capabilities. OPS questions have been addressed through a number of information requests and in a series of meetings in Kansas City. OPS has also been provided with examples of the acceptance of this technology in other countries by federal regulatory agencies. Enbridge believes that the technical basis for acceptance of this technology has been provided and that such has been proven to reduce the potential for pipeline releases and enhance public safety.

Second, Enbridge understands that the Inspector General has strongly encouraged the implementation of this very type of technology. On May 11, 2000 the Inspector General's Office testified before the Senate Committee on Commerce, Science and Transportation of the need for internal inspection technologies that can detect defects in seam welds, pipeline materials and detect stress corrosion cracking. The testimony went on to note that "Pipeline Operators and Federal and State Inspectors need advanced technologies to locate problems and monitor pipelines *before* a failure occurs. High technology inspection devices could give operators and inspectors early warnings of serious problems in a pipeline and lower the risk of pipeline releases." General Electric has developed this technology and Enbridge has applied it to meet the very needs described in the Inspector General's report to Senate.

Third, Enbridge has had Kiefner and Associates, one of the most respected experts in this area of study, produce a number of scenarios forecasting the growth characteristics of features in the pipeline based on the highest level of cycling that has been observed in recent years. In response to an OPS request, Enbridge also requested an analysis of an extremely hypothetical case in which it was assumed that the current inspection did not detect a defect that exceeded General Electric detection thresholds. In fact, the hypothetical case assumed that the tool had not reported a defect that was approximately 2 times the depth and 3 times the length of the tool detection thresholds. To be clear, there has been no known or reported occurrence in which the Ultrascan CD Crack Detection Tool has not reported a defect with the dimensions of the "hypothetical" defect. Nevertheless, this analysis concluded that this hypothetical defect would have approximately 6.4 years of life before it would grow through to failure. On this basis, there is no reason to delay restoration of normal operating pressures until a second inspection is completed two years hence.

Enbridge therefore seeks approval from the Office of Pipeline Safety to permit normal operating pressures on this line segment to resume with the acknowledgment that internal inspection, the integrity assessments, mitigation measures and future conservative integrity assessment plan have adequately reduced the risk of a fatigue-crack failure on this segment.

Sincerely,

John R. Sobojinski

c: Daniel Tutcher, Group Vice President
Art Meyer, Vice President Technology
Walter Kresic, Manager Pipeline Integrity

c/att: Ivan Huntoon
Joy Kadnar
Brian Pierzina
H. Noel Duckworth

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August 5, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski ljf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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July 29, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

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Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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CPF-3-2002-5017

SF-00006-05(4/86)

STATE OF MINNESOTA

Office Memorandum

DEPARTMENT : POLLUTION CONTROL AGENCY

DATE : June 19, 2003

TO : Gerald Resendahl, Minnesota office of Pipeline Safety, Department of Public Safety
Charles Kenow, Minnesota office of Pipeline Safety, Department of Public Safety
Ivan Huntoon, United States Department of Transportation, Office of Pipeline Safety

FROM : Stephen J. Lee, Supervisor SJL
Emergency Response Team
Minnesota Pollution Control Agency

PHONE : 651/297-8610

SUBJECT : Enbridge Pipe Line Company 34 Inch Crude Oil Line

DOT-RSPA-OPS
03 JUN 27 AM 8:38

A 34 inch diameter pipeline operated by Enbridge Pipe Line Company crosses northern Minnesota. Since the July 4, 2002, Cohasset rupture this pipeline has been under Federal order to operate at reduced pressure to reduce the risk of additional leaks or ruptures. Enbridge may ask the Federal Office of Pipeline Safety for permission to resume normal operating pressures in order to increase the volume of crude oil transported by the pipeline.

In my role as supervisor of the Emergency Response Team of the Minnesota Pollution Control Agency (MPCA), I urge both the Federal and Minnesota Offices of Pipeline Safety to be extraordinarily cautious in considering increased pressures in this line, given the spill history of this pipeline and the very sensitive route of the line across Minnesota.

MPCA senior emergency response staff have been involved with spills from the 34 inch Enbridge line since the 1970's. The option that would be most protective of the public's safety and the environment would be replacement of all or major segments of this 34 inch line. Short of that, we are comfortable with continued operation of the 34 inch line at reduced pressure. We are not confident that internal inspections are sufficient to prevent additional spills. Hydrostatic pressure testing, coupled with follow-up internal inspections, might provide sufficient assurance to allow increased operating pressures.

There are four major petroleum pipelines in Minnesota. Enbridge has pipelines as large as 48 inches in diameter running across northern Minnesota. The Enbridge pipelines carry mostly Canadian crude oil through some of the most sensitive environment in Minnesota. They also run through heavily populated neighborhoods, under and near the Mississippi River, and through a number of tribal lands.

Recent examination of the in-line tool records from the after-Grand Rapids testing showed that a fault had been present at the Cohasset rupture site, but the fault was below the threshold criteria for further examination or repair.

Because of the Cohasset rupture, in-line testing of the 34 inch line was again done in 2003 using an in-line tool of increased capabilities. The A.O.Smith steel segment of the 34 inch line had dozens of features identified. The U.S. Steel segment had hundreds of features identified.

The 34 inch line between North Dakota and Superior passes under or near the Mississippi River, past a number of large and very important resource lakes, through bogs and wetlands, and through or near very many other sensitive features. There are frightening potential consequences of another 34 inch line failure if it occurs at or near the Mississippi River, within a tribal boundary, within a neighborhood or city, or under or near one of the major lakes.

Enbridge likely will request permission from federal OPS to resume full-pressure pumping based on the 2003 in-line testing and repairs. I urge that extraordinary caution be taken before granting such a request.

SJL:tf

---

[i] Spill statistic background information- Between January 1991 and December 2002 there were 23,301 spill or emergency incidents reported to MPCA. A majority of these incidents involved petroleum ranging from crude oil, to gasoline, to diesel fuel, to lubricating and waste oils. In the 1991 – 2002 period 4,593,053 gallons of petroleum were reported spilled in Minnesota

In contrast to long term storage tank or pipeline leaks, a sudden rupture of an underground pipeline or tank can be estimated with some accuracy. Between 1962 and 2003 there are 68 reports of large (>10,000 gallons) spills or ruptures from petroleum pipelines on MPCA records. The overall frequency and volume of pipeline ruptures has declined. About 22% (15) of these large pipeline ruptures involved the Enbridge 34 inch line. The 34 inch line is not 22% of Minnesota's linear pipeline distance or carrying capacity.

The largest pipelines can have the largest spills and ruptures. About 56 % of the reported volume of oil spilled in Minnesota in this period was from pipelines. The remainder of the oil spilled from trucks, trains, tanks, and other sources. Of the pipeline spills about 87 % was from the Enbridge 34 inch line.

[Great care needs to be taken in interpreting or extrapolating from historic spill reports. Most reports of aboveground spills, including pipeline ruptures, include an estimate of the spilled amount. However, reports that storage tanks or underground pipelines have leaked slowly usually do not include estimates of the lost product volume. Accurate estimation of an underground leak is very difficult, and is ultimately usually not very important in designing the needed cleanup. It is probable that at least as much petroleum has been leaked underground in Minnesota during that period as was spilled aboveground. For example, over 3 million gallons of petroleum have been recovered from under the Flint Hills Refinery, presumed to have leaked from tanks and underground lines during the 1960's to 1990's. Likewise, the pipeline operators have found a large number of locations where unknown volumes of oil have leaked over unknown periods. Those underground leaks are not included in the spill volumes cited above.]

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June 17, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursion over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J.R. Sobojinski /jef
John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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ENBRIDGE™

May 27, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

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Sincerely,

J R Sobojinski / jf
John R. Sobojinski

Attachment

c: David Bryson
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U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

June 5, 2003

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: Viking Station. Request for relief from operating pressure restrictions.
CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 3 System. The Order was issued in response to a failure that occurred on the line on July 4, 2002, and applied to Enbridge's 34-inch pipeline system constructed with pipe manufactured by U.S. Steel. On July 11, 2002, the Order was amended to allow Enbridge to return the pipeline to service provided the operating pressure at the failure location and at certain pump stations did not exceed 80% of the pressure at those locations at the time of the failure. The amendment further stipulated that these pressure restrictions would remain in effect until written approval for an increase was granted by the Central Region Director.

By letter dated, April 3, 2003, Enbridge requested approval of a modification to its Return-to-Service Plan for the 34" Line 3 System. The proposed modification requested that Enbridge be permitted to operate its Viking Station on Line 3. Enbridge stipulated that the maximum allowable discharge pressure would not exceed 330 psig and that operation of the Viking Station would not result in a pressure increase that would exceed the present pressure restrictions on the pipeline. Additionally, Enbridge requested that OPS allow the operation of the Donaldson Station on Line 3 at the pre-incident maximum allowable discharge pressure of 618 psig.

In discussions with Enbridge following this request, OPS related that we could not approve this request until the OPS/MNOPS review of data related to Enbridge's evaluation of the pipeline with the in-line, crack detection tool had been completed and a decision reached on the acceptance of the Return-to-Service Plan. Subsequently, Enbridge has more recently informed OPS that the proposal to operate the Viking Station is not contingent upon the proposed pressure increase at Donaldson Station.

OPS does not object to the operation of Viking Station at the pressure proposed in Enbridge's request and approves the operation of Viking Station at that pressure. However, OPS has determined the proposal to increase the pressure at Donaldson Station is not acceptable at this time and denies the Donaldson pressure increase.

If you have any questions in regard to this matter, please contact me at (816) 329-3800.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge Pipelines (Lakehead) L.L.C.
119 North 25th Street East
Superior, WI 54880-5247

Mr. Charles Kenow, MnOPS

Enbridge Pipelines (Lakehead) L.L.C.
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ENBRIDGE™

May 20, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There was one pressure excursion this past week. See the attached chart for details.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski /jjf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR
04/18/03	MP 1002	424 psig	1%	40 seconds	Pressure backed up when a Floodwood unit was stopped due to a power consumption.
05/19/03	PL	466 psig	5.42%	53 seconds	Sediment plugged the Clearbrook transmitter line causing a faulty reading.

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

Enbridge Pipelines (Lakehead) L.L.C.
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ENBRIDGE™

May 13, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

Enbridge Pipelines (Lakehead) L.L.C.
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April 29, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski / JH

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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April 29, 2003

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

Thank you for the opportunity to meet with you and your staff on April 22 to discuss our findings regarding the internal inspection of our 34-inch line using the UltraScan CD tool and our integrity management program to address stress corrosion cracking. As a follow up to this meeting and in response to your e-mail request of March 7, 2003, attached is a binder that contains responses to all outstanding requests for information from your department.

Upon completion of your review of this documentation, and in consideration of all previous materials provided to you, we again respectfully request the approval of our "34-inch Return-to-Service Plan", as previously submitted. We remain confident that we have demonstrated all reasonable measures are being taken to safely return this portion of our system to full service.

If you should have any questions or concerns regarding any of the information submitted, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachment

c: H. Noel Duckworth
John Hayes
Joel Kanvik
Walter Kresic
Art Meyer
Greg Sevick
Dan Tutcher
Ron Weist

Enbridge Pipelines (Lakehead) L.L.C.
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April 22, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There was one pressure excursion this past week. See the attached chart for details.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski /gf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

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PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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April 15, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski /jrf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

Recd 4/24/03

MINNESOTA DEPARTMENT OF PUBLIC SAFETY

Office of Pipeline Safety

444 Cedar Street, Suite 147, St. Paul, Minnesota 55101-5147
Phone: 651/296-9636 FAX: 651.296.9641 TTY: 651/282-5555
Internet: http://www.dps.state.mn.us

Alcohol & Gambling Enforcement
Bureau of Criminal Apprehension
Capitol Security
Driver & Vehicle Services
Emergency Management/ Emergency Response Commission
State Fire Marshal/ Pipeline Safety
State Patrol
Traffic Safety

April 9, 2003

Case No. 003656-1

Ivan Huntoon, Central Region Director
Federal Office of Pipeline Safety
901 Locust Street, Room 462
Kansas City, MO 64106

Dear Mr. Huntoon:

The Minnesota Office of Pipeline Safety (MNOPS) submits the following written comments in reference to Enbridge Energy Company's 34 inch pipeline Return to Service Plan, the information that has been submitted to support that plan, and the mitigative efforts that have been undertaken to help ensure the operational integrity of that pipeline.

Enbridge's response to the OPS Information Request for CPF 3-2002-5017H, dated January 29, 2003, provides a substantial amount of current information related to internal inspection activity, pressure cycle information, and defect growth analysis. While quite comprehensive, this information yields further questions and concerns about the operational integrity of the pipeline.

The information submitted in response to Question #1 of the Information Request, indicates the company had generally favorable results identifying longitudinally oriented defects through the use of the PII UltraScan crack detection tool. However, a closer analysis of the information reveals that, in addition to defects tending to be longer than what the tool called out, there were a substantial number of defects identified during field examination that were not called out by the tool. Some of these were in excess of the tool's threshold reporting requirements, and several were in excess of other defects called out and reported by the tool. In addition, some defects that were reported as internally connected were determined during field examination to be externally connected, and some that were reported as externally connected, were determined during field examination to be internally connected.

The internal inspection results generally do not provide estimated depths of reported defects, although depth is one of the criteria used to characterize the defect. The absence of this information seriously inhibits the ability to evaluate tool reliability and accuracy.

Our overall conclusion from the information submitted for the pipeline segments between Gretna and Clearbrook, is that the tool shows improved capability for identifying defects. It has not, however, been demonstrated to have sufficiently reliability to allow for a return to operating conditions that were in effect prior to the July 4, 2002 rupture near Cohasset, Minnesota.

The segment of pipeline between Clearbrook and Superior has been the subject of similar inspections, and a large number of anomalies have been investigated and repaired since the beginning of 2003. While no formal results have been provided by Enbridge to date, MNOPS has had the opportunity to witness a number of defect assessments, and Enbridge field personnel have been forthcoming with their findings. In addition to a large number of seam defects, a substantial amount of Stress Corrosion Cracking (SCC) has been identified. Again, the tool results generally did not provide estimated depths of reported defects, which severely limits the ability to evaluate tool accuracy and reliability.

Additional defects were identified beyond those reported by the tool in this section as well, and the SCC in particular, was typically much more extensive than what had been called out by the tool. While the initial round of investigations is nearly completed for this section, it has been mentioned there could be an additional 100 SCC digs coming for the remainder of the year.

In general terms, the majority of tool reported defects between Gretna and Superior have been on A.O. Smith pipe, as opposed to U.S. Steel pipe, and most of the investigations on U.S. Steel pipe have been for SCC, or "crack field" indications, as they are reported by PII. This yields a number of questions related to analysis and evaluation of tool results. It seems possible that the toe cracks in the U.S. Steel pipe may be more difficult to discriminate due to the defect occurring in the weld upset zone, where other geometrical features exist, compared to the A.O. Smith pipe, where the defect typically occurs in the center of the weld seam. It also seems odd there was no SCC identified on the section of pipeline between Gretna and Clearbrook, although it's not clear that it was even looked for during field examinations. The coating condition is fairly consistent along the pipeline's entire length, which is predominantly sagging and wrinkled, at least where it has tape coating.

The Enbridge response also presents a great deal of information on pressure cycles and fatigue growth analysis. The fatigue growth analysis uses the Rainflow pressure cycle counting process over a two month period during 2001 as being representative of pipeline operations over a much longer operating history. We question whether this is appropriate given the actual operating history. It is our understanding that this particular pipeline was "run hard" early in its operating history, probably until the March 1991 rupture near Grand Rapids. Following that rupture, pressure restrictions were placed on the pipeline, and hydrostatic testing was required. The pressure restrictions were removed around 1998, following internal inspections with the PII Elastic Wave tool, until the rupture near Cohasset occurred, on July 4, 2002. We believe a fatigue growth analysis that fails to consider the various operating pressure regimes to which this pipeline has been subjected to is inherently flawed, and adds further uncertainties into a process that is already subject to a number of ambiguities.

The fatigue growth analysis is governed by a number of factors, as outlined in Enbridge's response to Question #10. While the response is only in draft form, we have to initially question why it is dated January 23, 2003, when OPS specifically asked for reports that were used for Enbridge's presentation on December 17, 2002. It also references additional input being sought from BMT Fleet Technology Limited, and CC Technologies, but does not present any of that information in the response. This information is necessary in order to properly evaluate the analysis.

Of particular interest in the fatigue growth analysis is the use of the constants "C" and "n", which are reported to characterize the propensity for crack growth in a particular material, in a particular environment. While we cannot doubt the expertise of the individuals performing the analysis, we have to question how certain they can be in their assumptions when "C" values have changed from 95E -34 to 9.82E -16, and "n" values have changed from 6.4 to 2.263. At best, it indicates a high degree of uncertainty goes into these calculations. Couple this with over simplification of pressure cycle spectrums over the course of time, varying eccentricity levels which have been demonstrated to be as high as 50% (the analysis uses .2 consistently), and a host of variables specific to individual locations, and it seems reasonable that the conclusions drawn are highly subjective in nature.

The Enbridge response also compares internal inspection capability for identifying defects, compared to hydrostatic testing's ability to identify defects. There is no argument that internal inspection is capable of finding defects that would not fail under a hydrostatic test. This was even demonstrated with the Elastic Wave tool. The concern is with defects that are nearer to failure. Internal inspection has shown the ability to miss these defects, whereas hydrostatic testing will not. We agree with the concern that hydrostatic testing can grow smaller defects. However, we cannot accept the argument against hydrostatic testing due to the possibility of pressure reversal. If our understanding of this concept is correct, pressure reversals imply a significant population of defects near failure. Our position is that it is much better to fail these defects with water, than product.

We acknowledge the tremendous amount of effort and expertise that has been committed by Enbridge to operate this pipeline safely and effectively. In addition to the known historical defects in the longitudinal seam and other documented pipeline safety risks for leaks and ruptures, the current challenge now includes SCC. The maintenance welding over an extended period of time also needs to be considered. It is our opinion that, even with the improved capabilities for crack detection through internal inspection, the risk of injurious defects to exist is too high to allow for any pressure increase at this time. We firmly believe the pressure restriction reduces pressure cycle intensity, allows an increased time to failure, provides for an increased likelihood that the failure mode would be a leak, rather than a rupture, and ultimately provides for safer operation for the remainder of its useful life.

While we believe the most prudent measure is a permanent pressure restriction, compelling arguments will no doubt be made to the contrary. If an alternative course of action is chosen, we have no choice but to argue that confirmatory hydrostatic testing be conducted, with subsequent crack detection inspections. We will still maintain that the adverse affects of increased pressure cycle intensity will reduce safety margins to unacceptable levels, but assuming the pipeline is tested without failure, we would have the additional assurance that internal inspection did not miss a deleterious defect.

We must also recognize that, in addition to the numerous items requiring further information and clarification, the National Transportation Safety Board (NTSB) may have recommendations concerning the future operation of this pipeline as a result of their investigation.

We appreciate the opportunity to offer our input with regard to this matter, and look forward to future discussions concerning the safety of this pipeline. If you have any questions, please contact Ron Wiest or Brian Pierzina.

Prepared by,

Brian E. Pierzina

____________________ Brian Pierzina, Senior Engineer

Reviewed by,

Ronald J Wiest

____________________ Ronald J. Wiest, Chief Engineer

For the Minnesota Office of Pipeline Safety,

Charles R Kenow

____________________ Charles R. Kenow, Administrator / RJW

cc: Leonard Steiner, FOPS

Comp'l Reg
Phil
Dave
Ivan

Enbridge Pipelines (Lakehead) L.L.C.
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www.enbridgepartners.com

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ENBRIDGE™

April 8, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski /jf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
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John R. Sobojinski
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ENBRIDGE™

April 1, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

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If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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john.sobojinski@enbridge-us.com

ENBRIDGE™

March 18, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

J R Sobojinski / bf

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

'03 MAR 24 9:15

DOT-RSPA-OPS

Line 3 Pressure Excursions

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John R. Sobojinski
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ENBRIDGE™

March 11, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

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Sincerely,

J.R. Sobojinski /jef

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

VIA TELECOPY

July 7, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 4 System. This action followed a failure that occurred on 34" diameter pipe near Milepost (MP) 1003.1 on July 4, 2002.

Please note that the Order was issued under CPF No. 3-2002-5017. By this letter I am correcting that CPF No. Please reference CPF No. 3-2002-5017H in all future correspondence.

The Order requires that prior to returning the pipeline to operation, Enbridge must file a written plan with OPS for OPS' review and approval. The written plan is to include measures that must be taken to provide for the safe return to service and the continuing safe operation of the pipeline. Item 4 of the Order stipulates that the Regional Director may approve the elements of the plan incrementally.

Enbridge has proposed through discussions with OPS staff at the accident investigation site and with me repair procedures that require filling the isolated section of pipe associated with the failure site with crude oil. Additionally, by your letter dated July 7, 2002, Enbridge has submitted a request to OPS to allow the transfer of crude oil into the isolated pipeline section for the purpose of effecting the repair of the pipeline. The use of Weld-Plus End fittings to join the replacement section of pipe to the existing piping requires that crude oil be present at the site during the welding of these fittings. In transferring crude oil through your pipeline system to refill this pipeline section, the pressures imposed on the pipeline would be significantly lower than those

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Legend:

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DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

amending the maximum operating pressures for Line 3 upstream of Clearbrook as follows:

Station	Pressure
Gretna	437 psig
Donaldson	494 psig
Plummer	442 psig

We further request that Enbridge provide the Central Region Office a tabulation of the occurrences in which these maximum operating pressures are exceeded. The information should include the dates, pressures and cause of the occurrence and should be submitted on a weekly basis.

This approval is with the understanding that OPS and MNOPS will continue to review additional pressure restrictions and/or other measures that may be required as a result of new information provided by the analysis of the failed pipe section and new information on any other items that may have been contributing factors to the failure.

If you have any questions in regard to this matter, please contact me at (816) 329-3800.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

Mr. Charles Kenow, MnOPS

experienced in normal operation. Following the completion of the repair welding, the pipeline will remain in a shut down state, pending the determination and approval of additional provisions of Enbridge's written plan for return to service.

We have reviewed your request and find it to be acceptable. Therefore, you may return the pipeline to service as you have proposed for the purpose of repairing the pipeline.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John R. Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

Enbridge Pipelines (Lakehead) L.L.C.
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John R. Sobojinski
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john.sobojinski@enbridge-us.com

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March 4, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
Date	**Location**	**Maximum Pressure**	**% Over Allowable**	**Duration Allowable was Exceeded**	**Cause of Occurrence**
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

GF	Gretna	DR	Deer River
DN	Donaldson	MP 1002	Midline transmitter at the rupture site
PL	Plummer	FW	Floodwood
CR	Clearbrook	PR	Superior

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February 25, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions

Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
12/05/02	MP 1002	424 psig	1%	17 seconds	Slow acting PCV at PR

Legend:

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February 11, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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ENBRIDGE™

January 28, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R Sobojinski / jef

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

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Date	Location	Maximum Pressure	% Over Allowable	Duration Allowable was Exceeded	Cause of Occurrence
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Legend:

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Copies Registry
Phil

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January 21, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski /jef

John R. Sobojinski

Attachment

c: David Bryson
John Hayes

Line 3 Pressure Excursions					
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January 14, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attacment

c: David Bryson
John Hayes

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ENBRIDGE™

January 7, 2003

'03 JAN 13 7

DOT-RSPA-OPS

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 482
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPT No. 3-2002-5017H

In accordance with your letter dated December 2, 2002, Enbridge will provide your office with a weekly tabulation encompassing all occurrences in which the agreed upon maximum operating pressures were exceeded. There were no pressure excursions over allowables this past week; therefore, the attached chart remains the same.

If you have any questions regarding the information provided, or on any other matters, please contact me at (218) 725-0505.

Sincerely,

John R. Sobojinski

Attacment

c: David Bryson
John Hayes

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U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

December 31, 2002

John Sobojinski
Manager, US Compliance & Risk Management
Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

RE: Information Request relating to CPF 3-2002-5017H

Dear Mr. Sobojinski:

Thank you for the information Enbridge provided during the meeting in Kansas City on December 17, 2002. While the presentations were informative, additional specific information is needed for OPS to evaluate Enbridge's conclusions and proposed return-to-service plan. Please submit the following items at your earliest convenience:

1. Complete documentation of US/Canadian border to Clearbrook inspection digs which were completed as a result of the PII Ultrascan CD tool run of 2001; including, but not limited to, pipe inspection reports, field NDE results, PII report of the anomaly, any repairs made, etc.

2. Complete PII Ultrascan CD survey report of 34-inch US/Canadian border to Clearbrook line section.

3. Complete PII Ultrascan CD survey report of 34-inch Clearbrook to Superior line section once completed by PII.

4. Report of PII results of known linear defects which are under previously installed sleeves for the 34-inch US/Canadian border to Clearbrook line section. Also include the inspection data gathered at the time of sleeve installation (i.e. field measurements of the defects, inspection and NDE reports, etc.) Please also submit similar data for the Clearbrook to Superior line section when it becomes available.

5. Samples of PII scans of various defects which would normally be excavated (i.e. crack-like, notch-like, etc.)

6. Written documentation of the repair process, including specifications on how the anomalies are evaluated in the field, and the criteria used to determine need for repair. Also describe which methods are used to repair defects confirmed upon excavation and evaluation in the field.

7. Written documentation describing the process Enbridge uses to determine which anomalies are excavated based on the PII Ultrascan CD survey report.

8. Written documentation describing the process whereby pressure cycles are counted. This should include sources of data, data analysis, counting procedures, etc.

9. Submit a listing of the pressure cycles in a tabular format as well as the graphs presented for Donaldson and Deer River pump stations. Please also include similar information for Clearbrook Station.

10. Copies of reports generated by third party consultants detailing the predicted crack growth calculations presented at the meeting on December 17, 2002.

11. Detailed information on predicted versus field measured defects on previous Enbridge Ultrascan CD runs. Please address location of defects (ID, OD, midwall, seam, pipe body, etc.), type of weld seam, type of defect, etc. If applicable, address any defects that may have been cut-out to confirm the size of predicted anomaly using metallurgical analysis. Also, include specific information on the Ultrascan CD tool's historical capability of finding and describing ID cracks at the toe of weld seams.

12. Has the Ultrascan CD tool been run multiple times in the same pipe where the time between subsequent runs was in years? If so, please include a discussion of the tool's historical capability as an assessment tool in maintaining the integrity of pipelines (based on multiple tool runs) which exhibit crack-like flaws that grow in-service.

13. Provide an analysis modeling the Cohasset failure (with known initial notch dimensions) using the actual cyclic operating history (including previous hydrotests, pressure restrictions, etc.) at this location.

14. Provide an analysis of the effects of a hydrotest, performed after the Ultrascan CD tool run, on verifying the integrity of 34-inch US Steel pipe. The analysis should consider pressure test scenarios at various stress levels (e.g. 90% SMYS, "spike" test at 100% SMYS, etc.)

15. Provide an analysis demonstrating the sensitivity of predicted crack-life to the number of cycles applied, specific to Enbridge's operation of the 34-inch pipeline.

16. Provide an analysis demonstrating the sensitivity of predicted crack-life to the amount of misalignment of the plate edges at the longitudinal weld seam.

17. Provide a statement of the Ultrascan CD tool's capability of finding and describing misalignment of the plate edges at the longitudinal weld seam. With this also a statement of the tool's capability of finding and describing crack-like defects where misalignment of the plate edges is present. If there is historical data supporting the tool's capability where misalignment was encountered, please forward.

If you have any questions concerning this request for information, please contact me or one of my staff at (816) 329-3800.

Sincerely,

for Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Charles Kenow
Minnesota Office of Pipeline Safety

Dan Tutcher
Enbridge Energy Company, Inc.

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

December 2, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: Request for relief from operating pressure restrictions, CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 3 System. The Order was issued in response to a failure that occurred on the line on July 4, 2002, and applied to Enbridge's 34-inch pipeline system constructed with pipe manufactured by U.S. Steel. On July 11, 2002, the Order was amended to allow Enbridge to return the pipeline to service provided the operating pressure at the failure location and at certain pump stations did not exceed 80% of the pressure at those locations at the time of the failure. The amendment further stipulated that these pressure restrictions would remain in effect until written approval for an increase was granted by the Central Region Director.

By letter dated November 11, 2002, and in subsequent discussions with staff, Enbridge has provided additional information on its operations and past pressure history and requested that the operating pressure restrictions be limited to 85% of a higher operating pressure recorded preceding the failure as an interim measure pending review and approval of the full return-to-service plan. The higher maximum operating pressures were requested for the pipeline sections from Gretna to Clearbrook to alleviate operational difficulties being experienced at the lower pressure limits.

We have reviewed the Enbridge request. We will not approve your request to operate at the 85% level. However, we find that it is reasonable to allow Enbridge to operate at 80% of the higher operating pressures recorded prior to the failure at the requested locations. Therefore, we are

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John R. Sobojinski
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January 29, 2003

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

On July 8, 2002 Enbridge submitted to the OPS its return-to-service plan as directed by the Corrective Action Order issued on July 5, 2002. Since that time, in the full spirit of cooperation, Enbridge has provided your office with a significant amount additional information which clarifies and further details our return-to-service plan. We have also sponsored two separate face-to-face meetings in Kansas City to present specifics related to our integrity management program and the processes and tools used to identify and mitigate crack like defects within our system.

Your letter dated December 31, 2002 has requested additional specific information in order to further review and evaluate our proposed return-to-service plan. Each of the issues raised in your letter has been comprehensively addressed, with the exception of your item No. 3. The PII UltraScan CD report for the 34-inch Clearbrook to Superior line section has not been completed. PII has provided Enbridge preliminary data and Enbridge has begun field investigation activities based on this preliminary information. Once completed by PII, the inspection final report will be forwarded to accommodate this request. All other supporting information has been included in the attached package.

Upon completion of your review of this information, we again respectfully request the removal of the existing pressure restrictions on the 34" US Steel pipe upstream of Clearbrook Station, to the Canadian border. We are confident that we have demonstrated that all reasonable measures have been taken to safely return this portion of our system to full service.

In addition, we also reiterate our request for approval of our "34-inch Return-to-Service Plan" as previously submitted. This plan details the mitigative actions which have already been taken, as well as future measures which will ensure the integrity of all 34" US Steel pipe in our system. Enbridge continues to be a safe and responsible operator and is dedicated to ensuring the continued safety of both the public and the environment.

If you should have any questions or concerns regarding any of the information submitted, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes
Joel Kanvik
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

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November 11, 2002

UPS – NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

In accordance with Section 8.B of the amended Corrective Action Order identified above, Enbridge respectfully requests approval to increase the operating pressure on its 34" Line 3 pipe between the Canadian border and Clearbrook, Minnesota from its current operating level of 80% of discharge pressure at the time of failure to, 85% of the highest operating pressure reached during the 30-day period prior to the failure. These pressures remain considerably lower than MAOP at these locations prior to the July 4, 2002 incident (see attachment 1) and are an interim step prior to final approval for removal of the pressure restrictions and our return to full service. This request is based on mitigative actions taken by Enbridge in accordance with our 34" Return-to-Service Plan, Section 3.1 Mid Term Plans, which provide for a safe return to normal operations of the pipeline. These actions include:

- Completion of the analysis of crack data upstream of Clearbrook Terminal to the Canadian border on the 34-inch Line 3 pipe. The information was initially obtained during a 2001 crack detection tool run.
- Completion of the field investigations resulting from the 2001 crack detection tool run on all US Steel pipe sections upstream of Clearbrook Terminal.
- Completion of all repairs associated with field investigations on all US Steel pipe sections upstream of Clearbrook Terminal. Only five minor anomalies were confirmed upon field investigation of the US Steel pipe:
  - 2 pipe laminations
  - 1 internal gouge 5% deep
  - 1 shallow, external crack in the long seam weld cap that did not penetrate nominal wall, ground out
  - 1 external shallow gouge 4% deep.

  None of the five anomalies met the requirements for sleeving according to ASME B31.4 or our Operating & Maintenance Procedures Manuals.

In addition to these mitigative efforts, operating at the proposed 85% level would result in significant improvements in Line 3 operation upstream of the Clearbrook and Line 4 downstream of Clearbrook. Such improvements include:

- Considerably fewer unit lockouts, high holding pressure shutdowns and column separations.

- Reduction in the need for unscheduled shutdowns downstream of Clearbrook when changing operations from a delivery/injection mode at Clearbrook to delivery straight through to Superior.
- Pumps would be operating in a more efficient range for their design.

All the above currently contribute to cycling stresses due to transient pressure waves as well as SCADA line shutdowns (large magnitude pressure cycles). Both Line 3 and Line 4 would operate in a much more stable manner with fewer pressure cycles as a result of modifying the current pressure restrictions.

Based on our ongoing pipeline integrity programs, we believe that these sections of mainline can be safely returned to normal operations. As an interim measure prior to final approval for removal of pressure restrictions on the 34" US Steel pipe upstream of Clearbrook, Enbridge hereby requests that the current pressure restrictions on the aforementioned pipe be reduced to 85% of the highest operating pressure reached during the 30-day period prior to the failure.

Should you have any questions or comments regarding this request, please contact me at your earliest convenience.

Sincerely,

John R. Sobojinski

Attachment

c: David Bryson
John Hayes
Joel Kanvik
Walter Kresic
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

Attachment 1
November 11, 2002

	A	B	C	D	D1		E
Station	BMDP	Current BMDP (80% of F)	Highest Pressure in 30 days prior to Jul 4	85% of C	*	Max. Duration of each D1 Event	Pressure @ Time of Rupture
Gretna	682	380	546	464	9	1 hour	475
Donaldson	618	462	617	524	35	> 24 hours	577
Plummer	570	343	553	470	9	4 hours	429

* Number of times (D) was reached or exceeded during the 30 days prior to the July 4 incident.

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

VIA CERTIFIED MAIL

November 8, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
1100 Louisiana
Suite 2950
Houston, TX 77002-7002

Re: CPF No. 3-2002-5017-H
Enbridge's Request to Return to Normal Operating Service
US-Canadian Border to Clearbrook Station

Dear Mr. Tutcher:

Thank you for providing additional information relating to Enbridge's progress in fulfilling the requirements of the Corrective Action Order ("Order") during the October 29, 2002 meeting in Kansas City, Missouri. At the meeting and by letter dated October 29, 2002, Enbridge requested that the pressure restriction be removed on the 34" pipeline segment from the U.S.-Canadian border ("international border") to Clearbrook Station. While Enbridge has made progress in addressing integrity issues on the 34" pipeline from the international border to Clearbrook, the Office of Pipeline Safety ("OPS") can not approve Enbridge's request at this time. OPS requires further information to adequately evaluate Enbridge's proposal to return to the previously established maximum operating pressure (MOP) for the international border to Clearbrook segment. The Office of Pipeline Safety also believes that additional measures may be necessary to more fully ensure the integrity of the pipe subject to the Order before returning the 34" pipeline to the normal operating pressures in place prior to the July 4, 2002 accident.

The reduced discharge pressures instituted as required by the Order were based on the operating pressures at the time of the July 4, 2002 incident. OPS believes that the mitigative actions taken thus far, including the evaluation and repair of anomalies completed in 2002 based on the Ultrascan CD in-line inspection of 2001, provide some increased assurance of the 34" pipeline's integrity for the segment from the international border to Clearbrook Station. Therefore, an incremental increase in operating pressures may be permissible for this segment based on an analysis showing that a proposed increase is safe as described in Item 8B of the amended Order. If you have additional information justifying an incremental increase in operating pressure, please submit it to OPS' Central Region Office for consideration.

The Central Region Office will contact your staff to convey what additional information OPS requires as mentioned above. Thank you for your cooperation, and I look forward to meeting with Enbridge during the week of December 2, 2002 for additional discussions of your pipeline operation and return-to-service plan.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

CPF 3-2002-5017

Enbridge Pipelines (Lakehead) LLC
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November 4, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

Re: Enbridge Line 3/Line 4 34-inch Integrity Management Program

As a follow-up to the meeting we had last Tuesday in Kansas City, we sent you a copy of the integrity program presentation provided by Walter Kresic and Dave McNeill. Our intention at the meeting was to describe the engineering analysis results that demonstrate the Enbridge 34-inch pipeline between Gretna and Clearbrook is safe to operate at its normal operating pressures. The following points reiterate our conclusions that were presented at the meeting:

- Based on information gathered thus far, the failure at MP 1002.73 was caused by fatigue that initiated at a railroad shipment induced stress concentrator. The failure has characteristic crack dimensions and properties that are very similar to previous failures on the pipeline.

- Virtually every form of integrity prevention, monitoring, mitigation and analysis approach has been conducted on the 34-inch pipeline through its years of operation. Tremendous learnings have been gathered through this period and our learning process is ongoing. The techniques and processes for ensuring a safe pipeline are at our disposal and we are committed to ensuring the resources are accurately applied.

- We have validated that in-line inspection is the most precise method for managing crack concerns on the 34-inch Line 3/Line 4 pipeline. Our validation activities include several thousand miles of inspected pipeline experience, hundreds of field investigative excavations, confirmation hydrotest, laboratory and bench-scale qualification tests, numerous inspection tool vendor audits, information sharing with other companies, researchers, and interested parties and various other activities that we conduct as a core function within our Company.

- There have been several important instances where crack detection in-line inspection did not identify to a full extent the criticality of particular defects during Enbridge programs. The reasons for this have been related to the vendor's process for managing crack detection data rather than an inability of the technology to identify defects. These circumstances were unusual and rare and in each case led to significant improvements to how we use the technology. We are still investigating if the MP 1002.73 failure was in some way related to a tool performance gap.

- In our experience, both the PII Elastic Wave tool and the PII Ultrascan CD Tool are able to provide accurate crack detection information. Considering the number of sensors, data storage and processing capabilities, modern electronics design, robustness, and our validation efforts, the PII Ultrascan CD Tool is able to identify smaller defects with greater precision than the Elastic Wave instrument.

- The crack inspection using the PII Ultrascan CD Tool was completed between Gretna and Clearbrook. There were very few relevant indications identified and we have completed investigative excavations for all US Steel pipe in this segment. The tool accurately predicted the defects and the field investigations did not reveal any significant cracking.

- A preliminary crack growth analysis for the Gretna and Clearbrook section indicates that the line will be safe from further critical crack growth for many years. We continue to refine our calculations and will be establishing a reinspection interval once these calculations are complete. The crack growth analysis is a complex, comprehensive activity that requires vast volumes of pressure history data and specialized knowledge of pipe crack behavior. Keifner & Associates have been applying their expert service to assist us with this effort and we are also working with other consultants to provide additional insights. Further, we are reviewing the validity of previous similar calculations conducted for this pipeline to ascertain whether the pressure data or equations used in the past were suitable.

In summary, we believe the failure at MP 1002.73 was caused by a mechanism that is similar to previous failures on this pipeline. We recognize crack detection in-line inspection as the most precise method of identifying crack defects in the Line 3/Line4 pipeline. We are aware that no technology is perfect but we manage this, not only through continuing to improve the ability of the technology, but also by ensuring revalidation intervals and data analysis processes are conducted with sufficient conservatism to counteract uncertainties.

In our presentation last Tuesday, we had hoped to communicate our learnings to you in a way that provided you with a comprehensive basis to judge our technical decisions. It was clear to us that you did not feel confident in our conclusions and therefore we would like to request a second meeting with you and your key personnel to discuss our integrity results and process in a more detailed fashion. We believe this would provide you and your staff an additional inside look into Enbridge's decision making methodology as well as an opportunity to identify more specifically any areas that you feel do not meet your requirements for defining pipeline safety.

Sincerely,

For

John R. Sobojinski

c: David Bryson
John Hayes
Joel Kanvik
Dave McNeill
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

Enbridge Pipelines (Lakehead) LLC
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John R. Sobojinski
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U.S. Compliance & Risk Management
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ENBRIDGE™

October 29, 2002

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

Enbridge Energy was issued the above Corrective Action Order on July 5, 2002 (amended July 11, 2002), in connection with our pipeline failure near Cohasset, Minnesota on July 4, 2002. Enbridge Energy has complied with all existing terms and conditions of this Order.

We have submitted a Return-to-Service Plan that includes appropriate measures to provide for return to normal operating service, while continuing safe operation of our pipeline system. In consideration of the information presented by Enbridge Energy at our meeting on October 29, we respectfully request that the pressure restriction now in place be removed for all 34" diameter DSAW pipe manufactured by U.S. Steel and located upstream of the Clearbrook Pump Station (MP 909.1), between the Clearbrook Pump Station (MP 909.1) and the U.S.-Canada border (MP 773.72), allowing Enbridge Energy to resume normal operations. All other aspects of the Return-to-Service Plan, as submitted, will remain in effect.

Please contact me at your earliest opportunity regarding the status of this request.

Sincerely,

John R. Sobojinski

c: David Bryson
John Hayes
Joel Kanvik
Dave McNeill
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

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21 West Superior Street
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john.sobojinski@enbridge-us.com

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August 6, 2002

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

Enbridge has undertaken the installation of a pressure transmitter at the rupture location (MP 1002.7) to permit more accurate monitoring of the pressure at that location. This transmitter is equipped with communications that allows it to become a control point in the Line 4 operation. By utilizing this mid point transmitter, we can increase the maximum allowable discharge pressure of Deer River station to 528 psig, which is below 80% of the discharge pressure at the time of rupture, while still operating with less that 420 psig, or 80% of the pressure at time of rupture at the rupture location.

Following is a revised Appendix I to Enbridge's Line 4, 34-inch Return-to-Service Plan. The change from the original submission is an increase in the Base Maximum Discharge Pressure of Deer River station from 442psig to 528psig. This change is in compliance with the amended Corrective Action Order CPF No. 3-2002-5017H.

APPENDIX I

		A	B	C
	Station	**BMDP**	**New BMDP (80% of C)**	**Pressure @ Time of Rupture**
Line 3	Griffith	682	380	475
	Donaldson	618	462	577
	Plummer	570	343	429
Line 4	Clearbrook	759	562	703
	Deer River	702	528	663
	Floodwood	608	478	597
MP 1002.7				525

Please contact me at (218) 725-0505 with any questions or comments.

Sincerely,

John R. Sobojinski

c: David Bryson
John Hayes
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher
Law

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 13, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, Texas 7002-7002

CPF_3_2002_5017H

Dear Mr. Tutcher:

We received your letter dated August 6, 2002, concerning the installation of a pressure transmitter at the rupture location(MP 1002.7 on the Clearbrook Pump Station to Superior Terminal segment of the 34"- diameter Line 4 pipeline) to permit more accurate monitoring of the pressure at that location. The letter confirms a verbal conversation between John Sobojinski and Donald Moore(OPS General Engineer) concerning maintaining the 80% pressure restrictions imposed by the Corrective Action Order and still allowing a pressure increase at your Deer River Station. We have reviewed the information submitted and we do not object to raising the pressure on this segment. The revised Appendix I will be inserted in Enbridge's Line 4, 34-inch Return to Service Plan. The operating pressure restrictions as imposed will remain in effect for the remainder of this pipeline.

Thank you for your continued cooperation and prompt submittal of the pipeline integrity information.

Sincerely,

Donald E. Moore

Ivan A. Huntoon
for Director, Central Region
Office of Pipeline Safety

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21 West Superior Street
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ENBRIDGE™

July 18, 2002

FAX (816) 329-3831

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

As noted in earlier correspondence, Enbridge intends to provide the Office of Pipeline Safety with progress reports on activities relating to the "34-Inch Return-to-Service Plan".

One such activity currently underway is the placement of the new 36-inch Terrace III pipe into Line 4 service with an associated transfer of the 34-inch to Line 3 service between Clearbrook and Superior. This transfer will better address throughput requirements and optimize pump performance, while maintaining the current pressure restrictions on the 34-inch US Steel pipe. This transition is expected to occur in stages between August and October.

The operation of the 34-inch in Line 3 service will minimize the potential for operational upsets during internal inspection and is expected to result in conditions that would optimize battery life and data collection. Internal Inspection is expected to proceed in late October or early November with results to follow 30 to 60 days after completion of inspection.

We will, of course, continue to comply with all existing terms and conditions of the Corrective Action Order. Should you have any questions or comments, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachments

c: John Hayes
Joel Kanvik
Dave McNeill
Art Meyer
Greg Sevick
Mark Sitek
Dan Tutcher

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

July 16, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 7002-7002

CPF No. 3-2002-5017H

Dear Mr. Tutcher:

Enclosed is the original letter which was faxed to you on July 7, 2002 for your files. This letter provided approval to return the 34" Line 4 to service for the purpose of effecting the repair at the July 4, 2002 failure site. It also corrected the CPF number on the Corrective Action Order from CPF 3-2002-5017 to CPF 3-2002-5017H as the reference number for all future correspondence.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

VIA TELECOPY

July 7, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 4 System. This action followed a failure that occurred on 34" diameter pipe near Milepost (MP) 1003.1 on July 4, 2002.

Please note that the Order was issued under CPF No. 3-2002-5017. By this letter I am correcting that CPF No. Please reference CPF No. 3-2002-5017H in all future correspondence.

The Order requires that prior to returning the pipeline to operation, Enbridge must file a written plan with OPS for OPS' review and approval. The written plan is to include measures that must be taken to provide for the safe return to service and the continuing safe operation of the pipeline. Item 4 of the Order stipulates that the Regional Director may approve the elements of the plan incrementally.

Enbridge has proposed through discussions with OPS staff at the accident investigation site and with me repair procedures that require filling the isolated section of pipe associated with the failure site with crude oil. Additionally, by your letter dated July 7, 2002, Enbridge has submitted a request to OPS to allow the transfer of crude oil into the isolated pipeline section for the purpose of effecting the repair of the pipeline. The use of Weld-Plus End fittings to join the replacement section of pipe to the existing piping requires that crude oil be present at the site during the welding of these fittings. In transferring crude oil through your pipeline system to refill this pipeline section, the pressures imposed on the pipeline would be significantly lower than those experienced in normal operation. Following the completion of the repair welding, the pipeline will remain in a shut down state, pending the determination and approval of additional provisions of Enbridge's written plan for return to service.

We have reviewed your request and find it to be acceptable. Therefore, you may return the pipeline to service as you have proposed for the purpose of repairing the pipeline.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John R. Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge Energy Company, Inc.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

July 9, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2002-5017H

Dear Mr. Tutcher:

On July 5, 2002, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (Order) to Enbridge Energy Company, Inc. (Enbridge) requiring certain actions be taken to ensure the safe return to service of the Lakehead Line 4 System. The Order applied to Enbridge's 34-inch pipeline system constructed with pipe manufactured by United States Steel.

The Order required that prior to returning the pipeline to operation, Enbridge must file a written return to service plan with OPS for OPS' review and approval.

By letter dated July 8, 2002, from Mr. John Sobojinski, Enbridge has submitted a return to service plan to OPS for review and approval.

The DOT Office of Pipeline Safety and the Minnesota Office of Pipeline Safety (MNOPS) have reviewed the Enbridge plan and approve the plan to place the 34-inch Lines 3 and 4 back in service at the reduced pressures indicated in the Enbridge return to service plan. This approval is with the understanding that OPS and MNOPS will continue to review additional pressure restrictions and/or other measures that may be required as a result of new information provided by the analysis of the failed pipe section and new information on any other items that may have been contributing factors to the failure.

If you have any questions in regard to this matter, please contact me at (816) 329-3800.

Sincerely,

for Charles W. Miller II

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

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July 8, 2002

VIA FEDEX

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

Attached is a revised Appendix I for our "Line 4 – 34-inch Return-to-Service Plan". A careful re-examination of the batch line-up that will be required to run in Line 4 was recently completed. In order to address industry requirements in the near future, we have found it necessary to decrease the BMDP at Deer River to 442 psig to ensure that we operate under 420 psig at the site of the rupture. Appendix I therefore reflects a change in Line 4, column B, for Deer River (DR) from 478 to 442.

Should you have any questions or comments, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachment

c: John Hayes
Jay Johnson
Joel Kanvik
Dave McNeill
Greg Sevick
Mark Sitek
Dan Tutcher

APPENDIX I

	Station	A BMDP	B New BMDP (80% of C)	C Pressure @ Time of Rupture
Line 3	GF DN PL	682 618 570	380 462 343	475 577 429
Line 4	CR DR FW	759 702 608	562 **442*** 478	703 663 597
MP 1002.7				525

Note: The pressure at M.P. 1002.7 will be limited to 420 psi as a result of a base max discharge pressure at Deer River Station of 478 psi.

Column A = Base Maximum Discharge Pressure (BMDP) prior to the rupture.
Column B = 80% of the actual working pressure at the time of the rupture at the specified location.
Column C = Actual working pressure at the time of the rupture at the specified location.

* After a careful examination of the batch line-up that will be required to run in Line 4 and address industry requirements in the near future, we have found it necessary to decrease the BMDP at DR to 442 psig in order to ensure that we operate under 420 psig at the site of the rupture.

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ENBRIDGE™

July 8, 2002

FAX (816) 734-9063

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2002-5017H

In response to Item 3 of the recent Corrective Action Order, attached is "Line 4 – 34-inch Return-to-Service Plan", along with related attachments, for your review and approval. The plan provides details for items A-F where relevant.

As noted on page 8 of the Plan, Enbridge intends to provide the OPS with progress reports on the status of the activities outlined in the Plan. Enbridge will also provide updates to programs or initiatives that result from this work.

Upon completion of the return-to-service plan, Enbridge will provide a Reliability Assessment to the OPS presenting the findings and conclusions and outlining any operating or other changes that result from these findings.

Should you have any questions or comments, please contact me at your convenience.

Sincerely,

John R. Sobojinski

Attachment

c: John Hayes
Jay Johnson
Joel Kanvik
Dave McNeill
Greg Sevick
Mark Sitek
Dan Tutcher

ENBRIDGE

Line 4 – 34-Inch Return-to-Service Plan

For Submission to the OPS

July 08, 2002

PIPELINE INTEGRITY

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1.0 Executive Summary

On July 4, 2002 at approximately 00:15 MST a rupture occurred on the Line 4, 34-inch section of line at MP 1002.73 (approximately 7 miles downstream of the Enbridge Energy Limited Partnership's Deer River pumping station). Investigation into the exact cause of the incident is still underway; however, preliminary assessments indicate that the rupture was likely due to long seam failure.

The section of pipeline that failed has been subject to a high standard of integrity management over the past decade. These efforts have included a hydrostatic test of the pipeline in 1991; an independent analysis of operational reliability and integrity in 1994 following a failure in that year; an internal inspection of the pipeline section for cracks in 1996; an internal inspection for corrosion in 1998; an independent reassessment of operational reliability and integrity in 1998; and an internal inspection for dents in 2000. Results from these previous in-line inspections and field investigations, metallurgical studies, pressure cycling studies and reliability assessments have indicated that there is a negligible likelihood of a long seam failure. As a result, Enbridge views this failure as an anomaly and not representative of the integrity of the pipeline as a whole.

Enbridge has been advised that regulatory agencies will require a 20% reduction in operating pressures from those observed at the time of the rupture at all station locations which directly affect pressures on all segments of 34-inch pipe between Gretna and Superior manufactured by US Steel. It is also understood that a pressure reduction of twenty percent below that observed at the time of failure is required at the location of the rupture (MP 1002.7). While Enbridge does not agree with these restrictions, this has been included as a component of the return-to-service plan per this direction.

Subsequent to the rupture (and prior to the excavation and assessment of the cause of the pipeline failure) the DOT issued Corrective Action Order CPF No. 3-2002-5017H. The Corrective Action Order required Enbridge to submit a return-to-service written plan to the OPS and that each element of the plan be approved by the Director, Central Region, OPS before the line is returned to service.

This document was prepared for the OPS to serve as the return-to-service plan upon which subsequent investigation and mitigation programs would be conducted to verify the integrity of the 34-inch line segment. Key aspects of the plan include:

1. Implementation of a precautionary temporary pressure restriction until the exact cause of the failure has been determined and prudent remediative measures have been implemented to ensure the pipeline can operate safely at normal operating pressure.

2. A metallurgical assessment to determine the exact cause of the failure.

3. Completion of crack inspection from Clearbrook, MN to Superior, WI using the best available in-line crack detection technology.

4. Completion of a field investigation and repair program to evaluate and mitigate any crack or crack-like features identified as a result of the in-line inspection program (and/or other potentially injurious indications that are discovered as a result of the inspection).

5. Continuation of analysis and excavation programs on the 34-inch line upstream of Clearbrook based on a 2001 crack tool inspection of the Gretna to Clearbrook section of line.

6. Analysis of other local factors that may be unique to this location and that may have contributed to the failure at MP 1002.73.

7. Reanalysis of pressure cycling studies on the 34-inch line using current historical pressure cycling information.

8. Analysis of alternatives to reduce pressure cycling downstream of Clearbrook to determine if additional operational efficiencies may be possible.

9. Supplemental research on crack growth studies to better define inspection intervals for in-line crack inspections.

2.0 Historical Integrity Data / Results

In 1991 Enbridge entered into a program to conduct an assessment and mitigation program and to complete a reliability assessment of the 34-inch line between Gretna, Manitoba and Superior, Wisconsin. This was precipitated by a history of long seam leaks and ruptures culminating in the failure of the line in March of 1991 near Grand Rapids, Minnesota. An assessment of the failure history concluded that the primary cause of long seam failures on US Steel SAW pipe was pressure-cycle induced crack growth of rail shipment fatigue cracks. Over the last 11 years, Enbridge completed an extensive program of analysis, hydrostatic testing, in-line inspection, and operational assessment and evaluation to improve the operational reliability of the 34-inch pipeline.

Highlights of the program included a complete hydrostatic test of the 34-inch line; development of in-line crack detection technology; inspection and repair programs for the entire 34-inch line using in-line crack detection tools; and operational changes to decrease pressure cycling and water hammer affects on the section of line downstream of the delivery point at Clearbrook, Minnesota. In 1998 Kiefner and Associates completed an assessment of the effectiveness of the programs and concluded that the potential for in-service failures from defects that might grow through to a critical size as the result of pressure cycling was negligible.

The majority of the crack inspections on the 34-inch line were completed using the British Gas Mark II Elastic Wave inspection tool. In 2001 Enbridge completed an inspection of 17 miles of line upstream of Clearbrook using the PII UltraScan CD crack detection tool. As part of this work an additional 5 miles of data that overlapped previous Elastic Wave crack inspections was completed. The overlapping analysis was completed in an area where the Elastic Wave tool had previously discovered features in the long seam. No additional features were identified within the 5-mile section of line.

3.0 Immediate / Short Term Plans

Pressure Restrictions

The section of pipeline that failed has been subject to a high standard of integrity management over the past decade. These efforts have included a hydrostatic test of the pipeline in 1991; an independent analysis of operational reliability and integrity in 1994 following a failure in that year; an internal inspection of the pipeline section for cracks in 1996; an internal inspection for corrosion in 1998; an independent reassessment of operational reliability and integrity in 1998; and an internal inspection for dents in 2000. Results from these previous in-line inspections and field investigations, metallurgical studies, pressure cycling studies and reliability assessments have indicated that there is a negligible likelihood of a long seam failure. As a result, Enbridge views this failure as an anomaly and not representative of the integrity of the pipeline as a whole.

Enbridge has been advised that regulatory agencies will require a will require a 20% reduction in operating pressures from those observed at the time of the rupture at all station locations which directly affect pressures on all segments of 34-inch pipe between Gretna and Superior manufactured by US Steel. It is also understood that a pressure reduction of twenty percent below that observed at the time of failure is required at the location of the rupture (MP 1002.7). While Enbridge does not agree with these restrictions, this has been included as a component of the return-to-service plan per this direction. Appendix I details the necessary changes to operating pressures to meet the pressure restriction requirements at the affected stations.

Metallurgical Investigation

Once the pipe has been removed from the pipeline, Enbridge will continue to work with the National Transportation Safety Board (NTSB) to complete a detailed metallurgical evaluation of the pipeline to determine the cause of the failure. Enbridge will participate with the NSTB in developing assessment protocols and ensuring that relevant information regarding the pipe, the failure and / or the results of the analysis are relayed in a timely manner so as to allow the application of the learnings to any subsequent inspection and mitigation programs. Communication of the results of the metallurgical analysis will be critical to developing a program to assess the remaining 34-inch pipe downstream of Clearbrook. Success of subsequent in-line inspections and pressure cycling analysis are dependent on an understanding of the type of defects that are expected to be found and the morphology of those features. Metallurgical investigations generally take up to 6-8 weeks to complete the analysis and receive final inspection reports. By participating in the analysis and development of the protocols, Enbridge expects that sufficient information will be gathered early in the assessment process to allow Enbridge to proceed with other phases of the evaluation, inspection and mitigation program.

3.1 Mid Term Plans

In-Line Inspections

In 2001 Enbridge completed an inspection of the 34-inch line upstream of Clearbrook with a PII UltraScan CD inspection tool. Analysis was completed on 17 miles of the 34-inch line in order to complete the commitment to the OPS to inspect all of the 34-inch line between Gretna, Manitoba and Superior, WI. Enbridge considers the UltraScan CD tool to the best current technology on the market for detecting cracks in pipelines. This tool has improved detection capabilities due to increased sensor coverage, improved electronics and data storage capabilities, and improved analysis software for assessing inspection data. At the time that the crack detection program began on the 34-inch line in 1995 the Elastic Wave tool was the best available technology and was developed by British Gas and Enbridge in 1994 to non-destructively inspect and find axial flaws on the 34-inch line.

As part of the this plan, Enbridge intends to complete crack detection inspections on the 34-inch line between Clearbrook, MN and Superior, WI utilizing the UltraScan CD tool to detect and find linear features. Enbridge has made inquiries into the availability of crack detection tool with its vendor and have been informed that the UltraScan CD tool may be available as early as 2-4 weeks. Enbridge will proceed with the UltraScan CD inspection of the line between Clearbrook, MI and Superior, WI as soon as the inspection tool becomes available.

Upon receipt of the in-line inspection report, Enbridge will complete field assessment and repairs as required to address crack features that are discovered as a result. Enbridge will excavate all crack or crack-like indications that are discovered and, in accordance with Enbridge Operating and Maintenance Procedures and Standards, remove or repair those features that are confirmed to be cracks. In addition, any other injurious features that are discovered as a result of the in-line inspection will be repaired in accordance with Enbridge procedures. Attached in Appendix II are excerpts from the Enbridge Procedures Manual and Standards that outline the repair criteria. Initial inspection results are expected within 30 – 60 days following completion of the in-line inspection.

Excavation and repair programs will follow receipt of in-line inspection results. Due to previous crack inspections and hydrotest programs, Enbridge expects that a low number of features will be identified for excavation.

Analysis of Crack Data Upstream of Clearbrook

In 2001 Enbridge completed an ultrasonic CD tool crack inspection of the 34-inch line upstream of Clearbrook to complete the Enbridge commitment to inspect the entire 34-inch line. As part of this inspection, data for all of the 34-inch line was collected.

Enbridge will complete the assessment of the CD data and complete an investigation and repair program as noted in the previous section.

Hydrotest

Enbridge does not view hydrostatic testing as a prudent option due to the possibility of initiating or growing currently dormant features that would not grow through to failure. Following the 1991 hydrotests Enbridge experienced 2 failures within 2.5 years of the hydrotests. In contrast, the time to failure following the Elastic Wave inspection in 1996 was 6 years. Enbridge still believes that in-line inspection is the preferred option for finding and mitigating linear features in pipelines.

Analysis of Other Local Factors

The location of the failure was situated in a peat bog that is subjected to annual cyclical fluctuations in water levels. The 34-inch line through this bog is not constrained and is subject to some movement due to buoyancy. Recent pipeline construction has also occurred within the vicinity of the pipeline. Enbridge will assess these conditions to determine if they could have contributed to or initiated crack growth.

Complete Reassessment of Cycling and Fatigue Life Calculations

Upon receipt of the metallurgical investigation results, Enbridge will complete reassessment of the cycling and fatigue life calculations utilizing current historical operating data to determine if operating conditions may have been a factor.

Analysis of Ways to Further Limit Pressure Cycling Downstream of Clearbrook

Enbridge will undertake additional operational studies to evaluate operating conditions on the pipeline to assess whether there are additional operating efficiencies that could be implemented to help reduce cycling on the pipeline.

Evaluation of Coating / Cathodic Protection

In the Corrective Action Order No. CPF# 3-2002-5017H, the OPS indicated that Enbridge should consider in the plan all known or suspected factors in the failure. Preliminary assessments indicate that the rupture is likely due to a long seam failure and does not appear to be related to a corrosion defect. As a result, Enbridge does not anticipate the need to complete detailed evaluations of coatings or cathodic protection systems. In the event that a determination is made that corrosion was a relevant factor in the failure, Enbridge will undertake an analysis of the CP and coating systems to determine what role these factors played in the failure and to determine if any operating changes are warranted to prevent similar incidents.

3.2 Long Term Plans

Supplemental Research on Growth Studies to Better Define Crack Inspection Intervals

Enbridge has undertaken studies on crack growth to better understand growth rates to assist in the determination of crack detection inspection intervals. Enbridge will continue this Research and Development work and will apply the findings when evaluating the need for future crack inspections on the 34-inch pipeline. Enbridge believes that this work will not only benefit stakeholders along the Enbridge system but can be applied to the industry to improve the overall understanding of crack growth mechanisms and allow all pipeline operators to benefit from improved knowledge.

4.0 Follow Up Activities

Enbridge intends to provide the OPS with progress reports on the status of the above activities and to provide updates to programs or initiatives that result from the above work. If there are any changes that are required to the plans due to findings or new information that is received as part of the investigative work, Enbridge will notify the OPS prior to changing the course of work as outlined above.

Upon completion of the program Enbridge will provide a Reliability Assessment to the OPS presenting the findings and conclusions and outlining any operating or other changes that result from these findings.

APPENDIX I

APPENDIX I

	Station	A BMDP	B New BMDP (80% of C)	C Pressure @ Time of Rupture
Line 3	GF DN PL	682 618 570	380 462 343	475 577 429
Line 4	CR DR FW	759 702 608	562 478 478	703 663 597
MP 1002.7				525

Note: The pressure at M.P. 1002.7 will be limited to 420 psi as a result of a base max discharge pressure at Deer River Station of 478 psi.

Column A = Base Maximum Discharge Pressure (BMDP) prior to the rupture.
Column B = 80% of the actual working pressure at the time of the rupture at the specified location.
Column C = Actual working pressure at the time of the rupture at the specified location.

APPENDIX II

Purpose

Pipeline defects are categorized by type, severity and, in the USA, by location. Repair equipment and sleeving techniques are available for every type of defect that could be encountered.

NOTE: Where practical or when physical or environmental conditions make it difficult to properly install sleeves, it may be necessary to replace the pipe.

Guidelines

USA

High Consequence Areas

NOTE: Pipeline Integrity specifically identifies defects that are located in a High Consequence Area (HCA) to field employees.

Immediately repair defects in a HCA if:

- metal loss is >80% of nominal wall thickness
- calculation of remaining strength shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly
- a dent above the 4 and 8 o'clock positions on a pipeline (a) has any indication of metal loss, cracking or a stress riser, or (b) has a depth >6% of nominal pipe diameter
- Pipeline Integrity identifies an immediate concern

Within 60 days, complete evaluation and remediation in a HCA if a dent:

- above the 4 and 8 o'clock positions on a pipeline ≥NPS 12 has a depth >3% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.
- on the bottom of a pipeline has any indication of metal loss, cracking, or a stress riser

Within 180 days, complete evaluation and remediation in a HCA if:

- a dent at a girth weld or longitudinal seam weld on a pipeline ≥NPS 12 has a depth >2% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.
- a dent above the 4 and 8 o'clock positions on a pipeline ≥NPS 12 has a depth >2% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.

- a dent on the bottom of the pipeline has a depth >6% of the pipeline diameter
- calculation of remaining pipe strength shows a safe operating pressure less than the current established maximum operating pressure at the location of the anomaly
- an area of general corrosion has a predicted metal loss of >50% of nominal wall
- predicted metal loss >50% of nominal wall is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
- a potential crack indication when excavated is determined to be a crack
- corrosion is found on or along a longitudinal seam weld
- a gouge or groove is >12.5% of nominal wall

NOTE: If significant anomalous conditions are identified in a HCA, operating pressure must be temporarily reduced.

Repair Methods

Determine repair methods for pipeline defects by considering:

- size and shape of the defect
- roundness of the pipe
- presence of dents
- surface corrosion and interaction of corroded areas
- presence of cracks

Repair leaking and nonleaking pipeline defects by approved methods.

Reinforcement Sleeves

Clock Spring® composite sleeve devices are an acceptable alternative to the steel split sleeve for permanently repairing corrosion and dents (see Table 1 and Table 2).

NOTE: For more information, see 06-03-19, Installing Clock Spring Reinforcement Sleeves.

Temporary Repairs

Mechanical leak clamps and bolt-on sleeves are considered temporary repairs, unless they are welded permanently in place.

Inspect temporary repairs within 1 year of installation to verify the integrity of the repair.

Corrosion

No repair is required where the maximum depth of corrosion (either internal or external, or the sum of internal and external) is ≤20%.

Table 1 includes guidelines for evaluating whether corrosion with maximum depths >20% needs repair.

Gouges, Grooves and Arc Burns

Grinding is used to completely remove gouges, grooves and arc burns, and must be done to produce a smooth transition with the surrounding pipe surface. Use dye penetrant or magnetic particle inspection (MPI) to confirm that (a) gouges and grooves are removed and that (b) there are no cracks at the bottoms of the defects.

NOTE: For information on removing arc burns, see Book 4: Welding, Tab 02, Maintenance and Repair Welding.

Measure the minimum remaining wall thickness (WT) in the ground area. A sleeve is not required where grinding has reduced the nominal wall thickness by less than 40%, and the allowable length of grinding calculated in 06-03-10, Grinding Repairs is permissible.

Buckles

A buckle usually occurs at a sharp bend and is more localized than a dent. If a buckle exceeds the limits of pipeline deformity shown in Table 3, it must be cut out as a cylinder and replaced by another section of pipe.

Use a pressure-containment sleeve to repair buckles that do not exceed the limits of pipeline deformity.

Table 1
Corrosion Assessment and Repair

Location of Corrosion	Remaining Wall Thickness (RW) (% of nominal wall)	Allowable Longitudinal Length	Sleeve Repair Method
pipe body, external only	21% – 80%	see 06-04-02[1]	pressure-containment or Clock Spring®
	≤20%	none	pressure-containment
pipe body, internal or combined internal/external	51% – 80%	see 06-04-03[4]	pressure containment
	≤50%	none	pressure containment
HAZ[2], external only	51% – 80%	see 06-04-02[1]	pressure-containment or Clock Spring®
	≤50%	none	pressure-containment
HAZ[2], internal[3] or combined internal/external	51% – 80%	see 06-04-03[4]	pressure-containment
	≤50%	none	pressure-containment

NOTES

1 An Engineering Critical Assessment (ECA) using the RSTRENG effective area method can also determine the need to repair pits exceeding the allowable longitudinal length (see Engineering Standard D03-101, Pipeline Corrosion Assessment).
2 The heat affected zone (HAZ) includes the weld plus the area within 12.7 mm (0.5 in.) of the weld.
3 Rolled-in nonmetallic inclusions confirmed by ultrasonic inspection do not require repair.
4 Where internal and external corrosion exist together, use the allowable lengths for internal corrosion in 06-04-03, Tolerable Limits of Internal Corrosion.

Dents

Dent Depth Measurement

Calculate dent depth using the formula (see Figure 1):

$$B = D_{NOM} - D_{MIN} - \frac{(D_{MAX} - D_{NOM})}{2}$$

Where:

B = dent depth
D_{NOM} = nominal outside pipe diameter
D_{MIN} = pipe diameter measured with a pipeline caliper across the deepest part of the dent
D_{MAX} = pipe diameter measured 90° from the deepest part of the dent
A = measured dent depth using a straight edge

NOTE: Expose ovality and dents in the pipeline for a minimum of two days before taking measurements and determining whether to repair the pipe. With the object or intruding material removed, the pipe usually recovers part of its original contour.

e.g.

Where:

D_{NOM} = *30 inches*
D_{MIN} = *29 inches*
D_{MAX} = *30.75 inches*

$$B = 30 - 29 - \frac{(30.75 - 30)}{2} = 30 - 29 - 0.375$$

B = *0.625 inches*

Repair dents that contain defects (gouges, grooves, arc burns or cracks) by first evaluating the defect and then the dent.

Remove and repair the defect, if required, using the guidelines in 06-03-10, Grinding Repairs, and further evaluate using Table 2.

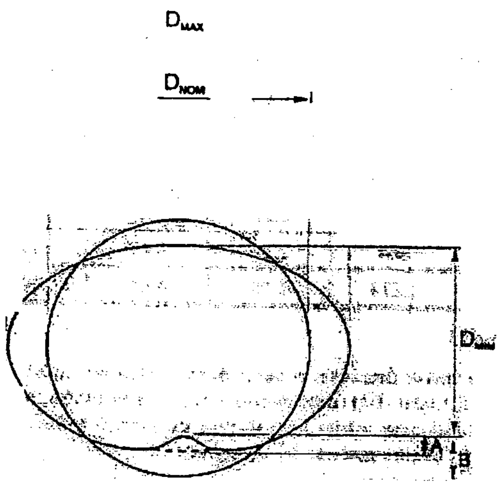

Figure 1
Method of Dent Measurement

Dents that exceed the limits of pipeline deformity in Table 3 may be repaired with a pressure-containment sleeve, but must be cut out before passing an internal inspection tool.

NOTE: Factory bends tolerate less of a dent or diameter reduction than Table 3 indicates for passage of internal inspection tools.

Table 2
Dent Assessment and Repair

Location of Dent	Depth of Dent	Sleeve Repair Method
pipe body	>6% of the outside diameter (OD)	pressure-containment or Clock Spring®
on a mill or field weld	>6 mm (¼ in.)	pressure-containment or Clock Spring®

Table 3
Limits of Pipeline Deformity

Nominal OD of Pipe		Maximum Dent or Depression in One Quadrant[1] (B)		Minimum ID and/or Ovality ID Limit[2] ($D_{MIN} - 2 \times WT$)	
in.	mm	in.	mm	in.	mm
12.75	324	0.94	23.9	11.0	280
16	406.4	1.10	27.9	14.25	362
18	457	1.60	40.6	15.75	400
20	508	1.80	45.7	17.9	454
24	610	1.87	47.5	21.5	546
26	660	1.87	47.5	23.5	597
30	762	2.20	55.9	27.08	687
34	864	2.20	55.9	31.1	790
48	1,219	2.50	63.5	44.4	1,127

NOTES

1 If dents and/or depressions occur in more than one quadrant, measure the pipe for minimum inside diameter (ID) using outside calipers and subtract twice the nominal wall thickness.

2 Includes all cases where internal pipe diameter is reduced from opposite two sides, i.e., buckling, ovality and ovality plus dents.

Crack-Like Indications

Crack-like indications are considered defects unless an Engineering Critical Assessment (ECA) determines that they are acceptable (see 06-03-24, Inspecting Crack-Like Indications).

Table 4 provides guidelines for repairing cracks.

Table 4
Crack-Like Indications Assessment and Repair

Location of Crack	Depth of Crack (through wall)	MOP During Repair	Repair Method
pipe body (includes cracks in corrosion[2], gouges or arc burns)	0 – 10%	MOP	grind; sleeve if required[1]
	10 – 40%	50% MOP	grind; sleeve if required[1]
	>40%[3]	250 psig max.[4]	grind up to 40%; install pressure-containment sleeve
circumferential fillet weld toe	0 – 10%	MOP	grind; sleeve if required[1]
	10 – 25%	50% MOP	grind; sleeve if required[1]
	25 – 40%	50% MOP	grind up to 40%; install pressure-containment sleeve
	>40%[3]	250 psig max.[4]	grind up to 40%; install pressure-containment sleeve
mill seam weld • SAW seam weld • ERW/FLASH welds	0 – 10%	MOP	grind; sleeve if required[1]
	10 – 40%	50% MOP	grind; sleeve if required[1]
	>40%[3]	250 psig max.[4]	grind up to 40%; install pressure-containment sleeve
circumferential butt weld (i.e., girth)	0 – 10%	MOP	grind; sleeve if required[1]
	10 – 40%	50% MOP	grind; sleeve if required[1]
	>40%[3]	250 psig max.[4]	grind up to 40%; install pressure-containment sleeve

NOTES

1 See 06-03-10, Grinding Repairs.
2 Total crack repair depth = depth of corrosion pit + depth of ground-out crack.
3 Through-wall pipe body and weld cracks do not require grinding but must be repaired with a pressure-containment sleeve or a Plidco® Split+Sleeve.
4 The Control Center must ensure there are no pressure surges during repair work.

Pipe body surface cracks are sometimes associated with gouges, grooves or arc burns. Surface cracks are considered defects and must be removed by grinding and then evaluated (see 06-03-10, Grinding Repairs). To examine the pipe body for surface cracks, use either color-contrast magnetic particle or wet fluorescent magnetic particle inspection (WFMPI) techniques.

Use a magnetic particle inspection technique to examine corrosion at the longitudinal seam welds for cracks at the weld toe, and to examine girth welds for cracks.

Where there is disbonded coating, general surface corrosion or pitting, use a magnetic particle inspection technique to examine 100% of the individual pits within a cluster for cracks.

Cracks may be found starting at the inside diameter (ID) surface of dents; therefore, examine dents using a shear wave ultrasonic technique over the entire area.

When cracks are found, determine the depths using a shear-wave ultrasonic technique.

Use a shear wave ultrasonic technique to identify the presence of midwall or internal surface indications such as lack of fusion, sloping laminations, or similar pipe wall indications.

CAN

Clusters of Crack-Like Indications

Evaluate clusters of crack-like indications to determine whether the cluster is significant (see 06-03-23, Evaluating Clusters of Crack-Like Indications). Crack clusters are significant when both of the following criteria are met:

- The total interacting length of the cracks within the cluster is greater than the length shown for the pipe in Table 5.
- The maximum depth of the interacting cracks is >10% of the wall thickness.

Report significant crack clusters immediately to Pipeline Integrity.

Table 5
Significant Stress Corrosion Cracking Length—CAN

Line Number	OD	Wt	Grade	Length of SCC
1	18	.281	X46	1.40
1	20	.312	X52	1.34
2	24	.281	X52	1.40
3	34	.281	X52	1.65
4	48	.406	X52	1.50
6B	30	.312	X52	1.64
6B	30	.500	X52	2.07
7	20	.312	X52	1.40
8	20	.312	X52	1.40
9	30	.250	X52	1.46
9	30	.281	X52	1.54
9	30	.312	X52	1.64
9	30	.375	X52	1.80
9	30	.500	X52	2.07
10	20	.250	X52	1.19
10	20	.500	X52	1.69
11	16	.250	X52	1.40
13	18	.281	X46	1.40
21	12	.270	X52	1.40

NOTES
All dimensions are in inches.

Enbridge Energy Company, Inc.
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Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

July 7, 2002

FAX (816) 734-9063

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

In accordance with Corrective Action Order CPF No. 3-2002-5017 Item 4, Enbridge seeks approval to re-fill the section of mainline pipe affected by the recent release of product at MP 1003. This action is required to facilitate the repair to the failed segment of pipe. The following is a detailed description of our proposed action plan:

A pre-tested joint of stock pipe has been prepared with two 2-inch TDW thread-o-ring fittings welded on at the 12 o'clock position. These 2-inch fittings with valves will be used to allow air to escape as product flows into the repair section. Hoses from these valves will be connected to a tanker truck to ensure no product is lost during the venting process. The replacement pipe will be attached to the existing mainline pipe via two weld+couplings utilized to facilitate alignment.

The existing pipe has had a portion of the coating removed and a visual inspection has been completed for internal and external corrosion. In addition, we have also completed ultrasonic inspection on the exposed longitudinal seam and pipe body in the weld area. The weld+couplings will then be tightened to manufacturer's specifications and in accordance with Enbridge O&MP Manual, Book 3.

Initially mainline valves downstream of the repair site will be opened one at a time. These are at MP 1007 and 1010. If the repair section is not flooded with this action, the Control Center will proceed to open all mainline valves, one at a time from Deer River Station to Clearbrook Station. During this process, the valve immediately downstream of Deer River Station will remain closed. When the station pressure transmitters have verified that the line pressure at Deer River Station is below 100 psig, the mainline valve downstream of the station will be opened. Communications will be maintained between personnel at the leak and valve sites at all times.

If the repair section does not flood as a result of this action, we will proceed to start a single booster pump at Clearbrook Station. The maximum discharge of the booster pump is 160 psig. All valves open prior to this will remain open while the booster pump is running.

That will result in a maximum pressure profile as follows:

Clearbrook - 160 psig
North Cass Lake - 164 psig
Deer River - 100 psig
MP 1002.7 (repair site) - 96 psig
MP 1017 - 96 psig

The pressure at the time of failure at MP 1002.7 has been calculated to be 525 psi. The MAOP of the line at MP 1002.7 is 687 psi.

Once we have verified that the repair section is flooded with crude oil, we will proceed with welding the weld+couplings to complete the installation of the replacement pipe. A third party certified welding inspector will monitor the welding process.

We believe that this procedure provides for the safest and most effective method of refilling the mainline section of pipe to facilitate repairs, as it keeps repressurization of the mainline pipe to a minimum. Your immediate review and approval of this procedure will be greatly appreciated.

Sincerely,

John R Sobojinski

c: John Hayes
Jay Johnson
Joel Kanvik
Greg Sevick
Mark Sitek
Dan Tutcher

****
*** TX REPORT ***
****

TRANSMISSION OK

TX/RX NO	1139
CONNECTION TEL	918163293831
SUBADDRESS	
CONNECTION ID	
ST. TIME	07/08 10:17
USAGE T	07'50
PGS.	24
RESULT	OK

Enbridge (U.S.), Inc.
Facsimile Transmission Cover Sheet

To: **Phil Archuletta**
(816) 329-3831

Subject: Request for Return to Service
Date: 07/08/2002 09:45:08 AM
Pages: 24, including cover page

From: Patsy M Bolk
Company: **Enbridge (U.S.) Inc.**
Address: Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067

Phone: (218) 725-0105
Fax: (218) 725-0109

DOT-RSPA-OPS
'02 JUL -9 10:26
CENTRAL REGION
KANSAS CITY MO

Message:
Attached is our request for a return to service for your review.

U.S. Department
of Transportation
**Research and
Special Programs
Administration**

400 Seventh St., S.W.
Washington, D.C. 20590

July 5, 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: CPF No. 3-2002-5017

Dear Mr. Tutcher:

Enclosed is a Corrective Action Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. Service is being made by certified mail and telecopy. Your receipt of the enclosed document constitutes service of that document under 49 C.F.R. § 190.5. The terms and conditions of this Corrective Action Order are effective upon receipt.

Sincerely,

for

Gwendolyn M. Hill
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

VIA CERTIFIED MAIL (RETURN RECEIPT REQUESTED) AND TELECOPY

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
WASHINGTON, DC 20590

In the Matter of Enbridge Energy Company, Inc. Respondent.	CPF No. 3-2002-5017

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112 , to require Enbridge Energy Company, Inc. (Enbridge), to take the necessary corrective action to protect the public and environment from potential hazards associated with its 34"-diameter Line 4 pipeline. The pipeline system originates in Gretna, Manitoba, Canada transporting crude oil south to Superior, Wisconsin. The Office of Pipeline Safety (OPS) has found that corrective action is necessary to determine the cause, and prevent possible recurrence, of the pipeline failure that occurred on July 4, 2002.

On July 4, 2002, at approximately 1:15 AM CDT, a release of approximately 3,000 to 6,000 barrels of crude oil occurred from the pipeline at milepost (MP) 1003.1, approximately ½ mile west of the city of Cohasset, Minnesota. The release was contained in an open marsh area.

Pursuant to 49 U.S.C. § 60117, the Central Region, OPS, initiated an investigation of this incident.

Preliminary Findings

- On July 4, 2002, at approximately 1:15AM CDT Enbridge's 34"-diameter Line 4 pipeline failed at MP 1003.1, approximately ½ mile west of the city of Cohasset, Minnesota, in Itasca County. The rupture location was downstream of the Deer River Pump Station (MP 995.83) in an open marsh area. The release was approximately 1/4 mile west of Pincherry Road, on the west side of Cohasset. The failure resulted in the release of approximately 3000 to 6000 barrels of crude oil.

- Indications of a pressure drop at 1:15 AM CDT on July 4, 2002 were noticed at Enbridge's Edmonton Control Center. The leak was confirmed at 6:57 AM CDT, and the NRC was notified at 6:59 AM CDT the same day.

- No injuries or fatalities occurred.

- To control the release, the Minnesota Pollution Control Agency initiated a controlled burn, which is ongoing as of the writing of this order.

- The pipeline is owned and operated by Enbridge and transports crude oil from Gretna, Manitoba, Canada, to Superior, Wisconsin.

- The Enbridge pipeline was installed in 1967 and traverses through the city of Superior, Wisconsin. The Superior Terminal is located at MP 1096.95. The pipeline crosses environmental areas.

- The release occurred on a 49 mile segment of the pipeline that runs from the Deer River Pump Station to the Floodwood Pump Station (1044.33). This segment is constructed with 0.312-inch wall thickness, API 5L-X52, double-submerged-arc-welded (DSAW) pipe manufactured by U.S. Steel.

- The Deer River to Floodwood segment has a maximum operating pressure (MOP) of 687 psig. The segment was last pressure tested in 1991.

- The operating pressure in effect at the time of the release at approximately 1:15 AM CDT on July 4, 2002, is unknown.

- The cause of the incident is currently unknown as the investigation is on-going and all facts have not yet been determined.

- The failed pipe has not yet been viewed by investigators as the site has not been deemed safe for investigative efforts.

- The pipeline was the subject of a hazardous facility order in 1991.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action as appropriate. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above referenced statute and 49 C.F.R. §190.233, a copy of which is enclosed.

Section 60112, and the regulations promulgated thereunder, provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that failure to issue the Order expeditiously will result in likely serious harm to life, property or the environment. In such cases, an opportunity or a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that the continued operation of this pipeline without corrective measures would be hazardous to life, property and the environment. Additionally, because of the location of the pipeline with respect to populated and environmental areas,and the uncertainties as to cause of the failure, I find that a failure to issue expeditiously this Order, requiring immediate corrective action, would result in likely serious harm to life, property, and the environment.

Accordingly, this Corrective Action Order mandating needed immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, the Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by telecopy (at (202) 366-4566). Any hearing will be held in Kansas City, Missouri, or Washington, D.C. on a date that is mutually convenient to OPS and the Respondent.

After receiving and analyzing additional data in the course of this investigation, OPS may identify other longer term measures that need to be taken. Respondent will be notified of any additional measures required and amendment of this Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Action

Pursuant to 49 U.S.C. § 60112, I hereby order Enbridge to immediately take the following corrective actions with respect to its 34"- diameter Line 4 pipeline.

With respect to the Deer River Pump Station to the Superior Terminal (MP 1096.95) segment:

1. Do not operate this segment until completing Items 3 and 4.

2. Conduct a detailed metallurgical analysis of the pipe that failed on July 4, 2002 to determine the cause and contributing factors. Submit to the Regional Director, Central Region, OPS, within one week of its receipt by Enbridge Energy Company, Inc.

3. Submit a return-to-service written plan, with a schedule, to verify the integrity of the line from the Deer River Pump Station to the Superior Terminal. The plan must provide integrity testing that addresses all known or suspected factors in the failure, including if relevant:

A. Internal inspection tool surveys and remedial action. The type of internal inspection tools used shall be technologically appropriate for assessing the system based on the type of failure that occurred on July 4, 2002, with emphasis on identifying and evaluating the following: 1) anomalies associated with dents, gouges and grooves; 2) metal loss due to corrosion; 3) the orientation of the longitudinal seam of the pipe; 4) pipe deformation, and 5) longitudinal cracks, mill defects and stress corrosion cracking.

B. A detailed description of the inspection and repair criteria that will be used in the field evaluation of the anomalies that are excavated. This is to include a description of how any defects are to be graded and the schedule for repairs or replacement.

C. An evaluation of the line for areas of damaged or disbonded coating, including but not limited to, a close-interval, current interrupted, pipe-to-soil potential survey.

D. Integration of all available data from internal inspections, metallurgical analyses, and historical data, including repair and cathodic protection records.

E. Hydrostatic pressure testing of line segment.

F. A schedule and means for providing the results and data for testing programs performed to the Central Region.

4. Each element of the plan must be approved by the Director, Central Region, OPS, who may provide approvals incrementally. Implement the plan as approved.

5. Submit the plan to Director, Central Region, Office of Pipeline Safety, Research and Special Programs Administration, 901 Locust Street, Suite 462, Kansas City, MO 64106-2641.

6. The Director, Central Region, OPS, may grant an extension of time for compliance with any of the terms of this order for good cause. A request for an extension must be in writing.

The procedures for the issuance of this Order are described in Part 190, Title 49, Code of Federal Regulations, § 190.233, a copy of which is enclosed, is made part of this Order and describe the Respondents' procedural rights relative to this Order.

Failure to comply with this Order may result in the assessment of civil penalties of not more than $25,000 per day and in referral to the Attorney General for appropriate relief in United States District

Court.

for Stacey Gerard
Associate Administrator
for Pipeline Safety

July 5, 2002
Date Issued

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Mar. 27, 1980, as amended by
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515, Apr. 26, 1996; 61 FR 38403,

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$10,000 must be made by wire transfer. Payments, or in the case of wire transfers, notices of payment, must be sent to the Chief, General Accounting Branch (M-86.2), Accounting Operations Division, Office of the Secretary, room 2228, Department of Transportation, 400 Seventh Street, SW, Washington, DC 20590.

(b) Payment of a civil penalty assessed in a final order issued under §190.213 or affirmed in a decision on a petition for reconsideration must be made within 20 days after receipt of the final order or decision. Failure to do so will result in the initiation of collection action, including the accrual of interest and penalties, in accordance with 31 U.S.C. 3717 and 49 CFR part 89.

[Amdt. 190-7, 61 FR 27792, June 3, 1996]

CRIMINAL PENALTIES

§190.229 Criminal penalties generally.

(a) Any person who willfully and knowingly violates a provision of 49 U.S.C. 60101 *et seq.* or any regulation or order issued thereunder shall upon conviction be subject for each offense to a fine of not more than $25,000 and imprisonment for not more than five years, or both.

(b) Any person who willfully violates a regulation or order under this subchapter issued under the authority of 49 U.S.C. 5101 *et seq.* as applied to offshore gas gathering lines shall upon conviction be subject for each offense to a fine of not more than $25,000, imprisonment for a term not to exceed 5 years, or both.

(c) Any person who willfully and knowingly injures or destroys, or attempts to injure or destroy, any interstate transmission facility or any interstate pipeline facility (as those terms are defined in 49 U.S.C. 60101 *et seq.*) shall, upon conviction, be subject for each offense to a fine of not more than $25,000, imprisonment for a term not to exceed 15 years, or both.

(d) Any person who willfully and knowingly defaces, damages, removes, destroys any pipeline sign, right-of-way marker, or marine buoy required by 49 U.S.C. 60101 *et seq.* or 49 U.S.C. 5101 *et seq.*, or any regulation or order issued thereunder shall, upon conviction, be subject for each offense to a fine of not more than $5,000, imprisonment for a term not to exceed 1 year, or both.

(e) No person shall be subject to criminal penalties under paragraph (a) of this section for violation of any regulation and the violation of any order issued under §190.217, §190.219 or §190.229 if both violations are based on the same act.

[45 FR 20413, Mar. 27, 1980, as amended by Amdt. 190-2, 54 FR 32344, Aug. 7, 1989; Amdt. 190-4, 56 FR 63770, Dec. 5, 1991; Amdt. 190-6, 61 FR 18515, Apr. 26, 1996]

§190.231 Referral for prosecution.

If an employee of the Research and Special Programs Administration becomes aware of any actual or possible activity subject to criminal penalties under §190.229, the employee reports it to the Office of the Chief Counsel, Research and Special Programs Administration, U.S. Department of Transportation, Washington, DC 20590. The Chief Counsel refers the report to OPS for investigation. Upon completion of the investigation and if appropriate, the Chief Counsel refers the report to the Department of Justice for criminal prosecution of the offender.

[Amdt. 190-6, 61 FR 18515, Apr. 26, 1996]

SPECIFIC RELIEF

§190.233 Hazardous facility orders.

(a) Except as provided by paragraph (b) of this section, if the Associate Administrator, OPS finds, after reasonable notice and opportunity for hearing in accord with paragraph (c) of this section, and §190.211(a), a particular pipeline facility to be hazardous to life or property, the Associate Administrator, OPS shall issue an order pursuant to this section requiring the owner or operator of the facility to take corrective action. Corrective action may include suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other action, as appropriate.

(b) The Associate Administrator, OPS may waive the requirement for notice and hearing under paragraph (a) of this section before issuing an order pursuant to this section when the Associate Administrator, OPS determines that the failure to do so would result in the likelihood of serious harm to life or property. However, the Associate Administrator, OPS shall include in the order an opportunity for hearing as soon as practicable after issuance of the order. The provisions of paragraph (c)(2) of this section apply to an owner or operator's decision to exercise such an opportunity for hearing. The purpose of such a post-order hearing is for the Associate Administrator, OPS to determine whether the order should remain in effect or be rescinded or suspended in accord with paragraph (g) of this section.

(c) Notice and hearing:

(1) Written notice that OPS intends to issue an order under this section shall be served in accordance with § 190.5, upon the owner or operator of an alleged hazardous facility. The notice shall allege the existence of a hazardous facility, stating the facts and circumstances supporting the issuance of a "hazardous facility order", and providing the owner or operator an opportunity for a hearing, identifying the time and location of the hearing.

(2) An owner or operator elects to exercise his opportunity for a hearing under this section, by notifying the Associate Administrator, OPS of that election in writing within 10 days of service of the notice provided under paragraph (c)(1) of this section or, under paragraph (b) of this section when applicable. Absence of such written notification waives an owner or operator's opportunity for a hearing and allows the Associate Administrator, OPS to proceed to issue a "hazardous facility order" in accordance with paragraphs (d) through (h) of this section.

(3) A hearing under this section shall be presided over by an attorney from the Office of Chief Counsel, Research and Special Programs Administration, acting as Presiding Official, and conducted without strict adherence to rules of evidence. The Presiding Official presents the allegations contained in the notice issued under this section. The owner or operator of the alleged hazardous facility may submit any relevant information or materials, call witnesses and present arguments on the issue of whether or not a "hazardous facility order" should be issued.

(4) Within 48 hours after conclusion of a hearing under this section, the Presiding Official shall submit a recommendation to the Associate Administrator, OPS as to whether or not a "hazardous facility order" is required. Upon receipt of the recommendation, the Associate Administrator, OPS shall proceed in accordance with paragraphs (d) through (h) of this section. If the Associate Administrator, OPS finds the facility to be hazardous to life or property the Associate Administrator, OPS shall issue an order in accordance with this section. If the Associate Administrator, OPS does not find the facility to be hazardous to life or property, the Associate Administrator, OPS shall dismiss the allegations contained in the notice, and promptly notify the owner or operator in writing by service as prescribed in § 190.5.

(d) The Associate Administrator, OPS may find a pipeline facility to be hazardous under paragraph (a) of this section:

(1) If under the facts and circumstances the Associate Administrator, OPS determines the particular facility is hazardous to life or property; or

(2) If the pipeline facility or a component thereof has been constructed or operated with any equipment, material, or technique which the Associate Administrator, OPS determines is hazardous to life or property, unless the operator involved demonstrates to the satisfaction of the Associate Administrator, OPS that, under the particular facts and circumstances involved, such equipment, material, or technique is not hazardous to life or property.

(e) In making a determination under paragraph (d) of this section, the Associate Administrator, OPS shall consider, if relevant:

(1) The characteristics of the pipe and other equipment used in the pipeline facility involved, including its age, manufacturer, physical properties (including its resistance to corrosion and deterioration), and the method of its manufacture, construction or assembly;

(2) The nature of the materials transported by such facility (including their corrosive and deteriorative qualities), the sequence in which such materials

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are transported, and the pressure required for such transportation;

(3) The aspects of the areas in which the pipeline facility is located, in particular the climatic and geologic conditions (including soil characteristics) associated with such areas, and the population density and population and growth patterns of such areas;

(4) Any recommendation of the National Transportation Safety Board issued in connection with any investigation conducted by the Board; and

(5) Such other factors as the Associate Administrator, OPS may consider appropriate.

(f) The order shall contain the following information:

(1) A finding that the pipeline facility is hazardous to life or property.

(2) The relevant facts which form the basis for that finding.

(3) The legal basis for the order.

(4) The nature and description of particular corrective action required of the respondent.

(5) The date by which the required action must be taken, or completed and, where appropriate, the duration of the order.

(6) If a hearing has been waived pursuant to paragraph (b) of this section, a statement that an opportunity for a hearing is provided at a particular location and at a certain time after issuance of the order.

(g) The Associate Administrator, OPS shall rescind or suspend a hazardous facility order whenever the Associate Administrator, OPS determines that the facility is no longer hazardous to life or property. When appropriate, however, such a rescission or suspension may be accompanied by a notice of probable violation issued under §190.207.

(h) At any time after an order issued under this section has become effective, the Associate Administrator, OPS may request the Attorney General to bring an action for appropriate relief in accordance with §190.235.

(i) Upon petition by the Attorney General, the District Courts of the United States shall have jurisdiction, to enforce orders issued under this section by appropriate means.

[45 FR 20413, Mar. 17, 1980, as amended by Amdt. 190-3, 56 FR 31090, July 9, 1991; Amdt. 190-6, 61 FR 18515, Apr. 26, 1996]

§190.235 Injunctive action.

Whenever it appears to the Associate Administrator, OPS that a person has engaged, is engaged, or is about to engage in any act or practice constituting a violation of any provision of 49 U.S.C. 60101 *et seq.* or any regulations issued thereunder, the Administrator, RSPA, or the person to whom the authority has been delegated, may request the Attorney General to bring an action in the appropriate U.S. District Court for such relief as is necessary or appropriate, including mandatory or prohibitive injunctive relief, interim equitable relief, and punitive damages as provided under 49 U.S.C. 60120 and 49 U.S.C. 5123.

[Amdt. 190-6, 61 FR 18516, Apr. 26, 1996]

190.237 Amendment of plans or procedures.

(a) A Regional Director begins a proceeding to determine whether an operator's plans or procedures required under parts 192, 193, 195, and 199 of this subchapter are inadequate to assure safe operation of a pipeline facility by issuing a notice of amendment. The notice shall provide an opportunity for a hearing under §190.211 of this part and shall specify the alleged inadequacies and the proposed action for revision of the plans or procedures. The notice shall allow the operator 30 days after receipt of the notice to submit written comments or request a hearing. After considering all material presented in writing or at the hearing, the Associate Administrator, OPS shall determine whether the plans or procedures are inadequate as alleged and order the required amendment if they are inadequate, or withdraw the notice if they are not. In determining the adequacy of an operator's plans or procedures, the Associate Administrator, OPS shall consider:

(1) Relevant available pipeline safety data;

(2) Whether the plans or procedures are appropriate for the particular type

U.S. Department of Transportation
Research and Special Programs Administration

400 Seventh Street, S.W.
Washington, D.C. 20590

JUL 11 2002

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

Re: CPF No. 3-2002-5017H

Dear Mr. Tutcher:

Enclosed is an amendment to the July 5, 2002, Corrective Action Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. The Amendment makes changes appropriate to the current status of the investigation into the Line 4 pipeline failure of July 4, 2002. These include the addition of information on the cause of the failure, the extension of the order to cover additional pipe, and some new requirements. Service is being made by certified mail and telecopy. Your receipt of the enclosed document constitutes service of that document under 49 C.F.R. § 190.5. The terms and conditions of this amendment are effective upon receipt.

Sincerely,

Gwendolyn M. Hill

Gwendolyn M. Hill
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

VIA CERTIFIED MAIL (RETURN RECEIPT REQUESTED) AND TELECOPY

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
WASHINGTON, DC 20590

In the Matter of Enbridge Energy Company, Inc. Respondent.

CPF No. 3-2002-5017H

AMENDMENT TO CORRECTIVE ACTION ORDER

Purpose and Background

On July 5, 2002, the Associate Administrator for Pipeline Safety issued a Corrective Action Order (Order) making preliminary findings of fact, and finding that the continued operation by Enbridge Energy Company, Inc. (Respondent), of the Deer River Pump Station to Superior Terminal segment of the 34"- diameter Line 4 pipeline would be hazardous to life, property, and the environment without the implementation of corrective measures. The Order required that corrective measures be taken prior to the return to service of the Deer River Pump Station to Superior Terminal segment. This Amendment supplements and revises certain information provided in the Order based upon information gained in the course of the investigation. It also adds additional specific requirements to the Order.

Addition and Correction of Information

- Bass Lake, Blackwater Creek, and the headwaters of the Mississippi River are all located within 2 miles of the failure location.

- The Order indicated that Respondent's pipeline system originates in Gretna, Manitoba, Canada. In actuality, Respondent's pipeline system originates elsewhere in Canada. The Gretna Pump Station pressurizes the pipeline to move crude oil into the United States.

- Respondent operates a 34"- diameter pipeline that it refers to as Line 3. Line 3 is located on approximately the same route as Line 4. Like Line 4, Line 3 has sections constructed with API 5L-X52, double-submerged-arc-welded (DSAW) pipe manufactured by U.S. Steel.

- The Order indicated that the failure location was milepost (MP) 1003.1. According to a letter dated July 7, 2002, to the Director, Central Region, OPS, from Respondent, the failure location was actually MP 1002.7.

- The Order indicated the operating pressure in effect at the time of the release on July 4, 2002, was unknown. According to Respondent's July 7, 2002, letter referenced above, the operating pressure of the pipeline at MP 1002.7 at the time of failure was 525 psi.

- When the Order was issued, the failure site had not been excavated. The failure site has now been excavated. The failure is characterized by an approximately 5' to 6' longitudinal split initiating near the toe of the longitudinal weld seam. The failure was located near the bottom of the pipe, at approximately the 5:30 o'clock position. The pipe is 34"-diameter, manufactured by U.S. Steel, with a DSAW seam. On July 7, 2002, the failed pipe section was removed from the pipeline and crated for shipment to the National Transportation Safety Board 's (NTSB's) laboratory in Washington, D.C., where metallurgical analysis will be performed.

- The 34"-diameter, DSAW U.S. Steel pipe in Line 3 is installed in pipeline sections upstream of Respondent's Clearbrook Pump Station (MP 909.1), which is near Clearbrook, Minnesota. The Clearbrook Pump Station is located northwest (upstream) of the Deer River Pump Station, which is near Dear River, Minnesota. The 34"-diameter, DSAW U.S. Steel pipe in Line 4 is installed in pipeline sections downstream of the Clearbrook Pump Station.

- Respondent's 34"-diameter, DSAW U.S. Steel pipe has a history of longitudinal seam failures. In 1991 a longitudinal seam failure involving this pipe occurred at MP 1009.9 in Grand Rapids, Minnesota, after which the Associate Administrator issued Enbridge (formerly known as Lakehead Pipe Line Company) a Hazardous Facility Order.

- Respondent's July 7, 2002, letter sought approval to conduct repairs on the section of mainline pipe associated with the failure using a procedure that required refilling the failed portion of pipeline with crude oil. By letter dated July 7, 2002, the Director, Central Region, OPS, approved the repair procedure.

- By letter dated July 8, 2002, Respondent sent the Director, Central Region, OPS, a return-to-service plan for the 34"-diameter portions of Line 4. The plan provided for restricted operating pressures which are substantially the same as what is set forth in the Amendments below. Respondent's plan also provided for similarly restricted operating pressures in its Line 3 34" U.S. Steel-manufactured pipe.

- The Director, Central Region, OPS, sent by telecopy (faxed) a letter to Respondent on July 8, 2002. The letter approved, incrementally per item 4 of the Order, those portions of the return-to-service plan addressing repair of the failed pipeline section at MP 1002.7 and return of Lines 3 and 4 to service at the reduced pressures provided in the plan. Other provisions of the plan remain under review and analysis pending the results of both the investigation into the failure and the metallurgical analysis of the failed pipe.

- On July 7, 2002, Respondent commenced installation of replacement pipe at the failure site. Respondent completed repair of the Line 4 MP 1002.7 failure site on July 8, 2002. At approximately 5:00 p.m. CDT on July 8, 2002, the 34"-diameter Line 4 resumed operation.

- NTSB completed its gathering of facts at Respondent's Control Center in Edmonton, Canada, on July 7, 2002. NTSB closed the on-site field portion of their investigation on July 9, 2002.

<u>Determination of Necessity for Amendment to Corrective Action Order and Right to Hearing</u>

Section 60112 of Title 49, United States Code, provides for the issuance of a corrective action order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action as appropriate. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above referenced statute and 49 C.F.R. §190.233, a copy of which is enclosed.

Section 60112, and the regulations promulgated thereunder, provide for the issuance of a corrective action order without prior opportunity for notice and hearing upon a finding that failure to issue the order expeditiously will likely result in serious harm to life, property or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the order.

Taking into consideration the facts alleged in the Order as well as the above factual amendments, I find that the continued operation of Line 3, to the extent it contains U.S. Steel-manufactured 34" DSAW pipe upstream of the Clearbrook Pump Station, and Line 4, to the extent it contains U.S. Steel-manufactured 34" DSAW pipe downstream of the Clearbrook Pump Station, without corrective measures would be hazardous to life, property and the environment. Because of the location of the pipeline with respect to populated and environmental areas, and the severity of the recent failure, I find that a failure to issue expeditiously this Amendment, requiring immediate corrective action, would likely result in serious harm to life, property, and the environment.

Accordingly, this Amendment mandating needed immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Amendment are effective upon receipt.

Within 10 days of receipt of this Amendment, the Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by telecopy (at (202) 366-4566). Any hearing will be held in Kansas City, Missouri, or Washington, DC, on a date that is mutually convenient to OPS and the Respondent.

After receiving and analyzing additional data in the course of this investigation, OPS may identify other, longer term measures that need to be taken. Respondent will be notified of any additional measures required and further amendment of the Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Discussion of Amendments

We now know that a 5' to 6' longitudinal seam split in the bottom of the Respondent's Line 4 pipeline at MP 1002.7 released between 3,000 and 6,000 barrels of crude oil on July 4, 2002. In 1991, a longitudinal seam split occurred at MP 1009.9.

The type of pipe that failed, 34"-diameter API 5L-X52 DSAW pipe manufactured by U.S. Steel, is in many sections along Respondent's Lines 3 and 4. Given the pipe's age, history, and the severity of the recent failure, safety requires that certain additional conditions be in place prior to the operation of Lines 3 and 4.

Operating Pressure

To provide for a margin of safety when there is a question of the integrity of pipe, OPS has consistently required that an operator reduce operating pressure by 20%. The Amendments contemplate an interim return-to-service plan, which allows Respondent to operate at the restricted pressure, and a plan for return to full service, both approved by the Director, Central Region, OPS.

Amendments

Pursuant to 49 U.S.C. § 60112, I hereby amend the Order and require Respondent to immediately take the following additional corrective actions with respect to its 34"-diameter DSAW pipe manufactured by U.S. Steel installed in Line 3 and in Line 4.

Modify the lead-in applicability language, **With respect to the Deer River Pump Station to the Superior Terminal (MP 1096.95) segment,** *to read as follows:*

With respect to Line 4, all pipeline sections containing 34"-diameter DSAW pipe manufactured by U.S. Steel and located between the Clearbrook Pump Station (MP 909.1) and the Superior Terminal (MP 1096.95); and

With respect to Line 3, all pipeline sections containing 34"-diameter DSAW pipe manufactured by U.S. Steel and located upstream of the Clearbrook Pump Station (MP 909.1), between the Clearbrook Pump Station (MP 909.1) and the U.S. - Canada border (MP 773.72):

Item 1 is amended to read as follows:

1. Do not operate these sections except as approved by the Director, Central Region, OPS: as necessary to effect repairs to the failure location; or under a return-to-service plan pursuant to item 3.

Item 3 is amended to read as follows:

3. Submit a return-to-service written plan, with a schedule, to verify the integrity of Line 4 from the Clearbrook Pump Station to the Superior Terminal, and also to verify the integrity of Line 3 from the U.S.- Canada border to the Clearbrook Pump Station.

* * * *

The following new sections are added to the Order:

7. Following approval of an interim return-to-service plan under item 3, the following pressure restrictions apply:

   A. The pressure at the failure location (Line 4, MP 1002.7) is not to exceed 80% of the pressure at the location at the time of failure.

   B. The pressures at all other locations covered by this Order are not to exceed 80% of the operating pressures at the time of the failure at the pump stations upstream of the above-described 34"-diameter DSAW U.S. Steel pipe sections.

8. The pressure restrictions in item 7 are to remain in effect until:

   A. A written plan for return to full service under item 3 has been submitted to, and approved by, the Director, Central Region, OPS, and the remedial actions required by that plan to ensure the safe operation of the pipelines have been completed; or

   B. The Director, Central Region, OPS, gives his approval, in writing, to an increase in operating pressure. Respondent may request approval from the Director to increase its operating pressure above the interim maximum operating pressure under item 7, based on a showing that the hazard has been abated or that a higher pressure is justified based on an analysis showing that the pressure increase is safe considering all known defects, anomalies and operating parameters of the pipeline. The Director's determination will be based on the cause of failure and provision of evidence that mitigative actions taken by the operator provide for the safe operation of the pipeline.

9. Appeals to determinations of the Regional Director will be subject to the decision of the Associate Administrator for Pipeline Safety.

The terms of the July 5, 2002 Order, as modified by this Amendment, remain in effect.

Failure to comply with this Amendment may result in the assessment of civil penalties of not more than $25,000 per day and in referral to the Attorney General for appropriate relief in United States District Court.

Stacey Gerard
Associate Administrator
for Pipeline Safety

JUL 11 2002
Date Issued

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U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 20, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5003M

Dear Mr. Tutcher:

On June 4, 2002, representatives of the Central Region, Office of Pipeline Safety and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your Operator Qualification Plan at Duluth, MN.

As a result of a review of your Operator Qualification Plan, the requirements for which are set forth in Title 49, Code of Federal Regulations, Part 195, Sections §195.501, §195.503, §195.505, §195.507 and §195.509, the following inadequate procedures were noted:

1. **§195.505 Qualification Program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   a. **§195.505(a) Identify covered tasks;**

   Enbridge's covered task list did not incorporate the new Sub-part H requirements for corrosion control.

   b. **§195.505(b) Ensure through evaluation that individuals**

performing covered tasks are qualified;

The plan did not include the operator's requirements for the qualifications of contractors performing covered tasks.

c. §195.505(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

(1) The plan required all re-qualifications on a triennial basis. The plan was inadequate because some of the operator's covered tasks or procedures required a more frequent re-qualification interval, but the plan did not include provisions for this.

(2) The plan did not include provisions for the five year retention requirement for contractor records and for the retention of records for employees who leave employment of the operator.

As provided in 49 C.F.R. §190.237, this Notice of Amendment serves as your notification that this office considers your procedures inadequate. Under 49 C.F.R. § 190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or a request for a hearing within 30 days after receipt of this Notice. After reviewing the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 C.F.R. § 190.237. If you do not wish to contest this Notice of Amendment, please provide your revised procedures within 45 days of receipt of this notice.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

Enbridge Pipelines (Lakehead) L.L.C.
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John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

March 31, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2003-5003M

Enclosed please find the updated Enbridge US DOT Operator Qualification Plan in response to the above referenced Notice of Amendment.

Changes related to the requirements listed in your notice have been highlighted. In addition, a guide has been enclosed to reference the specific sections and page numbers of the requested changes.

Sincerely,

John R. Sobojinski

Enclosure
c: John Hayes
Greg Sevick
Dan Tutcher
Law

ENBRIDGE US
Revised Operator Qualification Plan
Changes in response to audit June 4, 2002

195.505(a) New reference numbers from sub-part H

Appendix A
Cathodic Protection, page 7

195.505(b) Contractor requirements

Plan
Operator Qualification Guidelines
- Use of Non-qualified Individuals, page 7

Contractor Qualification Guidelines
- Contractor Documentary Evidence of Qualification, page 8
- Third Party Vendor, page 8 & 9
- Contractor Documentation of Approved Qualification, page 9 & 10
- Work Site Documentation Requirements, page 10

195.505(g) More frequent qualification interval

Plan
Operator Qualification Guidelines
- Required Re-evaluation After Qualification, page 7

195.505(g) Five year retention for contractors & former employees

Plan
Contractor Qualification Guidelines
- Contractor Qualification Guidelines, page 8
- Contractor Documentation of Approved Qualification, page 10
- Recordkeeping for Enbridge US Employees, page 10

DOT Operator Qualification Plan

In compliance with

Subpart G in 49 CFR Part 195
Subpart N in 49 CFR Part 192

Enbridge Energy, Limited Partnership
Enbridge Pipelines (North Dakota) LLC
Enbridge Pipelines (Toledo) Inc.
Vector Pipeline L.P.

TABLE OF CONTENTS

INTRODUCTION

- This Operator Qualification Plan is designed to demonstrate compliance with governmental regulation by ensuring a qualified workforce and instituting procedures that aid in reducing the probability and consequence of incidents caused by human error.
  - Regular company policies and procedures remain in place.

- This Plan covers only the following pipeline companies/systems operated by U.S. Enbridge affiliates (hereafter Enbridge US).

  Enbridge Energy, Limited Partnership
  Enbridge Pipelines (North Dakota) LLC
  Enbridge Pipelines (Toledo) Inc.
  Vector Pipeline L.P.

- This Operator Qualification Plan includes <u>all</u> individuals who perform covered tasks while operating and/or maintaining pipeline facilities on behalf of Enbridge US and intends to verify the capability of these individuals to operate and maintain the pipeline.
  - This compliance plan was established April 27, 2001, is currently in effect and will continue to evolve as needed.
  - All individuals performing covered tasks after October 28, 2002 will be qualified or supervised by a qualified individual.

RESPONSIBILITIES

- Operator Qualification Steering Committee
  - Oversee Operator Qualification process.
  - Review and update Operator Qualification Plan.
  - Review and update covered task lists.
  - Communicate significant changes as needed, as well as annually.

- Manager
  - Ensure all necessary qualifications are completed.
  - Communicate and reinforce the company's obligation to perform evaluations in compliance with DOT.

- Evaluator/Supervisor
  - Observe and evaluate employee performance of covered tasks.
  - Document qualification information in database.
  - Monitor employee performance and provide training as necessary.
  - Ensure a qualified individual is assigned to any non-qualified worker performing covered tasks.
  - Ensure all employees new to their area are qualified to perform the appropriate covered tasks.

- Individual
  - Become fully qualified in appropriate covered tasks.
  - Oversee the performance of covered tasks by those not qualified upon request.

- Project Manager
  - Understand the Company Operator Qualification Plan.
  - Include a listing of applicable covered tasks in project specifications.
  - Ascertain the qualification of contract workers prior to awarding the contract/commencement of work.
  - Ensure that a qualified contract worker is present to oversee the performance of any covered task performed by any non-qualified contract personnel.

- Contractor
  - Understand and comply with the Enbridge US Operator Qualification Plan.
  - Ensure workers employed to perform covered tasks on the Enbridge US system are properly qualified or supervised by a qualified worker.
  - Provide documentation to the Enbridge US indicating required qualification information.

INITIAL IDENTIFICATION OF COVERED TASKS

- The Enbridge US Operator Qualification Steering Committee, composed of representatives from various Operations disciplines, completed the identification of covered tasks and the preparation of this Plan.

- Task outlines and procedures have been written using a combination of knowledge gathered from experienced employees, Company manuals, industry standards, regulatory requirements and manufacturer's recommendations.

- The Operator Qualification Process and Performance Based Training Manual contains complete job task outlines.

- Where Company task outlines had not yet been established, covered tasks were adapted from industry standard.

- Task outlines and procedures were reviewed and evaluated using the following four-part criteria:
  - Is performed as a requirement of 49 CFR Part 195 or 192
  - Is an operations or maintenance task
  - Is performed on a pipeline facility
  - Affects the operation or integrity of the pipeline

- Covered tasks, for the purpose of Operator Qualification, are those operations tasks meeting all four criteria.

- The Covered Task Chart in Appendix A lists the tasks to be included as covered tasks for Enbridge US.

ENBRIDGE US EVALUATION PROCESS

Evaluation

- The standard of acceptable performance for satisfactory qualification will be the Enbridge US Company procedures for that task found in PBT Job Task Outlines, Maximo Job Plans, site specific guidelines and/or manufacturers' instructions.

- Evaluation of an individual's ability to perform a covered task is primarily determined by an evaluator utilizing one of the following two methods:

  1) **Observation of task performance/simulation**
     Qualification activities will be incorporated into the daily operations of the work area as much as possible.

  2) **Verbal review of task procedures**
     In instances where it is not practical to observe task performance, due to time and distance limitations, the evaluator may ask the individual to perform a walkthrough and explanation of the task procedures.

- The Evaluator, as a part of evaluation, will conduct a discussion ensuring compliance with Subpart G Part 195 and/or Subpart N Part 192, regarding the individual's ability to recognize and react to abnormal operating conditions that may occur while performing the identified covered tasks.
  - Abnormal operating conditions may include any indication of a malfunction of a component or deviation from normal operations that may indicate a condition exceeding design limits or result in a hazard to persons, property or the environment.
  - Evaluators are supplied with structured questions/scenarios on each covered task around which they will conduct the discussion regarding abnormal operating conditions.
  - An initial list of Abnormal operating condition examples found in Appendix C are intended to assist the evaluator by providing examples of abnormal operating conditions relating to the individual covered task. The evaluator may create additional questions specific to the evaluation situation.

- The employee may:
  - Review procedures prior to qualification.
  - Request a different evaluator if there is reason to believe the original evaluator lacked objectivity during the evaluation.

Evaluator

- The supervisor is responsible for ensuring compliance with Subpart G in 49 CFR Part 195 and/or Subpart N in CFR Part 192 and will normally act as an evaluator in performing evaluations.

- In cases where it may be impractical for the supervisor to complete all the required evaluations, the supervisor may designate an evaluator, with job specific knowledge, to assist in the evaluation of individuals and tasks.

- To qualify as an evaluator, an Enbridge US employee must :
  - Demonstrate appropriate interpersonal skills.
  - Be endorsed by management.
  - Possess knowledge of the task.
  - Complete evaluator training session

- To fulfill evaluation duties, an evaluator must:
  - Assess the individual's understanding of and ability to perform a covered task based upon the performance standard of proper procedure.
  - Determine the individual's understanding of and ability to recognize and appropriately react to abnormal operating conditions.
  - Document the individual's ability to perform a covered task.

OPERATOR QUALIFICATION GUIDELINES

Enbridge US Employee Training Process

- The Performance Based Training (PBT) Process, where implemented, will continue to be used for documenting the learning of job specific tasks by employees new to their position.
  - PBT is a progressive learning process used by the Company since 1993 to train employees learning a new job.
  - Learning is documented at three levels of attainment, with Level 1 indicating satisfactory independent performance of the task.
  - Non-qualified individuals will be evaluated on covered tasks when they have attained a Progress Status of Level 1 as documented in the Performance Based Training Process.

[redacted]

- Non-qualified individuals may perform covered tasks when directed and observed by a qualified individual who will ensure immediate corrective action is taken when necessary.

- Qualified individuals overseeing non-qualified workers are responsible for the correct and safe performance of the covered task(s).

- [redacted]

- [redacted]

Required Re-evaluation After Qualification

- An individual whose performance of a covered task may have contributed to a DOT reportable accident as defined in Part 195 and/or Part 192 will be re-evaluated on that covered task.

- An individual who may no longer be qualified to perform a covered task will be re-evaluated on that covered task. Such re-evaluation might take place in circumstances where the individual has:
  - Displayed unsatisfactory performance
  - Acquired physical/mental limitations
  - Not performed the task for a prolonged period of time or
  - The task procedure has been significantly re-written.

- In the above situations where re-evaluation is required, the individual will be suspended from <u>independent</u> performance of the identified covered task(s) until successful re-evaluation takes place.

- After initial qualification, subsequent re-qualifications for all qualified individuals will be on a triennial basis [redacted]

Operator Qualification Process Review and Update

- Covered tasks will be reviewed, updated and communicated by the Operator Qualification Steering Committee as changes occur.

Such changes may include:
  - Installation of new equipment or technology requiring procedural change
  - Modification of a pipeline facility impacting a covered task
  - Regulatory change
  - Company policy or procedure change

- If there is major change to the task procedure requiring a new understanding of how the task is performed, individuals expected to perform the task will be re-evaluated as if it were a new task.

- The Operator Qualification Process will be reviewed and updated as necessary on a yearly basis.

CONTRACTOR QUALIFICATION GUIDELINES

- Contractors engaged to perform covered work after October 28, 2002 on facilities subject to this Plan must comply with the Enbridge US Operator Qualification Plan.

[redacted] Documentation of compliance must be provided to Enbridge US prior to commencing the covered work, kept current for the duration of the work [redacted]

- Contractors may satisfy qualification requirements by one of the following methods:
  - ~~Documentary evidence of contractor qualification of employees via~~ observation of performance, verbal review of task procedure or written test pursuant to applicable regulations.
  - Operator approved third-party vendor qualification.

- Contract workers may be qualified and documented by the same method stated herein for Enbridge US employees in special circumstances.

Contractor Documentary Evidence of Qualification

- [redacted].

Third-Party Vendor Qualification

- Third-party vendor qualification options may be considered upon presentation of valid programs.

[redacted]

[redacted]

Contractor Documentation of Approved Qualification

- Contractor documentation must be submitted for approval prior to the start of covered work that demonstrates qualification of their employees under Subpart G in 49 CFR Part 195 or Subpart N in 49 CFR Part 192. This will include an adequate description of:

  - Any of the following evaluation methods for **Covered Tasks** and **Abnormal Operating Conditions** including:
    - Observation of task performance/simulation
    - Verbal review of task procedure by the individual
    - Written test

  - The following identifying data:
    - The name(s) of qualified individual(s)
    - Each covered task specific to the work being performed
    - Dates of satisfactory completion of Task and Abnormal Operating Condition evaluation(s)

[redacted]

[redacted]

- [redacted]

[redacted]

RECORDKEEPING FOR ENBRIDGE US EMPLOYEES

- Qualification records will be maintained that include identification of the following:
  1) Name of qualified individual
  2) Covered tasks that the individual is qualified to perform
  3) Dates of qualification
  4) Qualification method
     - Description of evaluation
     - Description of Abnormal Operating Condition discussion

- Each evaluator will enter evaluation documentation into the Covered Task Evaluation Forms in the DOT Operator Qualification computer database within Lotus Notes.

- The completed Operator Qualification Evaluation Form specific to each job class will be printed. The signature page will be printed and signed by employee, evaluator and manager in recognition of satisfactory evaluation of identified covered tasks and attached to the back of the OQ Evaluation Form.

- [redacted].

APPENDIX

A. Covered Task Chart

B. Definitions

C. Abnormal Operating Condition Examples
- Industry General
- Pipeline Maintenance
- Electrical
- Mechanical
- Terminal/Delivery
- Cathodic Protection Inspection

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Pipeline Maintenance	**Part 195**	**Part 192**
Backfilling After Excavation	252	319b
Defect Investigation - External Corrosion - Internal Corrosion - Dent - Gouge	416e/418d	713/459
Pipeline Repair - Sleeving - Stopple Fitting Installation - Weld Plus - Plidco Split Repair Sleeve - Clockspring	422a	713/717
Tapping - 101 - 660 - 1200	422a	627
Plugging - 101 - 660 - 1200	422a	—
Plug Removal - 101 - 660 - 1200	422a	—
Launching Tool in Scraper Trap	426	—
Receiving Tool in Scraper Trap	426	—
Shorted Casing Clearing	[redacted]	467d
Test Lead Installation (Cadweld)	[redacted]	471
Hydrostatic Testing of Pipe	300	503
Line Lowering	424	—
Pipe & Valve Coating	[redacted]	461
Welding	214	227
Line Crossing	442b	614
Line Markers	410	707a

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Pipeline Maintenance	**Part 195**	**Part 192**
Site Security	436	613

Patrol Pilot	**Part 195**	**Part 192**
Right of Way Inspection	412a	705/613

Electrical	**Part 195**	**Part 192**
Rectifier Inspection	[redacted]	465b
Coupon Inspection	[redacted]	—
PLC/RTU Pressure Allowable Set Points	406b	—
Remote Communicated Valve Check	408a/420b	745
Station Gas Detector Calibration	402c11	736
PCV Maintenance	428/420a	—
Thermal Pressure Relief Valve Test	428a	—
Pressure Switch Calibration	428a	—
Pressure Transmitter Calibration	428a	—
Valve Operator Maintenance	408/420	—
Launching Tool in Scraper Trap	426	—
Receiving Tool in Scraper Trap	426	—
Site Security	436	613

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Mechanical	Part 195	Part 192
Unit/Booster Repair/Replacement	422a	---
M/L DOT Valve Inspection	420b	745
In Service Valve Repair (Operator, stem & valve body) - M/L - PCV - Unit - Manifold - Check	420a	---
Thermal Pressure Relief Valve Test	428a	---
M/L Pressure Relief Valve Test	428a	---
Corrosion Inhibitor Injection	[redacted]	---
Launching Tool in Scraper Trap	426	---
Receiving Tool in Scraper Trap	426	---
Site Security	436	613

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Terminal/Delivery	**Part 195**	**Part 192**
Terminal Computer Operation	408b	---
Computer Gauging	408a	---
Pressure Monitoring/Chart - Holding - Mainline - Station suction - Manifold -	408b1	605b5
Line Start Up	402c7	605b5
Line Shut Down	402c7	605b5
Oil Movement - Delivery - Injection - Receipt -	402c7	605b5
Tank Gauging/Inspection	432/428	—
Launching Tool in Scraper Trap	426	—
Receiving Tool in Scraper Trap	426	—
Site Security	436	613

Technical Systems Support	**Part 195**	**Part 192**
PLC Implementation & Testing	406b	—
HMI Implementation & Testing	406b	—

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Cathodic Protection	Part 195	Part 192
Annual DOT Survey - Pipe to Soil - Casing to Soil	[redacted]	465a
Coupon Inspection	[redacted]	—
Critical Bond Inspection - Interference Testing	[redacted]	465c 473a
External Coating Inspection	[redacted]	461/465a
Groundbed Installation	[redacted]	455
Rectifier Inspection ~~(Reverse current switch)~~ - Installation - Maintenance	[redacted]	465b
Shorted Casing Inspection – Voltage/Resistance - Pipe to Soil - Casing to Soil - Casing to Pipe	[redacted]	467d
Test Lead Installation (Cadweld)	[redacted]	471

Gas Technical	Part 195	Part 192
Start Gas Compressor Unit	—	605b7
Stop Gas Compressor Unit	—	605b7
Compressor Unit Maintenance	—	605b6/731
Purge Gas Facilities (unit, station piping or pipeline) - Purge Air - Purge Gas	—	629
Gas Leakage Survey	—	706
Overpressure Protection, Relief & Regulator Device Maintenance	—	731a/739
Remote Control Shutdown Device Maintenance	—	731c
Site Security	436	613

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

ND Gauger/Utility/Operator	**Part 195**	**Part 192**
Site Security	436	613
Pressure Monitoring/Chart	408b1	605b5
Launching Tool in Scraper Trap	426	605
Receiving Tool in Scraper Trap	426	605
Line Crossing	442b	614
Line Markers	410	707a
Oil Movement - Delivery Completion	402c7	605b5
Tank Gauging/Inspection	432/428	—
Rectifier Inspection	[redacted]	465b
M/L DOT Valve Inspection	420b	745

CONTRACT TASKS

Non-Operational Control	**Part 195**	**Part 192**
Non-destructive Testing	234	243
Navigable Water Crossing Inspection	412b	613
In Service Tank Inspection (API 653)	432	—
Hydrostatic Testing Existing Pipe	300	501

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

CONTRACT TASKS

Pipeline & Terminal Operations	Part 195	Part 192
Pipeline Start-up	402c	605b5
Pipeline Shut Down	402c7	605b5
Oil Delivery - Full Stream Delivery - Side-Stream Delivery - Simultaneous with Injection - Tank to Tank Transfer	402c7	—
Gas Delivery to Interconnect	—	605b5
Oil Injection - Full Stream Injection - Side-Stream Injection - Simultaneous with Delivery	402c7	—
Gas – Interconnect - Receipt - Delivery	—	605b5
Compressor Operation	—	605b6
Monitoring Pressures & Flows	402c7	605b5
Remote Valve Operation	402c/406 /408b1	605b5
Station Bypass	402e4	—
Steady State Operations	402c/406	—
Leak Detection Monitoring (CPM)	444	—
Monitor Tank Levels	402c7	—
Tankage/Shipper - Delivery - Injection - Tank Transfer	402c7	—
Emergency Shut Down	402e4	615a6

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 20, 2003

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5004

Dear Mr. Tutcher:

On June 17-21, 2002, August 19-23, 2002 and October 22, 2002, representatives of the Central Region, Office of Pipeline Safety, and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your records at Minot, ND and your field facilities located within the states of Minnesota and North Dakota for Enbridge Pipelines (North Dakota), Inc.

As a result of the inspection, it appears that you have committed probable violations, as noted below, of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1) **§ 195.404 - Maps and records.**

§ 195.404(c)(3) requires each operator to maintain a record of each inspection and test required by this subpart for at least 2 years or until the next inspection or test is performed, whichever is longer.

a) Maximum operating pressure of the Minot to Pleasant Lake segment is incorrectly listed as 944. The correct maximum operating pressure is 936, based upon 80% of the hydrostatic test pressure of 1170 psig (1170 x 0.8 = 936).

b) Enbridge's "Safety Device Testing and Inspection" forms were incomplete in that dates when inspections were conducted and initials of the person performing the inspections were missing in numerous places on the inspection forms.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations we will take enforcement action when and if the continued violations come to our attention.

In addition to this, the inspection revealed several areas of concern that we would like to bring to your attention. They are as follows:

1. Enbridge's pre-tested marked pipe, located at Enbridge's Minot, ND Station, could not be directly tied to the pressure test records retained for the pre-tested pipe.

2. MPM 94 (Minot to Grand Forks segment) - The pipe wrap was deteriorated along the topside at the downstream pipe to soil interface.

3. MPM 83 (Lignite to Berthold segment) - At the Lignite location, the pipe wrap was deteriorated at the downstream pipe to soil interface.

4. MPM 52 (Lignite to Berthold segment) - At the Kenaston Block Valve, the paint coating on the pipe was deteriorated. This facility is scheduled for painting this year.

5. MPM 129 (Grenora to Beaver Lodge segment) - At the Grenora Station, the paint coating on the bottom of the receiver barrel from the Reserve Station was deteriorated.

6. Alexander Station - In the manifold piping area, one pipe support was not in contact with the pipe.

7. MPM 51 (Beaver Lodge to Berthold segment) - At the Stanley Station, the pipe wrap was deteriorated at the pipe to soil interface on the line from Tank #9002.

These items were discussed with your representatives during the inspection. They indicated that the items would receive attention.

The Central Region, Office of Pipeline Safety, has received documents from Enbridge Pipelines (North Dakota) giving evidence that corrective actions for items 3 and 4 above have been completed. The documents have been reviewed by the Office of Pipeline Safety and are acceptable. No additional actions are required on field issues items 3 and 4. The Office of Pipeline Safety appreciates your attention in this matter and good faith efforts to promote continued safety in your organization.

If we can be of any assistance, please contact me or my staff at (816) 329-3800. Thank you for your staff's cooperation during this scheduled inspection.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. Mark Kinbloom
Manager
Enbridge Pipelines (North Dakota) Inc.
2625 Railway Ave.
Minot, ND 58703-5002

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Compl Req
Stewart-Cover Ltr.

Enbridge Pipelines (Lakehead) L.L.C.
Lake Superior Place
21 West Superior Street
Duluth, MN 55802-2067
www.enbridgepartners.com

John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 218 725 0505
Fax 218 725 0149
john.sobojinski@enbridge-us.com

ENBRIDGE™

March 31, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2003-5003M

Enclosed please find the updated Enbridge US DOT Operator Qualification Plan in response to the above referenced Notice of Amendment.

Changes related to the requirements listed in your notice have been highlighted. In addition, a guide has been enclosed to reference the specific sections and page numbers of the requested changes.

Sincerely,

John R. Sobojinski

Enclosure
c: John Hayes
Greg Sevick
Dan Tutcher
Law

ENBRIDGE US
Revised Operator Qualification Plan
Changes in response to audit June 4, 2002

195.505(a) New reference numbers from sub-part H

Appendix A
Cathodic Protection, page 7

195.505(b) Contractor requirements

Plan
Operator Qualification Guidelines
- Use of Non-qualified Individuals, page 7

Contractor Qualification Guidelines
- Contractor Documentary Evidence of Qualification, page 8
- Third Party Vendor, page 8 & 9
- Contractor Documentation of Approved Qualification, page 9 & 10
- Work Site Documentation Requirements, page 10

195.505(g) More frequent qualification interval

Plan
Operator Qualification Guidelines
- Required Re-evaluation After Qualification, page 7

195.505(g) Five year retention for contractors & former employees

Plan
Contractor Qualification Guidelines
- Contractor Qualification Guidelines, page 8
- Contractor Documentation of Approved Qualification, page 10
- Recordkeeping for Enbridge US Employees, page 10

DOT Operator Qualification Plan

In compliance with

Subpart G in 49 CFR Part 195
Subpart N in 49 CFR Part 192

Enbridge Energy, Limited Partnership
Enbridge Pipelines (North Dakota) LLC
Enbridge Pipelines (Toledo) Inc.
Vector Pipeline L.P.

TABLE OF CONTENTS

INTRODUCTION

- This Operator Qualification Plan is designed to demonstrate compliance with governmental regulation by ensuring a qualified workforce and instituting procedures that aid in reducing the probability and consequence of incidents caused by human error.
  - Regular company policies and procedures remain in place.

- This Plan covers only the following pipeline companies/systems operated by U.S. Enbridge affiliates (hereafter Enbridge US).

  Enbridge Energy, Limited Partnership
  Enbridge Pipelines (North Dakota) LLC
  Enbridge Pipelines (Toledo) Inc.
  Vector Pipeline L.P.

- This Operator Qualification Plan includes <u>all</u> individuals who perform covered tasks while operating and/or maintaining pipeline facilities on behalf of Enbridge US and intends to verify the capability of these individuals to operate and maintain the pipeline.
  - This compliance plan was established April 27, 2001, is currently in effect and will continue to evolve as needed.
  - All individuals performing covered tasks after October 28, 2002 will be qualified or supervised by a qualified individual.

RESPONSIBILITIES

- Operator Qualification Steering Committee
  - Oversee Operator Qualification process.
  - Review and update Operator Qualification Plan.
  - Review and update covered task lists.
  - Communicate significant changes as needed, as well as annually.

- Manager
  - Ensure all necessary qualifications are completed.
  - Communicate and reinforce the company's obligation to perform evaluations in compliance with DOT.

- Evaluator/Supervisor
  - Observe and evaluate employee performance of covered tasks.
  - Document qualification information in database.
  - Monitor employee performance and provide training as necessary.
  - Ensure a qualified individual is assigned to any non-qualified worker performing covered tasks.
  - Ensure all employees new to their area are qualified to perform the appropriate covered tasks.

- Individual
  - Become fully qualified in appropriate covered tasks.
  - Oversee the performance of covered tasks by those not qualified upon request.

- Project Manager
  - Understand the Company Operator Qualification Plan.
  - Include a listing of applicable covered tasks in project specifications.
  - Ascertain the qualification of contract workers prior to awarding the contract/commencement of work.
  - Ensure that a qualified contract worker is present to oversee the performance of any covered task performed by any non-qualified contract personnel.

- Contractor
  - Understand and comply with the Enbridge US Operator Qualification Plan.
  - Ensure workers employed to perform covered tasks on the Enbridge US system are properly qualified or supervised by a qualified worker.
  - Provide documentation to the Enbridge US indicating required qualification information.

INITIAL IDENTIFICATION OF COVERED TASKS

- The Enbridge US Operator Qualification Steering Committee, composed of representatives from various Operations disciplines, completed the identification of covered tasks and the preparation of this Plan.

- Task outlines and procedures have been written using a combination of knowledge gathered from experienced employees, Company manuals, industry standards, regulatory requirements and manufacturer's recommendations.

- The Operator Qualification Process and Performance Based Training Manual contains complete job task outlines.

- Where Company task outlines had not yet been established, covered tasks were adapted from industry standard.

- Task outlines and procedures were reviewed and evaluated using the following four-part criteria:
  - Is performed as a requirement of 49 CFR Part 195 or 192
  - Is an operations or maintenance task
  - Is performed on a pipeline facility
  - Affects the operation or integrity of the pipeline

- Covered tasks, for the purpose of Operator Qualification, are those operations tasks meeting all four criteria.
- The Covered Task Chart in Appendix A lists the tasks to be included as covered tasks for Enbridge US.

ENBRIDGE US EVALUATION PROCESS

Evaluation

- The standard of acceptable performance for satisfactory qualification will be the Enbridge US Company procedures for that task found in PBT Job Task Outlines, Maximo Job Plans, site specific guidelines and/or manufacturers' instructions.
- Evaluation of an individual's ability to perform a covered task is primarily determined by an evaluator utilizing one of the following two methods:

    1) **Observation of task performance/simulation**
    Qualification activities will be incorporated into the daily operations of the work area as much as possible.

    2) **Verbal review of task procedures**
    In instances where it is not practical to observe task performance, due to time and distance limitations, the evaluator may ask the individual to perform a walkthrough and explanation of the task procedures.

- The Evaluator, as a part of evaluation, will conduct a discussion ensuring compliance with Subpart G Part 195 and/or Subpart N Part 192, regarding the individual's ability to recognize and react to abnormal operating conditions that may occur while performing the identified covered tasks.
    - Abnormal operating conditions may include any indication of a malfunction of a component or deviation from normal operations that may indicate a condition exceeding design limits or result in a hazard to persons, property or the environment.
    - Evaluators are supplied with structured questions/scenarios on each covered task around which they will conduct the discussion regarding abnormal operating conditions.
    - An initial list of Abnormal operating condition examples found in Appendix C are intended to assist the evaluator by providing examples of abnormal operating conditions relating to the individual covered task. The evaluator may create additional questions specific to the evaluation situation.

- The employee may:
    - Review procedures prior to qualification.
    - Request a different evaluator if there is reason to believe the original evaluator lacked objectivity during the evaluation.

Evaluator

- The supervisor is responsible for ensuring compliance with Subpart G in 49 CFR Part 195 and/or Subpart N in CFR Part 192 and will normally act as an evaluator in performing evaluations.

- In cases where it may be impractical for the supervisor to complete all the required evaluations, the supervisor may designate an evaluator, with job specific knowledge, to assist in the evaluation of individuals and tasks.

- To qualify as an evaluator, an Enbridge US employee must :
  - Demonstrate appropriate interpersonal skills.
  - Be endorsed by management.
  - Possess knowledge of the task.
  - Complete evaluator training session

- To fulfill evaluation duties, an evaluator must:
  - Assess the individual's understanding of and ability to perform a covered task based upon the performance standard of proper procedure.
  - Determine the individual's understanding of and ability to recognize and appropriately react to abnormal operating conditions.
  - Document the individual's ability to perform a covered task.

OPERATOR QUALIFICATION GUIDELINES

Enbridge US Employee Training Process

- The Performance Based Training (PBT) Process, where implemented, will continue to be used for documenting the learning of job specific tasks by employees new to their position.
  - PBT is a progressive learning process used by the Company since 1993 to train employees learning a new job.
  - Learning is documented at three levels of attainment, with Level 1 indicating satisfactory independent performance of the task.
  - Non-qualified individuals will be evaluated on covered tasks when they have attained a Progress Status of Level 1 as documented in the Performance Based Training Process.

Use of Non-qualified Individuals

- Non-qualified individuals may perform covered tasks when directed and observed by a qualified individual who will ensure immediate corrective action is taken when necessary.

- Qualified individuals overseeing non-qualified workers are responsible for the correct and safe performance of the covered task(s).

- Non-qualified workers may be used with the ratio not to exceed two non-qualified workers to one qualified worker with a preference for one non-qualified to one qualified worker for the purpose of allowing time for the training and qualifying of the non-qualified worker.

- Non-qualified workers may perform a covered task up to ten times while being directed and observed by a qualified worker after which they must be operator qualified.

Required Re-evaluation After Qualification

- An individual whose performance of a covered task may have contributed to a DOT reportable accident as defined in Part 195 and/or Part 192 will be re-evaluated on that covered task.

- An individual who may no longer be qualified to perform a covered task will be re-evaluated on that covered task. Such re-evaluation might take place in circumstances where the individual has:
  - Displayed unsatisfactory performance
  - Acquired physical/mental limitations
  - Not performed the task for a prolonged period of time
    or
  - The task procedure has been significantly re-written.

- In the above situations where re-evaluation is required, the individual will be suspended from <u>independent</u> performance of the identified covered task(s) until successful re-evaluation takes place.

- After initial qualification, subsequent re-qualifications for all qualified individuals will be on a triennial basis unless the specific procedure indicates a more frequent interval (e.g. Company welding requirements)

Operator Qualification Process Review and Update

- Covered tasks will be reviewed, updated and communicated by the Operator Qualification Steering Committee as changes occur.

Such changes may include:
  - Installation of new equipment or technology requiring procedural change
  - Modification of a pipeline facility impacting a covered task
  - Regulatory change
  - Company policy or procedure change

- If there is major change to the task procedure requiring a new understanding of how the task is performed, individuals expected to perform the task will be re-evaluated as if it were a new task.

- The Operator Qualification Process will be reviewed and updated as necessary on a yearly basis.

CONTRACTOR QUALIFICATION GUIDELINES

- Contractors engaged to perform covered work after October 28, 2002 on facilities subject to this Plan must comply with the Enbridge US Operator Qualification Plan.

- Documentation of compliance must be provided to Enbridge US prior to commencing the covered work, kept current for the duration of the work and be retained for five years.

- Contractors may satisfy qualification requirements by one of the following methods:
  - Documentary evidence of contractor qualification of employees via observation of performance, verbal review of task procedure or written test pursuant to applicable regulations.
  - Operator approved third-party vendor qualification.

- Contract workers may be qualified and documented by the same method stated herein for Enbridge US employees in special circumstances.

Contractor Documentary Evidence of Qualification

- Companies who contract to supply 24 hour pipeline, gas and terminal operation control services for Enbridge US must provide on line access to a current database containing qualification data for their operators.

Third-Party Vendor Qualification

- Third-party vendor qualification options may be considered upon presentation of valid programs.

- Enbridge US recognizes two third party operator qualification vendors.
  - National Center for Construction, Education and Research (NCCER)
    - Enbridge US accepts any one of the following NCCER qualifications.
      - Performance Verification
      - Training Module with Performance Verification & Written Test
      - Written Assessment Test including AOC Assessment
    - Enbridge US has requested that contractors certify their own evaluators/instructors through an NCCER Accredited Sponsor to enable them to conduct Performance Verifications and deliver Training Modules to their own employees.

- Enbridge Technology
  - Contractors using Enbridge Technology Operator Qualification material must complete and provide documentation including all of the following parts of each specific Covered Task Training Module.
    - Skill Checklist
    - AOC Scenario
    - Final Exam
  - Evaluators, with proper expertise, may be selected by the Contractor to deliver the Training Module and testing.

Contractor Documentation of Approved Qualification

- Contractor documentation must be submitted for approval prior to the start of covered work that demonstrates qualification of their employees under Subpart G in 49 CFR Part 195 or Subpart N in 49 CFR Part 192. This will include an adequate description of:

  - Any of the following evaluation methods for **Covered Tasks** and **Abnormal Operating Conditions** including:
    - Observation of task performance/simulation
    - Verbal review of task procedure by the individual
    - Written test

  - The following identifying data:
    - The name(s) of qualified individual(s)
    - Each covered task specific to the work being performed
    - Dates of satisfactory completion of Task and Abnormal Operating Condition evaluation(s)

- Enbridge US will use ISNetworld Internet Compliance Records Management as the preferred documentation source to identify qualified workers prior to the beginning of work and for the duration of any work that includes covered tasks.
  - Contractors, subscribing to ISNetworld, who propose to provide services to Enbridge US, must grant access to their qualification data by submitting an OQ Report on ISNetworld updated as personnel changes throughout the job.

- Contractors not subscribing to ISNetworld will be required to show documentation of qualification prior to the commencement of work by submitting to Enbridge US by any one of the following:
  - NCCER completed Performance Verification Form
  - NCCER Official Transcript
  - NCCER completed Training Report Form (Form 200)
  - Enbridge Technology covered task module Skill Checklist, AOC Scenario and Final Exam

- Contractor qualification records will be retained within the ISNetworld system and/or by Enbridge US for five years.

Work Site Documentation Requirements

- Contractors must provide the names and the qualification status of all individuals they intend to assign to Enbridge jobs that include covered tasks at least 24 hours prior to the start of work.
- Enbridge personnel will verify the qualifications of the proposed workers via proper documentation and send a list of names to the Enbridge representative at the job site.
- Qualified worker picture I.D.'s will be checked prior to the start of work at the job site to confirm the identity of qualified individuals.
- A representative of Enbridge and a contractor representative will complete the Contractor Operator Qualification Report listing the name and qualification status of each worker.
- Completed Contractor Operator Qualification Reports are scanned and sent in computer file with PLM Reporting or kept in the Project File.

RECORDKEEPING FOR ENBRIDGE US EMPLOYEES

- Qualification records will be maintained that include identification of the following:
  1) Name of qualified individual
  2) Covered tasks that the individual is qualified to perform
  3) Dates of qualification
  4) Qualification method
     - Description of evaluation
     - Description of Abnormal Operating Condition discussion

- Each evaluator will enter evaluation documentation into the Covered Task Evaluation Forms in the DOT Operator Qualification computer database within Lotus Notes.

- The completed Operator Qualification Evaluation Form specific to each job class will be printed. The signature page will be printed and signed by employee, evaluator and manager in recognition of satisfactory evaluation of identified covered tasks and attached to the back of the OQ Evaluation Form.

- All records of qualification of current and former employees will be retained in hard copy as well as computer documentation in their respective region office for five years.

APPENDIX

A. Covered Task Chart

B. Definitions

C. Abnormal Operating Condition Examples
- Industry General
- Pipeline Maintenance
- Electrical
- Mechanical
- Terminal/Delivery
- Cathodic Protection Inspection

Appendix A

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Pipeline Maintenance	**Part 195**	**Part 192**
Backfilling After Excavation	252	319b
Defect Investigation - External Corrosion - Internal Corrosion - Dent - Gouge	416e/418d	713/459
Pipeline Repair - Sleeving - Stopple Fitting Installation - Weld Plus - Plidco Split Repair Sleeve - Clockspring	422a	713/717
Tapping - 101 - 660 - 1200	422a	627
Plugging - 101 - 660 - 1200	422a	---
Plug Removal - 101 - 660 - 1200	422a	---
Launching Tool in Scraper Trap	426	---
Receiving Tool in Scraper Trap	426	---
Shorted Casing Clearing	575	467d
Test Lead Installation (Cadweld)	567b	471
Hydrostatic Testing of Pipe	300	503
Line Lowering	424	---
Pipe & Valve Coating	569	461
Welding	214	227
Line Crossing	442b	614
Line Markers	410	707a

Appendix A

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Pipeline Maintenance	Part 195	Part 192
Site Security	436	613

Patrol Pilot	Part 195	Part 192
Right of Way Inspection	412a	705/613

Electrical	Part 195	Part 192
Rectifier Inspection	573c	465b
Coupon Inspection	579b	---
PLC/RTU Pressure Allowable Set Points	406b	---
Remote Communicated Valve Check	408a/420b	745
Station Gas Detector Calibration	402c11	736
PCV Maintenance	428/420a	---
Thermal Pressure Relief Valve Test	428a	---
Pressure Switch Calibration	428a	---
Pressure Transmitter Calibration	428a	---
Valve Operator Maintenance	408/420	---
Launching Tool in Scraper Trap	426	---
Receiving Tool in Scraper Trap	426	---
Site Security	436	613

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Mechanical	Part 195	Part 192
Unit/Booster Repair/Replacement	422a	---
M/L DOT Valve Inspection	420b	745
In Service Valve Repair (Operator, stem & valve body) - M/L - PCV - Unit - Manifold - Check	420a	---
Thermal Pressure Relief Valve Test	428a	---
M/L Pressure Relief Valve Test	428a	---
Corrosion Inhibitor Injection	579b	---
Launching Tool in Scraper Trap	426	---
Receiving Tool in Scraper Trap	426	---
Site Security	436	613

Appendix A

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Terminal/Delivery	Part 195	Part 192
Terminal Computer Operation	408b	---
Computer Gauging	408a	---
Pressure Monitoring/Chart - Holding - Mainline - Station suction - Manifold -	408b1	605b5
Line Start Up	402c7	605b5
Line Shut Down	402c7	605b5
Oil Movement - Delivery - Injection - Receipt -	402c7	605b5
Tank Gauging/Inspection	432/428	---
Launching Tool in Scraper Trap	426	---
Receiving Tool in Scraper Trap	426	---
Site Security	436	613

Technical Systems Support	Part 195	Part 192
PLC Implementation & Testing	406b	---
HMI Implementation & Testing	406b	---

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

Cathodic Protection	Part 195	Part 192
Annual DOT Survey - Pipe to Soil - Casing to Soil	573a/571	465a
Coupon Inspection	579b	---
Critical Bond Inspection - Interference Testing	575/577	465c 473a
External Coating Inspection	569/573a	461/465a
Groundbed Installation	567c/571	455
Rectifier Inspection (Reverse current switch) - Installation - Maintenance	573c	465b
Shorted Casing Inspection – Voltage/Resistance - Pipe to Soil - Casing to Soil - Casing to Pipe	575/567c	467d
Test Lead Installation (Cadweld)	567b	471

Gas Technical	Part 195	Part 192
Start Gas Compressor Unit	---	605b7
Stop Gas Compressor Unit	---	605b7
Compressor Unit Maintenance	---	605b6/731
Purge Gas Facilities (unit, station piping or pipeline) - Purge Air - Purge Gas	---	629
Gas Leakage Survey	---	706
Overpressure Protection, Relief & Regulator Device Maintenance	---	731a/739
Remote Control Shutdown Device Maintenance	---	731c
Site Security	436	613

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

ND Gauger/Utility/Operator	Part 195	Part 192
Site Security	436	613
Pressure Monitoring/Chart	408b1	605b5
Launching Tool in Scraper Trap	426	605
Receiving Tool in Scraper Trap	426	605
Line Crossing	442b	614
Line Markers	410	707a
Oil Movement - Delivery Completion	402c7	605b5
Tank Gauging/Inspection	432/428	---
Rectifier Inspection	573c	465b
M/L DOT Valve Inspection	420b	745

CONTRACT TASKS

Non-Operational Control	Part 195	Part 192
Non-destructive Testing	234	243
Navigable Water Crossing Inspection	412b	613
In Service Tank Inspection (API 653)	432	—
Hydrostatic Testing Existing Pipe	300	501

COVERED TASKS
OPERATOR QUALIFICATION
Part 195 & 192

CONTRACT TASKS

Pipeline & Terminal Operations	Part 195	Part 192
Pipeline Start-up	402c	605b5
Pipeline Shut Down	402c7	605b5
Oil Delivery - Full Stream Delivery - Side-Stream Delivery - Simultaneous with Injection - Tank to Tank Transfer	402c7	---
Gas Delivery to Interconnect	---	605b5
Oil Injection - Full Stream Injection - Side-Stream Injection - Simultaneous with Delivery	402c7	---
Gas – Interconnect - Receipt - Delivery	---	605b5
Compressor Operation	---	605b6
Monitoring Pressures & Flows	402c7	605b5
Remote Valve Operation	402c/406 /408b1	605b5
Station Bypass	402e4	---
Steady State Operations	402c/406	---
Leak Detection Monitoring (CPM)	444	---
Monitor Tank Levels	402c7	---
Tankage/Shipper - Delivery - Injection - Tank Transfer	402c7	---
Emergency Shut Down	402e4	615a6

(4)

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 23, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5003M

Dear Mr. Tutcher:

As a result of an inspection of your Operator Qualification Plan on June 4, 2002, by representatives of the Central Region, Office of Pipeline Safety (OPS) and the Minnesota Office of Pipeline Safety (MNOPS), at Enbridge's Duluth, MN office, a Notice of Amendment was issued on February 20, 2003. This Notice required amendment of certain procedures contained within Enbridge's Operator Qualification Plan. We received correspondence and copies of amended pages of Enbridge's Operator Qualification Plan, submitted by Enbridge by letter dated March 31, 2003. The revised procedures have been reviewed and found to be acceptable.

This letter is to inform you that no further action is necessary and that this case is being closed. Thank you for your cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc Mr. Mark J. Willoughby
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
119 North 25th Street East
Superior, WI 54880

Mr. Charles Kenow, Administrator
Minnesota Office of Pipeline Safety
444 Cedar Street
Suite 147-N, Town Square
St. Paul, Minnesota 55101-5147

Mr. Boyd Haugrose
Minnesota Office of Pipeline Safety
31332 County Hwy 34
Ogema, MN 56569

Mr. Brian Pierzina
Minnesota Office of Pipeline Safety
607 NW 5th Street, Suite 103
Grand Rapids, MN 55744

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 20, 2003

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5004

Dear Mr. Tutcher:

On June 17-21, 2002, August 19-23, 2002 and October 22, 2002, representatives of the Central Region, Office of Pipeline Safety, and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your records at Minot, ND and your field facilities located within the states of Minnesota and North Dakota for Enbridge Pipelines (North Dakota), Inc.

As a result of the inspection, it appears that you have committed probable violations, as noted below, of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1) **§ 195.404 - Maps and records.**

§ 195.404(c)(3) requires each operator to maintain a record of each inspection and test required by this subpart for at least 2 years or until the next inspection or test is performed, whichever is longer.

a) Maximum operating pressure of the Minot to Pleasant Lake segment is incorrectly listed as 944. The correct maximum operating pressure is 936, based upon 80% of the hydrostatic test pressure of 1170 psig (1170 x 0.8 = 936).

b) Enbridge's "Safety Device Testing and Inspection" forms were incomplete in that dates when inspections were conducted and initials of the person performing the inspections were missing in numerous places on the inspection forms.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations we will take enforcement action when and if the continued violations come to our attention.

In addition to this, the inspection revealed several areas of concern that we would like to bring to your attention. They are as follows:

1. Enbridge's pre-tested marked pipe, located at Enbridge's Minot, ND Station, could not be directly tied to the pressure test records retained for the pre-tested pipe.

2. MPM 94 (Minot to Grand Forks segment) - The pipe wrap was deteriorated along the topside at the downstream pipe to soil interface.

3. MPM 83 (Lignite to Berthold segment) - At the Lignite location, the pipe wrap was deteriorated at the downstream pipe to soil interface.

4. MPM 52 (Lignite to Berthold segment) - At the Kenaston Block Valve, the paint coating on the pipe was deteriorated. This facility is scheduled for painting this year.

5. MPM 129 (Grenora to Beaver Lodge segment) - At the Grenora Station, the paint coating on the bottom of the receiver barrel from the Reserve Station was deteriorated.

6. Alexander Station - In the manifold piping area, one pipe support was not in contact with the pipe.

7. MPM 51 (Beaver Lodge to Berthold segment) - At the Stanley Station, the pipe wrap was deteriorated at the pipe to soil interface on the line from Tank #9002.

These items were discussed with your representatives during the inspection. They indicated that the items would receive attention.

The Central Region, Office of Pipeline Safety, has received documents from Enbridge Pipelines (North Dakota) giving evidence that corrective actions for items 3 and 4 above have been completed. The documents have been reviewed by the Office of Pipeline Safety and are acceptable. No additional actions are required on field issues items 3 and 4. The Office of Pipeline Safety appreciates your attention in this matter and good faith efforts to promote continued safety in your organization.

If we can be of any assistance, please contact me or my staff at (816) 329-3800. Thank you for your staff's cooperation during this scheduled inspection.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. Mark Kinbloom
Manager
Enbridge Pipelines (North Dakota) Inc.
2625 Railway Ave.
Minot, ND 58703-5002

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 25, 2003

Mr. Dan C. Tutcher
President
Enbridge (US), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5006M

Dear Mr. Tutcher:

On June 17-21, 2002, representatives of the Central Region, Office of Pipeline Safety, and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your manuals at Minot, ND in conjunction with a system type inspection of Enbridge Pipelines (North Dakota) facilities.

As a result of a review of your operating and maintenance manual, the requirements for which are set forth in Section 195.402, specifically under 195.402(c)(6), (c)(13), (e)(1), (e)(2), and 195.402(c)(3), which requires procedures for operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of Subpart F and Subpart H, the following inadequate procedures were noted:

1. **§195.214 Welding: General.**

   §195.214(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

Enbridge's procedure did not make a direct reference to the 18th Edition of API Standard 1104 to clarify which edition is to be used.

2. **§195.222 Welders: Qualification of welders.**

Each welder must be qualified in accordance with Section 3 of API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not requalify under that earlier edition.

Enbridge's procedure did not make a direct reference to the 18th Edition of API Standard 1104 to clarify which edition is to be used.

3. **§195.228 Welds and welding inspection: Standards of acceptability.**

§195.228(b) The acceptability of a weld is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be determined under that appendix.

Enbridge's procedure did not make a direct reference to the 18th Edition of API Standard 1104 to clarify which edition is to be used.

4. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

§195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

§195.402(c)(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

Enbridge's procedure did not provide clear direction concerning minimizing the potential for hazards and minimizing the possibility of recurrence of accidents.

§195.402(e) Emergencies. **The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs;**

§195.402(e)(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

Enbridge's procedure did not provide clear direction concerning classifying all notices of events or call-ins of events.

§195.402(e)(2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.

Enbridge's procedure did not provide clear direction concerning making a prompt response to a notice of emergency resulting from a natural disaster.

5. **§195.410 Line markers.**

§195.410(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

§195.410(a)(2) The marker must state at least the following: "Warning" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline" (in lettering at least 1 inch high with an approximate stroke of one-quarter inch on a background of sharply contrasting color), the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

Enbridge's procedure did not provide clear direction concerning the letter size and stroke size for markers.

6. **§195.422 Pipeline repairs.**

§195.422(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

Enbridge's procedure did not provide clear direction that specific components may not be used for replacement or repair unless the components were designed and constructed as required by Part 195.

7. **§195.428 Overpressure safety devices.**

§195.428(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

Enbridge's procedure did not provide clear direction concerning inspection of relief valves and the inspection interval required.

8. **§195.432 Breakout tanks.**

§195.432(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).

Enbridge's procedure did not provide clear direction concerning conducting tank inspections in accordance with API Standard 653.

§195.432(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last

recorded date of the inspection, whichever is earlier.

Enbridge's procedure did not provide clear direction concerning the required time intervals for tank inspections.

9. **§195.442 Damage Prevention Program**

§195.442(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

§195.442(c)(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

> **(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and**
> **(ii) In the case of blasting, any inspection must include leakage surveys.**

Enbridge's procedure did not provide clear direction concerning conducting a leakage survey after any blasting activities near pipeline facilities.

10. **§195.559 What coating material may I use for external corrosion control?**

Coating material for external corrosion control under Sec. 195.557 must--

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;
(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
(c) Be sufficiently ductile to resist cracking;
(d) Have enough strength to resist damage due to handling and soil stress;
(e) Support any supplemental cathodic protection; and
(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

Enbridge's procedure did not provide clear direction concerning the criteria and characteristics for coating materials.

11. **§195.561 When must I inspect pipe coating used for external corrosion control?**
(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.
(b) You must repair any coating damage discovered.

Enbridge's procedure did not provide clear direction concerning inspecting coatings and repairing damaged coating.

12. **§195.563 Which pipelines must have cathodic protection?**

§195.563(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

Enbridge's procedure did not provide clear direction concerning providing cathodic protection within 1 year.

§195.563(c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection. Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003

Enbridge's procedure did not provide clear direction concerning protecting buried or submerged pipelines with a cathodic protection system.

§195.563(d) Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.

Enbridge's procedure did not provide clear direction concerning the specific areas that must have cathodic protection.

13. **§195.573 What must I do to monitor external corrosion control?**

§195.573(a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

§195.573(a)(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

Enbridge's procedure did not provide clear direction concerning identifying criteria for when a close-interval survey or a comparable technology is necessary.

§195.573(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	**Check frequency**
Rectifier........................ Reverse current switch Diode Interference bond whose failure would jeopardize structural protection	**At least six times each calendar year, but with intervals not exceeding 2 ½ months**
Other interference bond	**At least once each calendar year, but with intervals not exceeding 15 months.**

Enbridge's procedure did not include all of the devices listed in the regulation that must be electrically checked.

14. **§195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**

(a) You must electrically isolate each buried or

submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.
(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.
(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.
(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

Enbridge's procedure did not provide clear direction concerning which facilities must have electrical isolation and what inspections and tests must be conducted.

15. **§195.577 What must I do to alleviate interference currents?**

(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.
(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

Enbridge's procedure did not provide clear direction concerning minimizing the effects of stray currents and designing/installing cathodic protection systems to minimize the effect on existing metallic structures.

16. **§195.583 What must I do to monitor atmospheric corrosion control?**

§195.583(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

Enbridge's procedure did not provide clear direction concerning the frequency of inspections for atmospheric corrosion.

As provided in 49 C.F.R. §190.237, this Notice of Amendment serves as your notification that this office considers your procedures inadequate. Under 49 C.F.R. § 190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or a request for a hearing within 30 days after receipt of this Notice. After reviewing the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 C.F.R. § 190.237. If you do not wish to contest this Notice of Amendment, please provide your revised procedures within 30 days of receipt of this notice.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. Mark Kinbloom
Manager
Enbridge Pipelines (North Dakota) Inc.
2625 Railway Ave.
Minot, ND 58703-5002

Enbridge Pipelines (North Dakota) LLC
2625 Railway Avenue
Minot, North Dakota 58703-5002
Telephone: (701) 857-0800
Fax: [701] 857=0809
www.enbridge.com

ENBRIDGE

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

March 26, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, KS 64106-2641

RE: CPF No. 3-2003-5006M

Dear Mr. Huntoon:

In regards to your letter dated February 25, 2003, Notice of Amendment, the following revisions have been made to the manual:

- #1 Section 3.10 – Page 2
- #2 Section 3.10 – Page 4
- #3 Section 3.10 – Page 9
- #4 Section 1.2 – Pages 1 and 2; Section 4.15 – Page 3
- #5 Section 3.3 – Page 2
- #6 Section 3.9 – Pages 10 and 11
- #7 Section 3.6 – Pages 3 and 4
- #8 Section 3.8 – Pages 1,2,3,12 and 13
- #9 Section 4.15 – Page 6
- #10 Section 3.7 – Page 14
- #11 Section 3.9 – Page 11
- #12 Section 3.7 – Page 2
- #13 Section 3.7 – Pages 4,5,6 and 7
- #14 Section 3.7 – Pages 4,5,6 and 7
- #15 Section 3.7 – Pages 4,5,6 and 7
- #16 Section 3.7 – Page 14

If you have any questions please contact Dennis Anderson at (701)857-0845.

Sincerely,

Brian Johnson
Manager

Enc.

cc: Dennis Anderson
Kevin Hatfield
Phil Archuletta

ENBRIDGE PIPELINES (NORTH DAKOTA) LLC
EMERGENCY RESPONSE PLAN

SECTION 1.0

Issued: 03/14/03-R

1.2 REPORTING REQUIREMENTS

CONTENTS

EXHIBITS

A. INTRODUCTION

1. Major oil, product and chemical spills have generated complex technical, legal and public relations problems for the companies involved. Prior planning can help avoid or minimize such difficulties.

2. It cannot be emphasized too strongly that the best way to handle spills is to prevent their occurrences by every possible means. This can be achieved through planning, good housekeeping, and adequate equipment, along with proper maintenance and operation of that equipment.

3. However, in spite of the best care, accidental spills may occur and the handling of spills may require the immediate coordination of efforts of various company personnel and, perhaps, cooperatives, outside contractors and/or government agencies.

4. The guidelines presented in the following pages are designed to help Enbridge Pipelines (North Dakota) LLC deal with accidental oil spills and/or natural disasters affecting the pipeline. The objective is to prevent as far as practicable, any injury to persons or damage to property, wildlife or the ecology from such incidents.

5. Within these guidelines are generalized descriptions of the duties that must be implemented when an incident occurs. The guidelines plus the detailed action plans provide personnel with procedures for handling these incidents effectively.

6. Some of the procedures are essential, and they are properly identified. Others are merely suggested, and their application may be varied, depending upon the conditions of the incident.

7. The section on technical information pertaining to cleanup methods is subject to modification as technology improves. Additions and revisions will be provided as they become known and should be added to the response plan to keep it up to date.

B. <u>REPORTING REQUIREMENTS</u>

1. This emergency response plan becomes effective immediately upon observance of an oil spill from a company installation of any kind, which could possibly affect municipal water supplies, livestock, aquatic or other life in inland waters, or which could involve other properties, shorelines or beaches. Exhibit 1.2-1 provides an overview of emergency action procedures. Exhibit 1.2-2 provides telephone numbers for emergency response personnel Supervisors at Minot, Grand Forks and Williston are equipped with cell phones and pagers for 24-hour duty call.

2. Leaks and/or any type of emergency (flood, tornado, fire, explosion or any other natural disaster affecting the pipeline) reported by aerial patrol, landowners along the right-of-way, or others shall be immediately investigated by the Area Supervisor or his designee.

3. The responsibility for the notification of an oil spill rests with any company employee observing an oil spill of any quantity. The employee must immediately notify the Control Centre at 1-306-636-7222 (if no response call 1-888-838-4545) of the spill. The control centre in Estevan is manned 24 hours a day. The employee then notifies the appropriate supervisor who in turn notifies the manager (Qualified Individual). If the employee is unable to reach the Area Supervisor, he/she will then contact the manager. Notification of company response personnel will be by telephone or company (800) pager.

   According to 49 CFR 195.50, an accident report (Form 7000-1) (Exhibit 1.2-3) is required for each failure in a pipeline system in which there is a release of hazardous liquid resulting in any of the following:

   a. Explosion or fire not intentionally set by operator;

   b. Release of 5 gallons or more of hazardous liquid, except that no report is required for a release of less than 5 barrels resulting from pipeline maintenance activity if the release is:

      i. Not otherwise reportable under this section;
      ii. Not one described in 195.52 (a) (4) (water pollution);
      iii. Confined to company property or pipeline right-of-way; and
      iv. Cleaned up promptly;

   c. Death of any person;

   d. Personal injury necessitating hospitalization;

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1. Type and Placement

Markers consist of posts and pipeline warning signs installed to indicate the presence of a buried pipeline. The markers shall be installed about two (2) feet from the pipeline centerline to prevent damage to the pipe or its coating.

2. Posts

Posts may be made of steel, aluminum, reinforced concrete, wood, or other materials which will insure adequate strength, stiffness, and durability. Protection against below-ground corrosion or weathering shall be provided as necessary. Vent pipe, aerial patrol markers, or milepost markers may be used as posts for installing pipeline warning signs.

3. Pipeline Warning Signs

a. Signs shall be made of strong, durable material and finished to resist the effects of exposure and vandalism. Pipeline warning signs must state at least the following: "Warning" followed by the words "Petroleum Pipeline" (or the name of the hazardous liquid transported) in lettering at least 1 inch high with an approximate stroke of ¼" on a background of sharply contrasting color.

b. Signs must contain the name of the operator and a 24-hour emergency telephone number (including area code). An example of the sign used by the Company is shown in Exhibit 3.3-1.

C. LOCATIONS FOR PIPELINE MARKERS

1. Highway And Railroad Crossings And Along Pipeline Route

a. Pipeline markers shall be located on each side of each public road crossing and railroad crossing in sufficient numbers along the remainder of each buried pipeline so that its location is accurately known.

b. Signs shall be sufficiently elevated above grade to allow them to be clearly viewed from a distance and to remain visible above normal vegetation or snow accumulations.

c. Markers shall normally be placed at locations where they will not interfere with normal right-of-way maintenance or use of the land by its owners. Markers may be placed at fence lines, property lines, right-of-way boundaries,

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Additional safety devices include:

a. Low suction pressure.

b. Temperature sensors.

c. Vibration sensors.

d. Seal tank level sensors.

2. At the required DOT inspection interval, not exceeding 15 months but at least once each calendar year, the protective shutdown switches shall be checked to see that they are functioning properly. The information to be completed on the inspection report form (Exhibit 3.6-1) will be station name, device location, tag I.D., device type, manufacturers serial number, type service, set values (alarm or shutdown), test values and whether received by SCADA. The status of the safety device will be noted, initials of tester and date tested are also required. In the event adjustments are needed they should be noted along with any Trouble Report numbers for repairs made. When repairs are made date and initials of the repairer will be entered on the inspection report.

3. A certified dead weight tester or master gauge together with a pressure source shall be connected to the instrument piping leading to individual switches. The pressure at which the switches trip shall be recorded. If a switch is not consistent, proves troublesome, or does not retain continuity, it shall be replaced.

4. At the same time a shutdown switch is tested, transmitters, recorders, and input to controllers shall be checked. The certified dead weight tester or master gauge and the manufacturer's recommended test equipment shall be used for this check. The Bourdon pressure gauges on the piping shall also be checked. Recalibrations of the equipment shall be made as required.

E. RELIEF VALVES

1. Pressure relief valves are placed within the manifold piping to prevent a build up of pressure should a line section become isolated due to closing of valves. The relief valves within the manifold area are generally designed to relieve excess pressure from thermal expansion due to ambient conditions or heat generated by any other outside source such as a centrifugal pump which is unable to move a sufficient volume. This type of relief valve does not necessarily release a large volume.

A larger relief valve designed to allow for greater flow is used on the discharge of a positive displacement pump such as a gaso. These relief valves are sized to the output of the pump itself and are installed in the pump discharge between the pump and the first valve that can be closed on the discharge piping. Unlike the relief valves installed for thermal relief which open to the station sump, the relief valve on the PD pump allows the crude oil to re-circulate back through its suction. If allowed to continue over a period to time it will generate heat in the crude oil and the pump, and possible packing failure.

2. Relief valves should not be used as a means to maintain operations within set pressure limits.

3. At the required DOT inspection interval, not exceeding 15 months but at least once each calendar year, each relief valve shall be checked to see that it is functioning properly. The pertinent information shall be completed on the Safety Device Testing and Inspection Report (Exhibit 3.6-1) for each valve. Information to be noted would be pressure at which the valve operates as well as any changes made along with any Trouble Report numbers covering any repairs made or required. Dates and initials of tester shall also be recorded.

4. A certified dead weight tester or master gauge together with a pressure source shall be used to activate the relief valve for the test.

5. Indications of a relief valve operating is not directly indicated to the PLC and the operator. Other factors observed by the operator will make them aware of a problem that must be checked out by local personnel.

F. INSPECTION REPORT FORM

1. On completion of this testing, the inspection report form (Exhibit 3.6-1) shall be completed. The test results shall be noted for each switch and the amount of deviation from set pressure shall be noted. The reset pressures shall be listed. Any pertinent observations on operating condition of any switches shall be noted under the "Remarks" section of the inspection report form.

2. Repairs, replacements, or maintenance on any of the overpressure safety devices shall be noted on the inspection report form along with any Trouble Report numbers required. Any change to a device setting shall be documented as to who approved (appropriate supervisor) and reason for change when it substantially alters alarm level.

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5. Clean, coat, and maintain each component in its pipeline system exposed to atmosphere with material suitable for prevention of atmospheric corrosion.

6. Whenever any buried pipe is exposed for any reason, examine pipe for evidence of external corrosion. If general pitting or other evidence of active corrosion is found or if corrosion has caused a leak further investigations shall be conducted to determine extent of the corrosion.

7. When transporting any commodity that is corrosive to its facilities, take steps to mitigate the corrosion. If corrosion inhibitors are used it shall be in sufficient quantity to protect intended part of system. Then coupons or other monitoring equipment shall be used to determine their effectiveness. At intervals not exceeding 7 1/2) months, but at least twice each calendar year, examine such coupons or monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.

8. Whenever any pipe is removed from the pipeline for any reason, inspect its internal surface and adjacent pipe for evidence of corrosion and extent of the corrosion.

9. For generally corroded pipe where the remaining wall thickness is less than the minimum required by the specification tolerances, repair or replace pipe as necessary with coated pipe that meets requirements of this part, or reduce the maximum operating pressure to limits commensurate with the actual remaining wall thickness.

10. Localized corrosion pitting requires pipe replacement or reduced operating pressure to limits commensurate with the actual remaining wall thickness.

11. Maintain for the useful life of the pipeline, records of each inspection, investigation, or test required herein.

B. <u>CATHODIC PROTECTION SURVEY</u>

Enbridge Pipelines (ND) system does not contain any bare pipe. All buried or submerged pipelines in the Enbridge (ND) system, including breakout tanks and pump stations, are protected by a cathodic protection system. Cathodic protection must be in operation not later than one (1) year after a pipeline is constructed, relocated, replaced, or otherwise changed.

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b. Measurements shall be taken at each test station to compare against the criteria of 4.b, below.

c. Design and installation of cathodic protection ground beds shall be completed by qualified corrosion control personnel. Design of the ground bed size, placement and type shall be taken into consideration to reduce or eliminate adverse effects on foreign facilities. Typical placement of the ground bed should be remote from and normally not be within a minimum of 100 feet of any foreign facility.

d. Interference Investigation

i. As part of initial survey or when a new structure is installed across or near the pipeline system, a joint investigation with a representative of the foreign facility shall be made whenever there is a reasonable possibility of damage to or from the foreign structure. The objective is to resolve the interference problem, if any, to the mutual satisfaction of both parties.

ii. A record of the investigation shall be made to show before and after conditions on both structures and what, if any, corrective measures were taken. This record in narrative form shall be kept in the Minot Office for the operating life of the structure.

iii. Tests should be repeated when changes in applied current are made by either system that could possibly affect the previous situation.

iv. During the annual cathodic protection survey, interference testing shall be conducted to determine if either detrimental interference effects may be present. This procedure shall involve the simultaneous interruption of all rectifiers on the Enbridge system and the recording of pipe to soil potential readings on both the Enbridge facilities and the foreign facilities. If a significant detrimental interference problem is discovered it should be reported to the foreign operator and mutual corrective action taken. This may involve installation of magnesium anodes as a preferred return path for the current on the foreign line, installation of a controlled interference bond, adjustment of rectifiers in the area, or other action. If an interference bond is installed, it shall be monitored on the same schedule as the rectifier maintenance program.

4. Criteria for Cathodic Protection and Determination of Measurements

No one criterion for evaluating the effectiveness of cathodic protection has proven to be satisfactory for all conditions. Often a combination of criteria is needed for a single facility. The following criteria can be used to effectively evaluate that an adequate level of protection is achieved.

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a. A negative (cathodic) voltage of at least 0.85 volt with reference to a saturated copper - copper sulfate half-cell. Determination of this voltage must be made with the protective current applied.

   i. Voltage (IR) drops other than those across the structure - electrolyte boundary must be considered for valid interpolation.

b. A minimum negative (cathodic) polarization voltage shift of 100 mill volts. On most structures the 100 milli volt shift will occur within 24 hours. If all of the shift has not occurred within 24 hours monitoring shall continue until the 100 milli volt shift has taken place or at least for 72 hours at which time all data shall be evaluated to determine if additional measures are required. This polarization voltage shift must be determined in accordance with B. 4. (a.i.), of this section.

c. The process to ensure bond integrity for foreign line crossing is:

   i. Foreign line soil to pipe potential (a minimum of 850 mv)
   ii. Current across bond shunt
   iii. Bond diode
   iv. Enbridge's line soil to pipe potentials with the bond connection opened (A slight change should be observed.)

NOTE: A deviation from normal and acceptable readings should be investigated and resolved.

d. Areas on the pipeline where, low instant off potentials are noted or areas with high current requirements, which may indicate possible coating damage or lack of adequate protection, should be considered for implementation of a close interval potential survey. This survey would typically be conducted with all rectifiers simultaneously interrupted.

e. All underground or submerged pipelines shall be isolated from foreign pipelines, casings, or any other foreign metallic structures. All connections to foreign lines, casings or structures shall be made through bond wires brought above ground into a suitable enclosure. Provisions shall be made to allow the disconnection or isolation of this connection for testing purposes.

f. The pipeline system has several isolation kits installed at mainline valves sites, launcher and receiver sites as well as on lateral lines tied into mainlines and at all tie-ins to foreign facilities. The purpose of these isolation kits is to facilitate the testing and control of the cathodic protection current. All isolation kits other than the tie-in points to foreign facilities operate with a bond wire across the isolation kit, effectively shorting it. Opening of this bond would not be a normal operating condition. Isolation kits at foreign tie-in points are to be effectively isolated at all times.

g. The isolation kits are tested during the annual cathodic protection survey. At that time, all rectifiers on the Enbridge system are simultaneously interrupted. Pipe to soil potential measurements are obtained on either side of the isolation kits, using a common half-cell position. Using this procedure, the effective isolation of foreign facilities is indicated by a difference in potential readings on either side of the isolation kit, as well as a maximum potential shift of 10 mv, on the foreign facility. If a potential shift is noted on the foreign facility, additional testing will be undertaken to determine if an interference problem is present or a totally or partially shorted isolation kit is present. An isolation kit testing instrument can be used, such as a Tinker and Razor Model 601 instrument to test the effectiveness of the sleeves and gasket of the isolation device.

   Where bond wires are in place across the isolation kits within the Enbridge piping system, pipe to soil potentials using a common half-cell position shall be obtained while simultaneously interrupting the rectifiers affecting that area during the annual survey. A potential difference of over 10 mv shall indicate a high resistance connection within the bond across the isolation kit and shall be repaired or replaced.

   Visual examination of the bond wires across the isolation kits shall be noted on the same cycle as the rectifier output maintenance program. Any bond found to be broken or high resistant shall be replaced and tested by the above noted potential measurement procedure, with the rectifiers left operating. Separate testing of the isolation kit integrity using an isolation kit testing instrument on isolation kits which are intentionally bonded across may also be completed.

h. Isolation kits to foreign tie-ins or isolation kits not bonded across with a wire, within a hazardous areas shall have the space between the faces of the isolated flanges equipped with a barrier material such as a multilayer tape coating or non-conductive shield to prevent accidental arching due to contact across the flange body and face by a metallic object or tool. Flanges with a bond wire across them shall be inspected to determine proper contact and integrity of the bond wire. Where disassembly or removal of piping or isolation kits in a known hazardous operating condition, the rectifier affecting that area shall also be turned off and the piping shall be bonded across with a jumper cable to prevent arching by removal or creation of a metallic return path.

i. Where pipelines cross or run parallel to HVAC or HVDC transmission towers, testing shall be conducted to determine if adverse effects are present. This may include AC pipe to soil potential measurements taken at test points in the area. Any remedial measures to correct problems encountered shall be determined by the degree or type of problem encountered. This may include installation of magnesium anodes attached to the pipeline through a test station, installation of surge or AC fault protection at isolation kits in the area, installation of grounding mats at points where contact to the pipeline will occur such as valve sites or test point sites, requirement of all grounding cables on HVAC right-of-ways be coated cable within a 100 foot radius of the pipeline at crossing points, or other measures.

5. Preparation of Cathodic Protection Survey Report

   a. A report shall be prepared recording the readings of measurements taken, condition of the cathodic protection system repairs, required, if any.

   b. Refer to trouble report and cathodic protection report form (Exhibit 3.7-8) for samples of forms used to report troubles and record changes or repairs to the cathodic protection system by field personnel as directed by the appropriate supervisor.

   c. Reports for cathodic protection surveys shall be maintained at the Minot Office for the useful life of the section of pipeline to which they relate. The reports shall be available for review by the Department of Transportation.

C. CATHODIC PROTECTION RECTIFIER INSPECTION

1. Frequency

   a. All rectifiers, reverse current switches using diodes, as well as critical interference bonds shall be checked electrically and data recorded at least six times per year but with intervals not exceeding two and one-half (2 1/2) months. (See Exhibit 3.7-1 for rectifier locations.)

      All other non-critical interference bonds or bonds across isolation kits shall be checked electrically once each calendar year, but with intervals not exceeding fifteen (15) months. Typically this is completed during the annual cathodic protection survey.

   b. As part of a preventive maintenance program, all units shall be checked annually to minimize in-service failures. This check shall include inspections for electrical shorts, ground connections, meter accuracy, efficiency, and circuit resistance.

F. PIPE COATING

1. General

Each component of all underground structures shall be provided with an external surface coating selected specifically to provide adequate protection from external corrosion in the environment in which the component will be operated.

2. Material

a. Coatings should be selected on the basis of performance characteristics. Current required for cathodic protection on operating pipelines in similar environments may be a principal measure of performance. Results of laboratory tests, which relate to the current required for protection, may also be used.

b. Materials should be specified by manufacturer, type, and, where possible, by NACE or other recognized specifications.

c. Coating material for external corrosion control must:
   I. be designed to mitigate corrosion of the buried or submerged pipeline,
   II. have sufficient adhesion to the metal surface to prevent under film migration of moisture,
   III. be sufficiently ductile to resist cracking,
   IV. have enough strength to resist damage due to handling and soil stress,
   V. support any supplemental cathodic protection, and
   VI. if the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

3. Atmospheric Protection

Each component of the pipeline system that is exposed to the atmosphere shall be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. Protective coating or paint shall be applied to a clean surface and shall be suitable material to provide adequate protection from the environment. This protection shall be maintained. If no active corrosion is present then painting is for aesthetics; not a maintenance function.

Inspections shall be conducted at least once every three (3) calendar years, but with intervals not exceeding 39 months.

ENBRIDGE PIPELINES (NORTH DAKOTA) LLC

MAINTENANCE PROCEDURES

SECTION 3.0

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3.8 INSPECTION OF BREAKOUT TANKS

CONTENTS

EXHIBITS

A. U.S. DEPARTMENT OF TRANSPORTATION REQUIREMENTS

Operator shall:

1. At intervals not exceeding fifteen (15) months but at least once each calendar year, inspect each breakout vessel including atmospheric and pressure tanks,

2. Provide a means to contain hazardous liquids in the event of a spill or tank failure,

3. Adequately protect tank areas from unauthorized entry,

4. Provide normal and emergency relief valves for each tank,

5. Document and maintain records of each tank inspection (annual inspection) and record the condition, maintenance performed and repairs needed.

6. Perform in-service inspections of tanks according to Section 4 of the API Standard 653.

B. PRESSURE TANKS

The Enbridge Pipelines' System uses no pressure tanks.

C. ATMOSPHERIC TANKS

1. General

a. Atmospheric tanks, which comprise all of the tanks in the pipeline system, are more complex than pressure tanks. The tanks themselves are susceptible to damage or destruction from the effects of fire, corrosion, weather conditions, or improper operations. Various appurtenances and special features on the tanks serve to offset the inherent hazards and guard against damaging conditions.

b. These types may be broadly classified according to the type of roof and further classified as to the structural design of the roof (refer to Section 3.1), as follows:

i. Cone roof tanks.

ii. Floating roof tanks (pan, pontoon, double deck, hi-deck, or low deck structural roof designs).

iii. Covered internal floating roof tanks (pan and pontoon).

c. Cone roof tanks, with their fixed roof, have a dead air or vapor space between the liquid level and roof. Depending on the commodity being stored, vapors filling this space may corrode the inside surfaces of the roof, structural roof supports and upper rings of the tank shell.

d. Floating roof tanks, with their roofs riding at the liquid level, have advantages over cone roof tanks in that they improve vapor conservation, reduce fire hazards and retard internal corrosion.

e. Routine in-service visual inspections are done when field personnel visit a station. This takes place at a minimum weekly. Requirements are that these inspection periods not exceed one month. During such inspections, field personnel shall note any leaks, shell distortions, signs of settlement, corrosion, deterioration of the foundation, condition of the paint and appurtenances. Areas of concern shall be documented by a Trouble Report.

f. Scheduled in-service inspections shall not exceed 5 years unless the rate of corrosion dictates a more frequent time table. These inspections are to be done by an individual qualified to do so per API 653 Section 4. These inspections are the responsibility of the area supervisor. In addition to those items inspected during the annual inspection, the ultrasonic readings shall be taken and recorded on the annual tank inspection form. Frequency as dictated above.

g. Internal tank inspections shall be made to determine conditions of floor shell plates with respect to corrosion. Inspection intervals not to exceed 20 years.

h. Tank records shall consist of construction records, inspection history, and repair/alteration history.

2. Tank Dikes or Fire Walls

   a. Purpose:

      An earthen wall or dike is constructed around each tank to retain the liquid commodity in case of tank failure and protect station property and personnel from the hazards of fire.

   b. Care:

      i. Earthen dikes shall be maintained at original cross section dimensions to compensate for wind or water erosion. To reduce erosion, dikes are covered with gravel or rocks.

      ii. Soil lost by erosion shall be replaced to provide original cross-section dimensions of the dike. Vegetation shall be removed by pulling or sterilant applied by professional contractors.

   c. Inspection:

      i. Inspection shall be made of the tank dike to see that erosion or damage has not taken place and that the dike and reservoir area is free of brush, debris or other objects.

      ii. Determination shall be made as to the capacity of the reservoir formed by the dike around the tank to assure it is greater than the capacity of the tank.

3. Tank Foundations

   a. Purpose:

      i. The tank foundation is to provide a level and firm base to support and hold the tank in its original shape. Uneven settling places dangerous stresses on the tank structure.

Professional tank contractors having the required skills, sophisticated tools and work equipment may need to be employed if possible for such inspections.

Internal tank inspections, whether for inspecting the covered floating roofs, supporting structures, or tank bottoms, should only be undertaken when there are indications that there are serious hazards or difficulties present that require immediate correction.

D. TANK INSPECTION REPORTS

1. When tank inspections are required, the Annual Inspection of Breakout Tanks report form (See Exhibit 3.8-1) shall be used for recording results of the inspections. The Seal Gap report (See Exhibit 3.8-2) shall be used for gap measurements.

2. Tank inspections shall be made at intervals not exceeding fifteen (15) months but at least once each calendar year.

3. Notations on tank inspection reports shall be made of tanks, fire walls, foundations and appurtenances requiring maintenance, repairs or replacement. Any problems or deficiencies shall be noted on a Trouble Report for the supervisors handling.

4. Maintenance and repairs shall be undertaken at the earliest practicable time and documentation of the work performed shall be entered on the trouble report to be filed with the tank inspection reports.

5. The tank inspection reports and pertinent maintenance records shall be maintained at the Minot Office to ensure that the documents are available for U.S. Department of Transportation review.

6. An internal tank inspection may be conducted by qualified individuals when a tank is cleaned and taken out of service. The qualified individual's recommendations shall be reviewed by management before putting tank back in service.

E. SAFETY

1. Protection against ignitions from static electricity, lightning, or maintenance activities must be in accordance with API RP 2003.

2. The hazards associated with access/egress onto floating roofs of in-service

tanks to perform inspections, maintenance or other duties must be done in accordance with items listed in API 2026 (Safe Descent onto Floating Roofs of Tanks in Petroleum Service). Attention shall be given to the need for SCBA's, backup individuals, fire hazards, falling, and the general tank condition. Many of the same safeguards are addressed in the section of this manual dealing with Confined Space entry and on page 10 of this section under Safety Precautions.

f. The full encirclement is then placed on the pipeline and held in place by chains and jacks. After the sleeves are properly nested, tack welds are placed about six (6) inches apart along each seam preparatory to applying the root and filler beads. When one welder is used, welding shall be alternated from one side of the sleeve to the other to equalize contraction and stress on the tack welds or root bead on the opposite side. After the root beads have been deposited on both longitudinal seams, the jacks and chains may be removed to facilitate completion of the weld.

g. After completion of the longitudinal seam welds, the end welds are made by starting at the bottom center of the pipe and progressing upward to the top center. Welding should be completed at one end of the sleeve before starting on opposite end.

4. <u>Removal of Pipe to be Replaced</u>

a. Pipe to be replaced shall be removed by cutting out in a cylindrical section the damaged pipe. Cuts shall be made with manually-operated or air driven pipe cutters or saws.

b. Due to the possibility of arcing, rectifiers located on either side of the work location shall be turned off, as applicable. Before the line is cut or a flange joint is separated, bonding clamps will be used on all points of separation. If replacement pipe is required, pipe joint(s) shall also be bonded. Areas where excessive current is on the line, additional protection shall be provided by installing ground rods on each side of the cut or flange separation.

c. Where vapor seals or mud plugs are relied upon to seal off the escape of vapors from a pipeline and the pipe is jarred so as to render the seal ineffective, work shall be stopped until a check for vapors shows it is safe to proceed.

d. Some positive method of venting should be used to prevent vapor pressure buildup in the line. Venting may be accomplished by installing vent connections or by using expansion plugs containing a connection for a vent line.

5. <u>Pipe and Component Replacement</u>

a. Joints of pipe and components that are to be used in line repairs or relocations shall be hydrostatically tested.

b. The tests shall be made in accordance with the procedures as covered in Section 3.12, "Hydrostatic Testing", of this Manual.

c. The pre-tested pipe will be marked with the necessary information and warehoused in a manner so that it will be immediately available for line repair work.

d. The strength of the replacement pipe and/or components shall be the same as or higher than that of the pipe/components being replaced.

e. Pipe shall be jointed by butt welds, weld end collar (Exhibit 3.9-6) or a combination of both. When inserting the new section of pipe by butt welding, welding shall be done in conformance with API Standard 1104.

f. Prior to welding, all commodity and saturated earth shall be removed from within and around the excavation.

g. Prior to welding, the excavation shall be tested with an indicator to determine that the excavation is vapor free. It might be necessary to spread dry dirt or ABC fire extinguisher powder on the bottom and around the excavation to eliminate vapors.

h. If commodity seeps into the excavation after welding has began, the product shall be removed and the excavation again freed of vapor before welding is resumed.

i. Bending of pipe must not produce wrinkles in pipe or impair serviceability of pipe. Longitudinal seams shall be placed in a neutral axis of the bend.

6. <u>Pipe Coating</u>

After repairs are completed, the pipe shall be thoroughly cleaned and re-coated. Application of the coating material shall be in accordance with the coating manufacturer's recommendations.

On any repair or new construction, prior to pipe being lowered into the ditch, a holiday detector (jeep) must be used to check the coating for any defects (scratches, bare spots, pinholes, etc.). All defects must be coated and re-taped prior to lowering the pipe.

H. PIPE TAPPING AND STOPPLE OPERATION

1. <u>General</u>

a. As mentioned near the beginning of the subsection "Pipe Repairs", it is possible to replace a damaged pipe section without shutting down service by hot tapping the line and installing a bypass. When this is necessary, special tapping equipment, stopple plugging equipment and bypass fittings are used. (See Exhibits 3.9-7 and 3.9-8)

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3. The carrier shall:

   a. Keep detailed records of the tests that qualify with welding procedures.

   b. Maintain records of the qualifying tests given to each welder and the detailed results of each test.

   c. Maintain a list of qualified welders and the welding procedures in which they are qualified.

B. PROCEDURE QUALIFICAITON

1. Prior to any welder qualification or production welding, the welding procedure for the types of welds to be made, such as butt, socket and fillet, shall be qualified and documented as specified herein. It is important that the Contractor be aware of the relation of the "Essential Variables" contained in API Standard 1104, Section 2.4, to the welding procedure. Whenever a change involving one or more of these variables takes place, the Contractor shall modify and requalify the welding procedure in compliance with the applicable information contained in these specifications. Changes of variables other than those listed will not require a procedure requalification, provided that the procedure specification and qualification records are revised to show these changes.

   In addition to the "Essential Variables" contained in API 1104, Section 2.4, the number of welders shall be considered essential. Therefore, the Contractor shall qualify the procedure with the same number of welders which will be used in production welding.

2. Welding procedures shall be qualified by destructive testing and nondestructive testing according to the 18th Edition of the API Standard 1104, Section 2.0, or Section 8.0. Butt weld destructive test specimens shall be taken at the locations shown in Exhibit 3.10-1 (Figure 3), "Location of Test Specimens for Procedure Qualification: Test Butt Welds". Fillet weld, socket weld, and branch connection weld destructive test specimens shall be taken at the locations shown in Exhibit 3.10-2 (Figure 10), "Location of Nick-Break Test Specimens – Fillet Weld Procedure and Welder Qualification Test Welds". Tests shall be conducted in the presence of Company representative and the results recorded by him on the form titled "Coupon Test Report". (See Exhibit 3.10-4)

For the second test, the welder shall lay out, cut, fit, and weld a full-size branch-on-pipe connection. This test shall be made with pipe whose diameter is at least 6 5/8 inches (168.3 millimeters) and whose nominal wall thickness is at least one-fourth inch (6.35 milli-meters). A full-size hole shall be cut in the run. The weld shall be made with the run-pipe axis in the horizontal position and the branch-pipe axis extending vertically downward from the run. The finished weld shall exhibit a neat, uniform workmanlike appearance.

The weld shall exhibit complete penetration around the entire circumference. Completed root beads shall not contain any burn-through of more than one-fourth inch (6.35 millimeters). The sum of the maximum dimensions of sep-arate unrepaired burn-throughs in any continuous 12-inch (304.8 millimeter) length of weld shall not exceed one-half inch (12.7 millimeters).

Four nick-break specimens shall be removed from the weld at the locations shown in Figure 10. They shall be pre-pared and tested in accordance with 2.8.1 and 2.8.2. The exposed surfaces shall meet the requirements of 2.8.3.

2. A welder who has successfully completed the butt-weld qualification test described in 3.3.1 on pipe whose diameter is greater than or equal to 12 ¾ inches (323.8 millimeters) and a full-size branch-connection weld on pipe whose diameter is greater than or equal to 12 ¾ inches (323.8 millimeters) shall be qualified to weld in all positions; on all wall thickness, joint designs, and fittings; and on all pipe diameters. A welder who has successfully completed the butt-weld and branch-connection requirements of 3.3.1 on pipe whose diameter is less than 12 ¾ inches (323.8 millimeters) shall be qualified to weld in all positions; on all wall thickness, joint designs, and fittings; and on all pipe diameters less than or equal to the diameter used by the welder in the quali-fication tests.

D. <u>WELDER/WELDING EQUIPMENT AND WELDER QUALIFICATION</u>

1. Prior to production welding, each welder shall pass a Welding Qualification Test in accordance with the 18th Edition of the API Standard 1104, Section 3. It is important that the Contractor be aware of the relation of the "Essential Vari-ables" contained in API Standard 1104, Section 3.22, to the welder's qualifi-cation. Whenever there is a change involving one or more of these variables, the Contractor shall requalify the welders.

2. Pipeline welder shall be required to pass a Butt Weld Test (Single Qualification). Each welder shall make a complete butt weld and test specimens shall be removed – as per Figure 12.

Issued: 12/02/02-R

a. The nominal wall thickness of adjoining pipe ends is internally offset more than 3/32" but less than ½ the wall thickness of the thinner pipe;

b. In the opinion of the Company engineer, the root bead shows signs of internal undercut or lack of penetration;

c. A fitting is being welded to a pipe.

2. When back-up welding is required due to varying inside diameters, it shall be made any time after the second O.D. pass.

3. When back-up welding is used, the root bead shall be background to clean metal with a power grinder.

4. All back-up welding shall be done with the same electrode used on the stringer bead.

L. PREHEATING

1. Preheating to 200° F shall be required under the following conditions:

   a. When the base metal temperature is below 40° F,

   b. When water or moisture is present on the pipe.

2. The preheat area shall include the entire circumference of the joint for a minimum distance of 3" back from each weld.

3. Preheat temperature shall be checked with temperature indicating crayons.

4. Insulating blankets will be wrapped around the weld area as soon as the weld in completed and remain until the weld is cooled down.

M. IDENTIFICATION OF WELDS

1. Defects located by non-destructive methods, radiography, or visual inspection shall be accepted or rejected by the Company engineer in accordance with the parameters set forth in the 18th Edition of API Standard 1104, and Part 195 of Title 49 of the Code of Federal Regulations and the latest amendments thereto, issued by the Department of Transportation, Office of Pipeline Safety Operations.

high H_2S exposure. When an alarm sounds, retreat upwind to a safe area. If necessary to re-enter area, wear proper breathing protection. Follow manufacturers operating instructions.

The Safety Department sees that appropriate tests are made at individual field leases and station tanks to verify levels of H_2S per Enbridge's Hydrogen Sulfide Safety Program. The Area Supervisor will notify field personnel of any changes.

2. Confined space is any space having limited access or egress that is subject to the accumulation of toxic or flammable contaminants or be an oxygen deficient atmosphere. Confined spaces must be considered immediately dangerous to life and health until proven otherwise. The following procedures should apply. Areas that would be confined spaces in Enbridge's operations are: inside of tanks, top side of external floating roof tanks, excavations for pipe repairs or where the possibility of toxic gases accumulating is possible.

3. Another dangerous aspect of pipeline operation is working in areas where a flammable vapor of liquid may exist. To minimize the possibility of ignition, use of an open flame is prohibited around tanks and pump station equipment and piping unless presence of no flammable vapors has been determined. When in these areas, employees are not to use tools in a manner that poses a threat of sparks, i.e., striking tools or objects or using non-explosion proof electrical equipment, without proper gas detection monitoring and/or forced ventilation. Smoking is not allowed at any Enbridge facility with the exception of designated smoking areas at the Minot Station.

F. POST-INCIDENT REVIEW

1. While assessing any damage, the following criteria shall be reviewed:

a. Cause (use of drawings, pictures, etc., to help with description)

b. Effectiveness of the manual for instruction regarding prevention of the accident as well as the action taken.

2. Corrective action shall be taken where the review reveals deficiencies and may include pipe replacement, sleeving, etc.

3. Corrective action shall be taken to minimize reoccurrence of incidents.

G. VEHICLE OPERATION GUIDELINES

1. Following Distance:

Issued: 03/10/03-R

4. Mail campaigns with brochures.

5. Annual meetings with local contractors informing them of all underground utilities in the area. Obtaining names of contractors doing work in area by list of those attending said banquets.

6. Phone number listings in telephone companies directories serving area along the pipeline right-of-way.

7. Membership in "One-Call" notification systems; such as, Minnesota's Gopher State One Call (1-800-252-1166), Montana's One Call (1-800-424-5555) and North Dakota's One Call (1-800-795-0555).

Choice of method used shall be made on a basis of effectiveness and efficiency. Records shall be maintained showing the date of the contact, who was contacted, and the method of contact and information exchanged. In the case of programs using the media, the date of publication and the area covered will be recorded.

Liaison will be established and maintained with fire, sheriff, and appropriate public officials (local emergency managers) in order to learn the responsibility and resources of each governmental organization that may respond to a hazardous liquid pipeline emergency and means of communication.

As part of Damage Prevention Program, Enbridge shall use yellow flags with company name and/or paint markings to indicate the presence of subsurface structures in areas of excavation prior to activity beginning. Company personnel should be present during excavation and shall inspect prior to back filling. Blasting and/or directional boring shall not be allowed in close proximity to the pipeline without management approval.

A leakage survey shall be conducted after any blasting or directional boring has occurred.

J. VISITORS

Visitors to the field (including office employees) must report to the field office or control room upon arrival. Visitors must wear hard hats, safety footwear and hearing protection in designated areas. Visitors must stay clear of any areas designated by the employee responsible for the site.

NOTE: The employee responsible for the site may exempt visitors on a supervised/ controlled tour from foot protection requirements.

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 7, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5006M

Dear Mr. Tutcher:

As a result of an inspection of your procedural manuals on June 17-21, 2002, by representatives of the Central Region, Office of Pipeline Safety (OPS) and the Minnesota Office of Pipeline Safety (MNOPS), at Enbridge Pipelines North Dakota's Minot, ND office, a Notice of Amendment was issued on February 25, 2003. This Notice required amendment of certain procedures contained within Enbridge Pipelines North Dakota's Operation and Maintenance Procedural manuals. We received correspondence and copies of amended pages of Enbridge Pipelines North Dakota's Operation and Maintenance Procedural manuals, submitted by Enbridge Pipelines North Dakota by letter dated March 26, 2003. The revised procedures have been reviewed and found to be acceptable.

This letter is to inform you that no further action is necessary and that this case is being closed. Thank you for your cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc Mr. Mark Kinbloom
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Mr. Boyd Haugrose
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St. Paul, Minnesota 55101-5147

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 3, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5009M

Dear Mr. Tutcher:

On June 3-7, 2002, representatives of the Central Region, Office of Pipeline Safety, and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted a joint team onsite pipeline safety inspection of your Operation and Maintenance Procedural manuals at Duluth, MN.

As a result of the inspection, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

§195.402 Procedural manual for operations, maintenance, and emergencies.

§195.402(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

Review of Enbridge Energy's O&M procedural manuals found the procedures were inadequate. The procedures require expansion to include additional detail in regard to the following items, as reviewed with your personnel during the inspection:

A. General Items.

1. **§195.402(a) The manual required by §195.402(a) shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective.**

The operator's O & M manual makes direct reference to various operator Engineering Standards, however the procedure does not require that the Engineering Standards should be reviewed on an annual basis.

B. Maintenance and Normal Operations Items.

§195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

2. **§195.402(c)(1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance.**

The procedure did not not provide clear direction concerning the minimum distribution requirements for drawings and drawing revisions.

3. **§195.402(c)(2) Gathering of data needed for reporting accidents under Subpart B of this part in a timely and effective manner.**

a) §195.50 Reporting accidents.

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

§195.50(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

(1) Not otherwise reportable under this section;
(2) Not one described in Sec. 195.52(a)(4);

(3) Confined to company property or pipeline right-of-way; and
(4) Cleaned up promptly;

The procedure did not include the new 5 gallon reporting requirements for a product release.

b) §195.54 Accident reports.

§195.54(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

The procedure is inadequate because it restricts the filing of a supplemental report to only when there are changes that the operator considers "significant changes" instead of "any changes" as the regulation requires.

4. **§195.402(c)(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.**

a) §195.120 Passage of internal inspection devices.

§195.120(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

The procedure did not provide clear direction concerning making all components piggable.

b) §195.214 Welding: General.

(1) §195.214(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

The procedure did not provide clear direction requiring the quality of test welds used to qualify welding procedures to be determined by destructive testing.

(2) §195.214(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

The procedure did not provide specific direction on what welding procedure details and qualification tests results shall be recorded.

c) §195.234 Welds: Nondestructive testing.

§195.234(b) Any nondestructive testing of welds must be performed-

(1) In accordance with a written set of procedures for nondestructive testing; and
(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

The procedure did not provide clear direction on specific procedures for non-destructive testing or clear direction about the process of operator approval for contractor non-destructive testing methods.

d) §195.266 Construction records.

A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility:

(a) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.
(b) The amount, location, and cover of each size of pipe installed.
(c) The location of each crossing of another pipeline.
(d) The location of each buried utility crossing.
(e) The location of each overhead crossing.

(f) The location of each valve and corrosion test station.

The procedure did not not provide clear direction concerning recording the total number of girth welds and the number nondestructively tested, the number rejected and the disposition of each rejected weld.

e) §195.306 Test medium.

§195.306(b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if-

> **(1) The entire pipeline under test is outside of cities and other populated areas;**
> **(2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;**
> **(3) The test section is kept under surveillance by regular patrols during the test; and,**
> **(4) Continuous communication is maintained along entire test section.**

The procedure did not include the criteria for using crude oil as a pressure test medium.

f) §195.308 Testing of tie-ins.

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

The procedure did not provide clear direction on whether tie-in pipe is to be tested with the section to be tied in or is to be tested separately.

g) §195.310 Records.

§195.310(b) The record required by paragraph (a) of this section must include:

§195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over

the entire length of the test section.

The procedure did not include a requirement for providing a profile whenever there is a 100' elevation difference as part of the pressure test records.

h) §195.403 Training.

1) §195.403(b) At intervals not exceeding 15 months, but at least once each calendar year, the operator shall:

(a) §195.403(b)(1) Review with personnel their performance in meeting the objectives the training program set forth in paragraph (a) of this section;

The procedure did not provide clear direction that for emergency response training there shall be reviews of personnel performance once each calendar year not exceeding 15 months.

(b) §195.403(b)(2) Make appropriate changes to the training program as necessary to ensure that it is effective.

The procedure did not provide clear direction concerning making appropriate changes to emergency response training as needed to insure that the training is effective.

2) §195.403(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the procedures established under 195.402 for which they are responsible to insure [sic] compliance.

The procedure did not provide clear direction concerning how supervisors maintain knowledge of the emergency response procedures for which supervisors are responsible.

i) §195.404 Maps and Records.

§195.404(b) Each operator shall maintain for at least 3 years daily operating records that indicate-

§195.404(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

The procedure is inadequate because Table 3 of Enbridge's "Pipeline Operations Records" has not been revised to include abnormal operation records that are recorded using "FACMAN" software.

j) §195.410 Line markers.

§195.410(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

> **a) §195.410(a)(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.**
>
> The procedure did not provide clear direction concerning what other line marker locations are sufficient to accurately locate the line.
>
> **b) §195.410(c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.**
>
> The procedure did not provide clear direction concerning line markers in aboveground areas accessible to the public.

k) §195.412 Inspection of rights-of-way and crossings under navigable waters.

> **a) §195.412(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.**
>
> The procedure is inadequate because it restricts follow up on items found during right-of-way

inspections to only items that Enbridge considers "significant" and it does not make clear that follow up action, if needed, must be for all items requiring inspection under the regulations and not just what Enbridge considers "significant".

b) §195.412(b) **Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.**

The procedure did not provide clear direction concerning what specific crossing components are to be inspected during a waterway inspection.

l) §195.420 Valve maintenance.

§195.420(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

The procedure did not provide clear direction concerning maintaining all valves necessary for the safe operation of the operator's pipeline system.

m) §195.422 Pipeline repairs.

§195.422(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

The procedure did not include an overview statement that replacement components shall be designed and have a maximum operating pressure compatible with existing facilities. Additionally, the procedure did not reference company Engineering Standards.

n) §195.428 Overpressure safety devices.

§195.428(d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

The procedure is inadequate because the tank internal inspection table included in the O & M manual did not include the testing of overfill protection systems on breakout tanks, including the NGL breakout tanks.

o) §195.555 What are the qualifications for supervisors?

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402(c)(3) for which they are responsible for insuring compliance.

The procedure did not provide clear direction concerning corrosion control supervisors must maintain knowledge of that portion of the corrosion control procedures for which the supervisors are responsible.

p) §195.569 Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

The procedure did not provide clear direction concerning examining all exposed pipe whenever the operator has knowledge of exposed pipe.

q) §195.573 What must I do to monitor external corrosion control?

§195.573(a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

> **a) §195.573(a)(2) Identify before December 29, 2003 or not more than 2 years after cathodic**

protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

The procedure did not provide clear direction concerning the criteria for a close interval survey and when a close interval survey is required.

b) §195.573(e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

The procedure did not provide clear direction concerning the criteria to determine if a deficiency involves a pipeline under an integrity management program and clear direction on what the time intervals are for completing repairs on deficiencies.

r) §195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

§195.575(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

§195.575(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

§195.575(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

§195.575(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

§195.575(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

The procedure did not provide clear direction concerning what facilities require electrical isolation and what inspections, tests and additional safeguards are required.

s) §195.577 What must I do to alleviate interference currents?

§195.577(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

§195.577(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

The procedure did not provide clear direction concerning designing and installing cathodic protection systems to minimize effects on existing adjacent metallic structures.

t) §195.579 What must I do to mitigate internal corrosion?

§195.579(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

The procedure did not provide clear direction concerning checking adjacent pipe when internal corrosion is found.

u) §195.589 What corrosion control information do I have to maintain?

§195.589(a) You must maintain current records or maps to show the location of--

> **(1) Cathodically protected pipelines;**
> **(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and**
> **(3) Neighboring structures bonded to cathodic protection systems.**

§195.589(b) 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.

§195.589(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

(1) The procedure did not provide clear direction concerning the criteria for records retention periods for corrosion control information.

(2) The procedure did not provide clear direction concerning documenting all inspections performed under §195.583, even when no corrective action is needed.

5. **§195.402(c)(5) Analyzing pipeline accidents to determine their causes.**

The procedure did not provide clear direction concerning analyzing accidents to determine their causes.

6. **§195.402(c)(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.**

The procedure did not provide clear direction concerning minimizing the potential for hazards and minimizing the possibility of recurrence of accidents.

7. **§195.402(c)(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §195.59 of this part.**

The procedure did not provide clear direction concerning filing reports under §195.59.

C. Safety-Related Condition Report Items.

8. **§195.402(f) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §195.55.**

The procedure did not provide clear direction concerning recognition and discovery of safety-related conditions.

a) **§195.55 Reporting safety-related conditions.**

§195.55(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving pipelines in service:

§195.55(a)(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion

pitting to a degree where leakage might result.

The procedure did not include adequate guidance on general and localized corrosion as a safety-related condition.

b) **§195.56 Filing safety-related condition reports.**

§195.56(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

> **(1) Name and principal address of operator.**
> **(2) Date of report.**
> **(3) Name, job title, and business telephone number of person submitting the report.**
> **(4) Name, job title, and business telephone number of person who determined that the condition exists.**
> **(5) Date condition was discovered and date condition was first determined to exist.**
> **(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.**
> **(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.**
> **(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.**

The procedure did not specifically include direction covering the eight informational elements that must be included in a safety-related condition report.

As provided in 49 C.F.R. §190.237, this Notice of Amendment serves as your notification that this office considers your procedures inadequate. Under 49 C.F.R. § 190.237, you have a right to submit written comments or request an informal hearing.

You must submit written comments or a request for a hearing within 30 days after receipt of this Notice. After reviewing the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 C.F.R. § 190.237. If you do not wish to contest this Notice of Amendment, please provide your revised procedures within 30 days of receipt of this notice.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
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ENBRIDGE™

March 31, 2003

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2003-5009M

On March 6, 2003, this office received the above reference Notice of Amendment which resulted from an Operation and Maintenance Procedural manual audit conducted in Duluth, MN, on June 3-7, 2002. While Enbridge does not wish to contest this Notice of Amendment, we do require additional time beyond the 30 days after receipt of notice to compile the revised procedures for submission to your office. Enbridge, therefore, respectfully requests an extension of 14 days in which to respond to this notice.

Sincerely,

John R. Sobojinski

c: John Hayes
Dan Tutcher
Greg Sevick
Law

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 2, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
~~Houston, TX 77002-7002~~

CPF No. 3-2003-5009M

Dear Mr. Tutcher:

The Office of Pipeline Safety, Central Region received correspondence from Mr. John Sobojinski requesting additional time to respond to the Notice of Amendment issued by this office on March 3, 2003.

We have reviewed the extension request and find that it is not unreasonable. Therefore, Enbridge (U.S.), Inc.'s request for an extension is granted. Please ensure that the specific procedural revisions arrive at the Central Region Office no later than May 2, 2003.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. John Sobojinski
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
21 West Superior Street
Duluth, MN 55802-2067

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

May 1, 2003

Mr. Charles Kenow, Administrator
Minnesota Office of Pipeline Safety
444 Cedar Street
Suite 147-N, Town Square
St. Paul, Minnesota 55101-5147

Dear Mr. Kenow:

Enclosed is a copy of the response received by OPS Central Region from Enbridge (U.S.), Inc. regarding CPF No. 3-2003-5009M that was issued on March 3, 2003.

Please review Enbridge's proposed revisions to their Operations and Maintenance Procedural Manual and inform OPS Central Region if the revisions are acceptable to the Minnesota Office of Pipeline Safety.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enclosure

cc Mr. Boyd Haugrose w/encl
Minnesota Office of Pipeline Safety
31332 County Hwy 34
Ogema, MN 56569

Mr. Brian Pierzina w/encl
Minnesota Office of Pipeline Safety
607 NW 5th Street, Suite 103
Grand Rapids, MN 55744

Dave Barrett

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 23, 2003

Mr. Dan C. Tutcher
President
Enbridge (U.S.), Inc.
Suite 2950
1100 Louisiana
Houston, TX 77002-7002

CPF No. 3-2003-5009M

Dear Mr. Tutcher:

As a result of an inspection of your Operation and Maintenance Procedural manuals on June 3-7, 2002, by representatives of the Central Region, Office of Pipeline Safety (OPS) and the Minnesota Office of Pipeline Safety (MNOPS), at Enbridge's Duluth, MN office, a Notice of Amendment was issued on March 3, 2003. This Notice required amendment of certain procedures contained within Enbridge's Operation and Maintenance Procedural manuals. We received correspondence and copies of amended pages of Enbridge's Operation and Maintenance Procedural manuals, submitted by Enbridge by letter dated April 28, 2003. The revised procedures have been reviewed and found to be acceptable.

This letter is to inform you that no further action is necessary and that this case is being closed. Thank you for your cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc Mr. Mark J. Willoughby
Manager, U.S. Compliance & Risk Management
Enbridge (U.S.) Inc.
119 North 25th Street East
Superior, WI 54880

Mr. Charles Kenow, Administrator
Minnesota Office of Pipeline Safety
444 Cedar Street
Suite 147-N, Town Square
St. Paul, Minnesota 55101-5147

Mr. Boyd Haugrose
Minnesota Office of Pipeline Safety
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Enbridge Pipelines (Lakehead) L.L.C.
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John R. Sobojinski
Manager,
U.S. Compliance & Risk Management
Tel 715 394 1505
Fax 715 394 1500
john.sobojinski@enbridge.com

ENBRIDGE™

April 28, 2003

VIA UPS NEXT DAY MAIL

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
901 Locust, Room 462
Kansas City, MO 64106-2641

Dear Mr. Huntoon:

CPF No. 3-2003-5009M

On June 3-7, 2002, representatives of the Central Region, Office of Pipeline Safety, and the Minnesota Office of Pipeline Safety conducted a joint team onsite inspection of our Operations and Maintenance Procedural manuals. As a result of this inspection, on March 6, 2003, this office received the above referenced Notice of Amendment. In response to this notice, Enbridge is hereby submitting revisions to our manuals as provided for in 49 C.F.R. Section 190.237.

If you should have any further questions or concerns about any of the items referenced in your notice, please contact me at (715) 394-1505.

Sincerely,

John R. Sobojinski

Attachment

c: John Hayes
Greg Sevick
Tom Fridel
Mark Sitek
Dan Tutcher
Law Department

A. General Items.

1. 195.402 (a) The Manual required by 195.402 (a) shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective.

The Operator's O&MP manual makes direct reference to various operator Engineering Standards, however the procedure does not require that the Engineering Standards should be reviewed on an annual basis.

A section is being added to the O&MP Manual to identify all Engineering Standards that the O&MP Manual makes direct reference to and yearly reviews, not exceeding 15 months, will be completed by the appropriate Subject Matter Experts within the Engineering Department.

This section will be issued as an interim procedure until the next revision of O & MP, Book 3; Pipeline Facilities is issued. This change has not been added to the O & MP manual due to an ongoing review of the manual series (Books 1 – 4) to ensure that all Engineering Standard references have been incorporated.

B. Maintenance and Normal Operations Items.

2. 195.402 (c) (1) Making construction records, maps, and operating history available as necessary for safety operation and maintenance.

The procedure did not provide clear direction concerning the minimum distribution requirements for drawings and drawing revisions.

Table 3—*continued*
Pipeline Operations Records

Record	When	Responsibility	Distribution	Retention Location	Retention Period	Reference
Tank In-Service Inspection Report	after formal in-service inspection of atmospheric crude oil tank every 5 years minimum	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	until the next inspection	Book 3: Pipeline Facilities, 09-02-02, Tank Inspections
Tank Out-of-Service Inspection Report	after formal out-of-service inspection of atmospheric crude oil tank every 20 years minimum	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	until the next inspection	Book 3: Pipeline Facilities, 09-02-02, Tank Inspections
Pipeline Hydrotest Permit Request	10 weeks (CAN) or 26 weeks (USA) before the pressure test	test supervisor		Safety & Environment	permanently	Book 3: Pipeline Facilities, 07-02-01, Test Planning & Preparation
Pressure Test Report	after pressure testing	test supervisor	Engineering	Engineering	permanently	Book 3: Pipeline Facilities, 07-02-05, Hydrostatic Pressure Test
construction records, maps and drawings (USA)	as required after a facility is changed	PLM supervisor/ coordinator	as per Engineering Services database	Construction Project Management database; As-Built Tracking database	permanently	Engineering Drafting
valve operation, inspection and maintenance (USA)	semiannually	mechanical technician		Maximo	permanently	MP107; MP256
	annually					MP320; MP330; MP179

Drawing Maintenance and Distribution

As required under Part 195.402 (C) (1), Enbridge shall make current drawings available to appropriate personnel as described below.

Responsibilities

Note: Five types of drawings are designated critical to the operation and maintenance of the pipeline: 1) mainline route sheets, 2) flow diagrams, 3) electrical one-line diagrams, 4) site safety plot plan, and 5) mainline tie-in drawings.

Each Region must have access to a complete set of current critical drawings.

Engineering Services must maintain a complete current file of all critical drawings (both paper drawings and electronic format).

Critical drawings must be kept current to reflect additions, retirements, permanent repairs and the existence of foreign facilities. Engineering Services will ensure Critical Drawings are updated within 6 months of receipt of any changes, addition or deletions.

Mainline Route Sheets

Note: Mainline route sheets serve as the principal drawings illustrating the location of the pipeline with respect to legal land descriptions and details of access routes on the right-of-way (ROW).

Mainline route sheets must be maintained by Engineering Services. Route Sheets will be updated at least every 18 months.

Each Region must have copies of their respective route sheets available in the regional office, PLM facilities and appropriate company vehicles.

Additional distribution is location specific and is identified in Engineering Services database;
Drive N:\Eng. Services\Drawing Distribution.

Flow Diagrams

Flow Diagrams must be maintained by Engineering Services.

Flow Diagrams should be posted on the wall of the control room at attended locations, or within the main switchgear cubicle/building at unattended locations.

Electrical Diagrams

Electrical one-line diagrams and switching diagrams must be maintained by Engineering Services. One-line diagrams of the equipment within each switchgear cubicle/building and switching diagrams must be in a location accessible when operating or working on equipment.

Site Safety Plot Plan

Site safety plot plans must be maintained by Engineering Services. Site safety plot plan must be posted at location.

Mainline Tie-In Drawing

Mainline tie-in drawing must be maintained by Engineering Services. Each Region Office and station location must have a copy.

Note: Additional distribution of critical drawings is location specific and is identified in Engineering Services database; Drive N:\Eng. Services\Drawing Distribution.

Station & Terminal Drawings

Engineering Services is responsible for maintaining a complete set of working drawings for all Stations and Terminals. These drawings shall be kept current to reflect additions, retirements and modifications done to the site. The critical drawings are also included in this set.

Each Region Office, Technical Supervisor, Station/Terminal Site must have a copy of their respective locations.

Additional distribution of Station and Terminal working drawings are by request.

B. Maintenance and Normal Operations Items.

3. 195.402 (c) (2) Gathering of data needed for reporting accidents under Subpart B of this part in a timely and effective manner.

a) 195.50 Reporting accidents.

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulted in any of the following:

195.50 (b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is;

(1) Not otherwise reportable under this section;
(2) Not one described in Sec. 195.52 9 (a) (4);
(3) Confined to company property of pipeline right-of-way; and
(4) Cleaned up promptly;

The reporting did not include the new 5 gallon reporting requirements for a product release.

b) Accident reports.

195.54 (b) Whenever an operator received any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

The procedure is inadequate because it restricts the filing of a supplemental report to only when there are changes that the operator considers "significant changes" instead of "any changes" as the regulation requires.

Purpose

This standard identifies the applicable company and government requirements for internal and external incident reporting (see Table 1).

Table 1
Incident Reporting Requirements—USA

Reporting Criteria	Report	Submitter	Receiver	When	Comments
A pipeline failure in which a hazardous liquid is released that results in: • unintentional explosion or fire • loss of liquid hydrocarbon ≥5 gallons unless the release resulting from a PLM activity is: — reportable under other criteria — confined to company property or the ROW and cleaned up promptly • unintentional escape of NGL to atmosphere >5 gallons a day • pollution of any body of water that violates water quality standards, discolors the water surface or adjoining shoreline, or deposits sludge or emulsion beneath the water surface or adjoining shorelines • death of any person • personal injury necessitating hospitalization • estimated property damage, including cleanup and recovery, value of lost product and damage to the operator and/or others >$50,000 • an incident that regional management considers significant	Release Alert	regional management	as per Lotus Notes distribution	immediately	Compliance & Risk Management determines whether to complete and file an Accident Report Form 7000-1
	verbal		National Response Center (NRC)	within 2 hrs	(800) 424-8802 *24 hrs*
	Accident Report (DOT Form 7000-1)	Compliance & Risk Management	Office of Pipeline Safety (OPS)	within 30 days	
	supplemental report			within 30 days of receiving changes or additions	submit a supplemental report if there are any changes, additions, or unknown conditions at the time of initial report
In **North Dakota**, a pipeline leak or spill that: • contaminates waters above or below the earth • results in a fire	verbal	regional management	ND State Dept of Health ND Industrial Comm.-Oil and Gas Division	immediately	(701) 224-2121 *24 hrs* (701) 224-2969 *24 hrs*
In **Minnesota**, a pipeline leak or spill >5 gallons that: • contaminates waters above or below the earth (incl. into storm and sanitary sewers) or soil • meets federal reporting criteria			MN Dept Emerg Mgmt (state duty officer)		(800) 422-0798 *24 hrs*
In **Wisconsin**, a pipeline leak or spill into waters above or below the earth.			Wisconsin Div. of Emergency Govt.		(608) 266-3232 *24 hrs*
In **Michigan**, a pipeline leak or spill into waters above or below the earth (includes waters bordering the state).			Michigan Dept. of Natural Resources		(800) 292-4706 *24 hrs*
In **Illinois**, a pipeline leak or spill (any size) into the environment (includes waters above or below the earth, in air or on land, but excludes areas inside plant/facility boundaries).			Illinois Emerg. Serv. & Disaster Agency and nearest local emergency agency		(217) 782-7860 *24 hrs*

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

a) 195.120 Passage of internal inspection devices.

195.120 (a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

The procedure did not provide clear direction concerning making all components piggable.

Purpose

Pipeline repair and modification falls into two categories—planned work and emergency work. Emergency work usually results from some kind of incident, such as a leak, and often involves replacing a section of pipe or installing a repair sleeve. Planned work does not involve an incident, so there is ample time to study field conditions and organize work to control hazards.

This tab includes standards and procedures for repairing, replacing and relocating a pipeline.

NOTE: This tab does not provide general safety standards for pipeline repair and modification. For general safe work practices, refer to Book 2: Safety.

Legislation

CAN

Canada

National Energy Board (NEB):

- Onshore Pipeline Regulations, latest edition

USA

United States

Code of Federal Regulations:

- 49CFR – Part 195, Transportation of Hazardous Liquids by Pipeline

Related Standards

Corporate

Engineering Standards:

- D03-101, Pipeline Corrosion Assessment
- D04-102, Painting, Coating and Lining
- D06-101, Piping Design and Construction, Main Line
- D06-102, Piping Design, Station and Termi[illegible]

Industry

American National Standards Institute (ANSI):

- B31G, Manual for Determining the Remaining Strength of Corroded Pipelines
- B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

Very weak soils will require a piled foundation similar to that shown as an option in Figure 6.8: Typical Sectionalizing Valve Setting and Support. Piles may be designed as "skin friction" or "end bearing" in order to properly support the valve, depending on specific soil conditions.

Comment: When conditions of poor support exist, such as continuous or discontinuous permafrost, it may be prudent to monitor elevations at a valve site, when movement may be expected on a regular basis, to confirm the information assumed in the design. Any deviation from the anticipated pipe movements should be used as data for further analysis to verify integrity of the pipe and competency of the valve support system.

4.5 Launching and Receiving Trap Design

4.5.1 General

Company pipelines shall be configured to accommodate the passage of internal tools or pigs. Accordingly, each end of the pipeline section shall be equipped with a scraper trap, these being a launcher at the upstream end and a receiver downstream.

Comment: Main line bends should have a minimum radius of 6 diameters, to allow unhindered travel for internal inspection tools. For 48 in. traps, it is acceptable, if no other option is available, to have main line bends with a minimum radius of 3 diameters.

Traps may either be permanently installed or movable to allow temporary installation where there are no permanent pigging facilities. Typically, the Company's 1219 mm (48 in.) loops are configured with temporary traps during pig runs; refer to Figure 6.10: Typical 1219 mm (48 in.) Temporary Sending Trap Installation.

The spacing between traps shall not exceed 320 km (200 mi.).

Comment: Consideration should be given to reducing the length of the pipeline section between traps for looped lines to accommodate shorter runs and reduce the operational effort required to "gun barrel" the pipeline.

4.5.2 Trap Barrel Design

The trap barrel shall be designed in strict accordance with CSA-Z662, Clause 4.3.4 in Canada and ANSI/ASME B31.4, Part 2, in the USA. The closure shall be a quick opening, double bolt, yoke type, with horizontally opening hinges and be equipped with a positioning plate and an interlocking device, which will not allow opening of the closure until the barrel has been depressurized. The closure design shall be:

a. threaded yolk type;
b. double bolt, yoke type; or
c. bandlock closure.

Closures, which use wedge type retaining lugs, shall not be permitted.

Comment: Caution should be used to ensure the o-ring seal is not damaged during the opening/closing procedure for threaded type closures.

4.12.1 General Piping

Pipe flanges within stations and terminals should not be buried, unless approved by the Project Engineer. Buried valves should be weld-by-weld end configuration, and should be provided with access culverts, if required. The use of buried flange-by-flange valves should be minimized. All valve operators shall be accessible from grade or platforms.

Piping systems should be equipped with valved high point vents and valved low point drains. Connections for pressure devices shall be valved.

Above ground flanges or unions shall be provided, when necessary, within piping systems to permit removal of piping components and equipment.

Changes in direction of above grade rack piping shall also include a change in elevation.

The minimum pipe length between butt welds shall be one pipe diameter, or allowance shall be made for a standard pipe fitting.

Pipe crossings under major roadways in stations and terminals do not require pipe casings. Roadway crossings shall be at 90°, if possible.

4.12.2 Station Isolation Requirements

Station isolation valves are considered part of the main line piping; refer to Engineering Standard No. D06-101: Piping Design and Construction, Main Line. Station and terminal piping is located between inlet and outlet station isolation valves.

4.12.3 Scraper Traps

Scraper traps are considered part of the main pipeline system, but are generally located at stations and terminals. Drainage of all traps and thermal venting of LVP traps are directed to a station or terminal scraper trap sump tank. Free liquids shall be pumped into a truck. Scraper traps are normally operated in a flow-through operating mode. Therefore, actual thermal relieving is not normally expected; refer to Engineering Standard No. D07-301: Sump System Design.

Refer to Engineering Standard No. D06-101: Piping Design and Construction, Main Line, for details of scraper trap design and application.

4.12.4 Meter Manifold Piping

Meter manifolds are provided with inlet and outlet headers. Inlet piping to the upstream header and outlet piping from the outlet header shall be at opposite ends to provide a balanced flow through the meters; refer to Engineering Standard No. D09-101: Oil Measurement, Mechanical.

For turbine meters, the minimum requirement for straight piping should be 12 pipe diameters. Positive displacement meters do not require straight piping.

Block valves from the meters to the outlet group header and meter prover header shall be double block and bleed plug valves.

Basket strainers shall be located upstream of each meter run. Particulate removal design of basket strainers shall be based on requirements of the selected meter.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part

b) 195.214 Welding: General

(1) 195.214 (a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subject. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

The procedure did not provide clear direction requiring the quality of test welds used to qualify welding procedures to be determined by destructive welding.

(2) 195.214 (b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

The procedure did not provide specific direction on what welding procedure details and qualification tests results shall be recorded.

Purpose

The company qualifies welders to determine their ability to complete a weld according to company-approved welding procedure specifications (WPS).

Legislation

CAN

Canada

The Onshore Pipeline Regulations require that welding specifications, procedures, requirements and standards provide a level of safety at least equivalent to Z662-99, Oil and Gas Pipeline Systems.

For maintenance welds, Z662-99 allows the use of welding procedure specifications established and approved according to ANSI/ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications. However, unless otherwise stated, the standards of acceptability in ASME B31.3 are used to qualify welding procedures and welders for maintenance welding, because ASME B31.3 weld acceptance criteria are more similar to Z662-99 requirements than ASME Section IX requirements.

USA

United States

Title 49 of the Code of Federal Regulations, Part 195, Transportation of Hazardous Liquids by Pipeline requires that testing of welders and destructive testing of welding procedure specifications (WPS) complies with either of the following:

- API Standard 1104, Welding of Pipelines and Related Facilities
- ANSI/ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications

Weld acceptability, unless otherwise stated, is determined according to the standards in API 1104, Section 6.

Welder qualification is in accordance with API 1104 multiple qualification.

Purpose

Welding procedure specifications (WPS) include the details for various maintenance and repair welds on company facilities.

Scope

This appendix contains the data sheets for the following welding procedure specifications (WPS):

- WPS LB-32 (longitudinal butt weld)
- WPS DB-39 (downhill butt weld)
- WPS UB-40 (uphill butt weld)
- WPS LB-41 (longitudinal butt weld)
- WPS LB-42 (longitudinal butt weld)
- WPS DF-43 (downhill fillet weld)
- WPS UB-44 (uphill butt weld)
- WPS UB-45 (uphill butt weld)
- WPS UB-46 (uphill butt weld)
- WPS UB-47 (uphill butt weld)
- WPS DB-48 (downhill butt weld)
- WPS UF-56 (uphill fillet weld)

CAN

Canada

- WPS UF-49 (uphill fillet weld)
- WPS UN-50 (uphill nozzle weld)
- WPS UN-51 (uphill nozzle weld)
- WPS UF-53 (uphill fillet weld)
- WPS UN-55 (uphill nozzle weld)

USA

United States

- WPS UN-30 (uphill nozzle weld)
- WPS UB-36 (uphill butt weld)
- WPS UF-49 U.S. (uphill fillet weld)
- WPS UF-53 U.S. (uphill fillet weld)

Requirements

Qualification

Qualification of welding procedure specifications must be determined by destructive testing in accordance with either of the following:

- API Standard 1104, Welding of Pipelines and Related Facilities
- ANSI/ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications

Records

Retain original welding procedure specifications and qualification test results permanently in Pipeline Integrity.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part

c) 195.234 Welds: Nondestructive testing.

195.234 (b) Any nondestructive testing of welds must be performed--

(1) In accordance with a written set of procedures for nondestructive testing; and
(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

The procedure did not provide clear direction on specific procedures for non-destructive testing or clear direction about the process of operator approval for contractor non-destructive testing methods.

Requirements

All welds must be nondestructively inspected in accordance with Z662-99 (CAN), or API 1104, Section 6, 18th Edition (USA).

Use external contractors for the following tasks:

- magnetic particle inspection
- ultrasonic inspection (except for ultrasonic inspection performed to determine wall thickness)
- radiographic inspection

External contractors must submit a written procedure describing the nondestructive testing method that includes as a minimum:

- equipment used
- calibration of the equipment
- how to use the equipment

Qualification

Contractor personnel establishing procedures or techniques, scanning weldments or interpreting results must be qualified to Level II or Level III in accordance with CAN/CGSB Standard 48.9712-95, or ASNT Recommended Practice No. SNT-TC-1A.

Visual Inspection

Observe the welding process to ensure the weld is completed according to the qualified procedure.

Fillet Welds

If a circumferential fillet weld is subject to rapid cooling (e.g., on a liquid-filled lines or flowing gas line), examine the completed weld for undercut and cracks at the weld toe. Begin the inspection, starting with magnetic particle inspection (MPI), no less than 12 hr after welding:

- If there are no indications using MPI, the inspection is complete.
- If MPI shows indications, complete ultrasonic inspection on all suspected areas.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part

d) 195.266 Construction records.

A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility:

(a) The total number of girth welds and the number nondestructively testing, including the number rejected and the disposition of each rejected weld.
(b) The amount, location, and cover of each size of pipe installed.
(c) The location of each crossing of another pipeline.
(d) The location of each buried utility crossing.
(e) The location of each overhead crossing.
(f) The location of each valve and corrosion test station.

The procedure did not provide clear direction concerning recording the total number of girth welds and the number nondestructively tested, the number rejected and the disposition of each rejected weld.

NOTE: In Canada, ultrasonic inspection may be used as an alternative to radiographic inspection at the company's discretion.

Defects

Welds that exceed the defect acceptance criteria of Z662-99 (CAN) or API 1104 (USA) must be repaired or removed (see 02-02-07, Defect Repair).

Records

Nondestructive Testing Report

Record the results of ultrasonic and magnetic particle inspections on fillet welds using the Nondestructive Testing Report.

USA — Retain Nondestructive Testing Reports permanently in the [illegible] Activity Reporting database.

X-Ray Inspection of Girth Welds

Record the results of radiographic inspection of butt welds using the X-Ray Inspection of Girth Welds form.

USA — Retain X-Ray Inspection of Girth Welds forms permanently in the [illegible] Activity Reporting database.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

e) **195.306 Test Medium**

195.306 (b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if—

(1) The entire pipeline under test is outside of cities and other populated areas;
(2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;
(3) The test section is kept under surveillance by regular patrols during the test; and
(4) Continuous communication is maintained along the entire test section.

The procedure did not include the criteria for using crude oil as a pressure test medium.

Purpose

Selecting a test medium is influenced by ambient temperatures, pipe properties, availability of the test medium and whether the test section involves new or used pipe.

Requirements

Approved test media are water, air, or nitrogen. If any other test medium is used, Engineering must be involved to ensure adequate test preparation and safeguards.

Guidelines

Liquid Test Medium

Water

Domestic raw water (free of chlorine, etc.) is the preferred liquid test medium because it will not affect the equipment in the pipeline system and disposal is simple. Use water from natural sources only if the quality of water will not contaminate pump seals or valves.

Never use alkaline water as a test medium.

Crude Oil

Crude oil is not recommended as a test medium because it is compressible, flammable, and a liability if the pipe fails. Crude oil may be considered as a test medium if:

- it is low vapor pressure
- the pipe section under test is entirely outside of populated areas
- any building within 91 m (300 ft) of the test section remains unoccupied while the test pressure is ≥50% of SMYS
- the test section is continually patrolled during the test
- communication is maintained along the test section
- a contingency plan is developed to protect the environment in the event of a leak

Test Water Additives

Safety & Environment must approve all additives to test water before use. Avoid or minimize the use of additives, although non-toxic, biodegradable or photodegradable additives at minimum dosages may be permitted. Do not use additives such as sulphur hexafluride gas (SF6).

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

f) 195.308 Testing of tie-ins.

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

The procedure did not provide clear direction on whether tie-in pipe is to be tested with the section to be tied in or is to be tested separately.

Purpose

Industry standards and government regulations require that pipeline and other facilities are tested before commissioning to help ensure their integrity.

All piping, pipe assemblies, and individual components must be pressure tested before operation, either in a test section or pretested separately (e.g., pretested pipe for tie-ins or factory-tested components accompanied by test certification).

NOTE: When pretested pipe is used for a short tie-in to existing facilities, or when components such as Stopple tees and pipe fittings manufactured to ASME/ANSI standards are added after the pressure test, it is not necessary to pressure test the fittings and/or final weld(s). The number of fittings and welds not pressure tested must be minimized to the extent practicable, and such welds must be 100% nondestructively tested (see Book 4, Welding, 02-02-06, Inspection).

NOTE: For a definition of pretested pipe, see the Glossary.

Existing lines are sometimes retested, either to establish operating pressure to the full capability of the pipe or to demonstrate line integrity.

Scope

This tab identified the requirements for for conducting a pressure test, including planning, instrumentation, test practices, sample calculations, and documentation.

NOTE: A condensed specification is included in the Specifications for Station Construction given to contractors who fabricate and test piping for the pipeline system.

Legislation

CAN

Canada

National Energy Board (NEB):

- Onshore Pipeline Regulations, latest edition

natural gas liquids	a high vapor pressure, liquid hydrocarbon mixture that usually includes propane, iosbutane, normal butane, and condensate.
nondestructive inspection	the inspection of piping to reveal imperfections using radiographic, ultrasonic, magnetic particle techniques, or other methods that do not require disturbing, stressing or breaking of the materials.
nonmerchantable	refers to logs that are too small for timber harvesting.
nozzle reinforcement	an added reinforcement surrounding a nozzle which is designed to prevent distortion of the mainline piping or tank shell.
Operations employee	a generic term used to refer to all Operations employees.
Operations management	regional managers, team leaders and their designates.
organic matter	refers to decomposing leaves and branches on the surface of soils.
out-of-service	a pipeline or segment of a pipeline is out-of-service when it remains full of hydrocarbon, remains connected and is periodically put back into service (e.g., unused loops are put into service for pig runs).
ovality	the difference between maximum and minimum pipe diameters
pretested pipe	pipe tested in accordance with 07-02-03, Test Pressure and Duration, substantiated by documentation that the test met the standards in Tab 07, Pressure Testing.
protective system	a method of protecting employees from cave-ins, from material that could fall or roll from an excavation face or into an excavation, or from the collapse of adjacent structures. Protective systems include support systems, sloping and benching systems, shield systems and other systems that provide the necessary protection.
ramp	an inclined walking or working surface that is used to gain access to one point from another, and is constructed from earth or structural materials such as steel or wood.
reactivated	a deactivated pipeline or segment is reactivated when it is put back into service. Reactivation involves reconnecting, refilling and may involve a hydrostatic test if the pipeline or segment is deactivated for longer than 12 months.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

g) 195.310 Records

195.310 (b) The record required by paragraph (a) of this section must include:

195.310 (b) (9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The procedure did not include a requirement for providing a profile whenever there is a 100 ft elevation difference as part of the pressure test records.

NOTE: If the pressure test is the responsibility of a contractor as a part of a contract for construction, the test supervisor is responsible for the following activities:

- provide direct, continuous supervision
- witness all readings
- ensure test procedures comply with the necessary requirements
- ensure the pressure test is acceptable

Records

Test Documentation

Upon completion of the pressure test, the test supervisor:

- signs and dates all test documentation
- forwards original copies of the test documentation to Engineering

Test documentation includes:

- copy of the test section drawing
- original pressure chart(s) from recorders
- original pipe, soil and air temperature charts as required
- original Pressure Test Reports
- elevation profile over the entire length of the test section
- copy of calibration certificates (if not previously sent to Engineering)
- short written report that summarizes the test and includes general information, e.g., weather conditions, problems encountered, successes
- environmental permits and instructions (or reference to verbal approval) from the environment department, if required
- pressure-volume plot
- documentation of the cause, location and any repairs to a leak, rupture or other failure

Engineering retains all test documentation permanently.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

h) 195.403 Training.

1) 195.403 (b) At intervals not exceeding 15 months, but at least once each calendar year, the operator shall:

(a) 195.403 (b) (1) Review with personnel their performance in meeting the objective the training program set forth in paragraph (a) of this section;

The procedure did not provide clear direction that for emergency response training there shall be reviews of personnel performance once each calendar year not exceeding 15 months.

(b) 195.403 (b) (2) Make appropriate changes to the training program as necessary to ensure that it is effective.

The procedure did not provide clear direction concerning making appropriate changes to emergency response training as needed to insure that the training is effective.

2) 195.403 (c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the procedures established under 195.402 for which they are responsible to insure compliance.

The procedure did not provide clear direction concerning how supervisors maintain knowledge of the emergency response procedures for which supervisors are responsible.

Oil Spill Response

USA

Regional management is responsible to ensure oil spill response exercises comply with the National Preparedness for Response Exercise Program (PREP) Guidelines, triennial cycle requirements, including:

- tabletop exercises conducted annually

NOTE: One tabletop exercise every three years must (a) involve a worst case discharge scenario and (b) include the participation of any OSRO under contract with the company.

- equipment deployment exercises conducted annually
- unannounced exercises (either tabletop or equipment deployment) conducted annually
- unannounced exercises initiated by RSPA
- areas exercises initiated by the US Coast Guard, Environmental Protection Agency (EPA), or industry

NOTE: In the USA, during each triennial cycle, all 15 core components outlined in the PREP Guidelines must be exercised at least once. Credit may be taken for an actual spill response if the objectives were met, components of the response were evaluated and records were maintained.

USA

The Control Center is responsible to ensure internal notification exercises are conducted quarterly for qualified individuals (i.e., regional managers).

For information on the frequencies required for spill response tabletop exercises, deployment exercises, and water, land and ice exercises, see Book 2: Safety, 01-02-06, Safety Training.

First Hour Emergency Response

Storage tank locations, offices and terminals must hold annual evacuation drills to ensure:

- evacuation procedures are effective
- employees know assembly locations
- employees know fire emergency procedures
- emergency telephone numbers are correct

Regional management is responsible for:

- including fire emergencies (e.g., tank fires, fires at leak sites) in emergency response exercises whenever possible

- scheduling and conducting evacuation drills
- developing fire emergency response plans for each location (and establishing liaison with local fire departments and/or oil firefighting specialists)

Records

Record tank fire response training, NGL ignition training exercises and participation in emergency response exercises on course attendance sheets (CAN), or training record forms (USA), training evaluation forms, etc.

Records must include:

- date and time of training
- location of training (onsite or offsite)
- employee name
- names of participating external parties (e.g., fire department personnel)

Regional offices (CAN), or Safety & Environment (USA) must retain training records.

Oil Spill Response Exercises

Record oil spill response deployment exercises and track tabletop exercises using the Oil Spill Exercise Report database.

Retain reports permanently in the Oil Spill Exercise Report database.

Regional offices must retain all associated records for tabletop exercises.

USA — Retain records for the core components identified in the PREP Guidelines for 3 years in the Oil Spill Exercise Report database.

USA — Record training frequencies and participants for deployment and tabletop exercises using the Safety Training Tracking database.

USA — The Control Center must record internal notification exercises for qualified individuals. Retain internal notification exercises at the regional office.

Purpose

Post-emergency reviews, or "post mortems," are valuable learning tools following an emergency. Post-emergency reviews can prevent similar emergencies and identify:

- existing procedures needing modification
- new procedures needing implementation
- equipment needs
- training needs for emergency response personnel

Requirements

Frequency

Post-emergency reviews must be conducted for incidents that Operations management considers significant.

The detail and complexity of post-emergency reviews varies depending on the nature of the release.

NOTE: For information on government reporting requirements for incidents, see Book 1: General Reference, 02-02-02, Reporting.

Conduct post-emergency reviews as soon as practicable after the emergency has occurred and after relevant information is available.

Guidelines

Participants

At the discretion of Operations management, participants in the post-emergency review may include:

- key company employees involved with the emergency response, including control center and corporate office employees as relevant
- public officials
- government agencies
- contractors/consultants
- any other stakeholder identified by the Incident Commander

Topics

To encourage open, constructive post-emergency reviews, consider the following topics:

- overview (nature of the emergency, cause, complications)
- notification process

- incident reporting
- Incident Command System (ICS) implementation
- initial assessment and response
- site security
- containment and recovery
- sensitive areas; assessment, protection
- safety issues
- logistics
- communications
- documentation
- media/government relations
- landowner/right-of-way issues
- resources/equipment
- waste management
- site remediation
- training

Records

Post-emergency reviews must be documented and include a record of:

- participants
- effectiveness of emergency response procedures
- deficiencies and corrective action taken or planned.

Key findings resulting from post-emergency reviews must be shared across the company.

Requirements

Employees and contractors must participate in safety training as directed by the company (see Table 1 [CAN], Table 2 [EPSI] and Table 3 [USA]).

NOTE: Initial training for new or transferred employees is determined by the employee, safety coordinator and immediate supervisor, but must occur before the employee performs the work. Core training includes a complete course syllabus. Refresher training may or may not be as comprehensive as core training, and is provided periodically to update and maintain skills.

Safety training for employees within the same job classification depends on the work location. For example, in the USA, electrical/mechanical employees at an area without tankage may not need the tank fire response training required by employees within the same job classification at a terminal. Attendance is determined by local management.

First Aid Training
In addition to field employees, Enbridge Tower floor wardens and Duluth Office safety representatives must have formal first aid training and cardiopulmonary resuscitation (CPR) training (basic level).

Monitoring
Safety training must be monitored through:

- manual review questionnaires
- Supervisor's Safety Check Lists
- on-the-job evaluations
- emergency response exercises
- performance-based training (PBT) records

Safety training requirements are reviewed quarterly by regional Environmental Health & Safety (EH&S) committees.

Records

Safety training records are maintained in a computer database by safety coordinators.

Table 3
Safety Training—USA

Training	Frequency	Required By	Training Participants				
			Operations employees	PLM employees	Mechanical employees	Electrical employees	Field Office employees
asbestos awareness	annually[1]	29CFR 1910.1001	×	×	×	×	•
back care (USA)	3 yrs	company policy	×	×	×	×	•
bloodborne pathogens	annually[1]	29CFR 1910.1030	×	×	×	×	•
confined space entry	3 yrs	29CFR 1910.146	×	×	×	×	•
CPR – refresher	annually[1]	29CFR 1910.151	×	×	×	×	•
defensive driving – core	3 yrs	company policy	×	×	×	×	×
defensive driving – refresher	annually[1]						
electrical safety	2 yrs	29CFR 1910.332	×	×	×	×	•
	annually (electrical)						
ergonomics (USA)	2 yrs	OSHA (5) (a) (1)	•	•	•	•	•
excavation (USA)	3 yrs (core)	29CFR 1926.651	•	×	×	×	•
	annually (refresher)						
fall protection	3 yrs	1926.503	•	×	×	×	
fall protection – refresher	annually						
fire extinguisher maintenance (USA)	5 yrs	industry standard	•	•	•	•	
fire extinguisher training – NGL/crude ignition	annually[1] alternating	195.403 1910.157	×	[illegible]	×	[illegible]	•
first aid – standard level	3 yrs	1910.151	×	×	×	×	•

Table 3—*continued*
Safety Training—USA

Training	Frequency	Required By	Training Participants				
			Operations employees	PLM employees	Mechanical employees	Electrical employees	Field Office employees
forklift operations (USA)	3 yrs[1]	1910.178	•	×	•	•	
forklift – train the trainer certification (USA)	5 yrs	industry standard	•	•			
gas detector operation (USA)	annually[1]	1910.120 195.402	×	×	×	×	•
HAZCOM	annually[1]	1910.120	×	×	×	×	•
HAZMAT	3 yrs[1]	172.704	•	×	×	×	•
HAZWOPER	annually[1]	1910.120	×	×	×	×	•
hearing conservation (USA)	annually[1]	1910.95	×	×	×	×	•
hoisting/rigging	5 yrs	1910.184 1910.179	•	×	×	•	
ignition sources	annually[1]	195.402	×	×	×	×	•
incident command	3 yrs	1910.120	•	•			•
lockout procedures (USA)	annually	1910.147	×	×	×	×	
personal protective equipment	annually[1]	1910.132	×	×	×	×	•
radiation safety (USA)	2 yrs	NRC 10 Part 30.33				•	
respiratory fit testing – train the trainer	not required	1910.134	•	•	•	•	
respiratory protection – air purifying/supplied fit testing	annually	1910.134	×	×	×	×	•
safe work permits/hazard assessment (USA)	annually	1910.132	×	×	×	×	•

Table 3—*continued*
Safety Training—USA

Training	Frequency	Required By	Training Participants				
			Operations employees	PLM employees	Mechanical employees	Electrical employees	Field Office employees
safety representative training (USA)	annually	company policy	●	●	●	●	●
scaffolding – competent person	3 yrs (core)	1926.454	●	×	●	●	
	annually (refresher)						
spill response – deployment excrcise (land,water)	annually[1]	33 USC 1321	●	×	×	×	●
spill response – tabletop exercise	annually[1]	33 USC 1321	×	×	×	×	●
supervisory safety	5 yrs	1960.55		●	●	●	●
tank fire response (USA)	annually[1]	195.403	●	●	●	●	●
tank rescue (USA)	annually[1]	1910.146	●	●	●	●	
tank rescue – train the trainer certification	5 yrs	industry standard	●	●	●	●	

NOTES

1 frequency determined by regulation/standard

LEGEND

- ● attendance determined by regional/department management
- × attendance mandatory

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

i) 195.404 Maps and Records

195.404 (b) Each operator shall maintain for at least 3 years daily operating records that indicate—

195.404 (b) (2) Any emergency or abnormal operation to which the procedures under 195.402 apply.

The procedure is inadequate because Table 3 of Enbridge's Pipeline Operations Records has not been revised to include abnormal operation records that are recorded using FACMAN software.

Table 3—*continued*
Pipeline Operations Records

Record	When	Responsibility	Distribution	Retention Location	Retention Period	Reference
pressure relief valves (USA)	annually (crude)	mechanical technician		Maximo	2 years	MP251; MP290 (pressure control valve system)
	semiannually (NGL)					MP255
	every 5 years (NGL storage tanks)	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	permanently	Book 3: Pipeline Facilities, 09-02-02, Tank Inspections
station pressure devices (USA)	semiannually	electrical technician		Maximo	2 years	EP224 (pressure control valves); EP268 (pressure transmitters); EP269 (pressure switches); ET313 (pressure allowable setpoints)
line pressure control charts or zip disk/video recorder (USA)	twice per week (charts), or annually (zip disk)	electrical technician		Maximo	permanently	OP245
abnormal operating condition	after notification of abnormal operating condition	control centre operator		FACMAN; Maximo (if equipment related); SCADA Trouble Report (if SCADA related)	permanently	Edmonton Control Center Procedures

ENBRIDGE

Abnormal Operating Conditions - Reporting Requirements

Once an Abnormal Operating Condition has been identified:

1. Notify the Control Centre Coordinator.
2. Record the abnormal condition in FACMAN.
3. If the source of the abnormal condition is equipment related:
   - Contact maintenance on Call support if the condition requires immediate support.
   - Create a MAXIMO work order if the condition does not require immediate support.
4. If the source of the abnormal condition is SCADA related:
   - Contact SCADA support if the condition requires immediate support.
   - Create a SCADA trouble report if the condition can be delayed until following business day.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

j) 195.410 Line Markers

195.410 (a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

a) 195.410 (a) (1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

The procedure did not provide clear direction concerning what other line marker locations are sufficient to accurately locate the line.

b) 195.410 (c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.

The procedure did not provide clear direction concerning line markers in aboveground areas accessible to the public.

Requirements

Warning Signs

Signs indicating the presence of each pipeline on the right-of-way (ROW) (i.e., one sign for each pipeline) must be located:

- at road, railway, and water crossings on each side of the crossing
- in areas of population growth and/or construction activity at sufficient intervals to clearly identify the pipeline location
- in areas that are accessible to the public where the pipeline is above grade (e.g., risers, valves)

CAN

ROW signs must display the:

- words "High Pressure Petroleum Pipeline"
- company name
- 24-hour emergency telephone number
- commodity being transported

USA

ROW signs must display the:

- words "Warning Petroleum Pipeline"
- company name
- 24-hour emergency telephone number

ROW signs may also display (a) the milepost or kilometrepost and (b) the pipe depth (on the back of the sign or on the signpost)

NOTE: The words "depth of cover" should not be written on the sign; instead, enclose the dimension in brackets, e.g., (1200 mm)

ROW signs must be constructed in accordance with the Enbridge Graphic Standards, and with the Enbridge Rebranding Book and Purchasing Specifications (USA).

Where the ROW has more than one line, affix a 3-in. reflective color-coded disc (corresponding to the color of the pipeline) to each signpost directly beneath the sign.

Orient ROW signs perpendicular to the ROW, located on one side of the line but not directly over the line, indicating the approximate pipeline location.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

k) 195.412 Inspection of rights-of-way and crossings under navigable waters.

a) 195.412 (a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.

The procedure is inadequate because it restricts follow up on items found during right-of-way inspections to only items that Enbridge considers "significant" and it does not make clear that follow up action, if needed, must be for all items requiring inspection under the regulations and not just what Enbridge considers "significant."

Purpose

The company's right-of-way (ROW) is regularly inspected to:

- maintain safe operations and good public relations
- ensure the integrity of the pipeline is protected from external damage resulting from unauthorized work by others
- ensure the ROW is safe for agricultural or urban activity, and is properly marked

Requirements

Aerial Patrols

Conduct aerial inspections of the entire ROW and the land adjacent to the ROW for abnormal surface conditions at intervals not exceeding 3 weeks (21 days), but a minimum of 26 times per calendar year.

ENB (NW)

Conduct aerial inspections of the entire ROW and the land adjacent to the ROW for abnormal surface conditions once per week.

Abnormal surface conditions include:

- visible crude oil and/or vapor clouds
- indications of oil or gas leaks
- excavation or dredging
- unauthorized activities
- unauthorized heavy equipment
- encroachment
- construction activities
- debris (e.g., dumping)
- seismic activity
- forestry operations
- exposed or floating pipe
- withering vegetation
- soil defects (e.g., slides, erosion, sunken backfill, cave-ins or other surface disturbances)
- ice effects
- water crossings and flooding
- damage to company property
- missing or moved aerial markers, line markers or identification signs

The patrol pilot should be made aware (via Lotus Notes or telephone) of any significant activity on the pipeline system.

Any abnormal surface condition or activity observed by the pilot must be immediately reported by radio to the closest attended location or, if unable to make contact, by telephone to the Control Center.

ENB (NW)

Any abnormal surface condition or activity observed by company employees aboard the aircraft must be immediately investigated.

PLM coordinators/supervisors are responsible for investigation and remediation of abnormal conditions or activities reported.

CAN

Ground Patrols

The regional manager is responsible to ensure ground inspections of the ROW in densely populated areas occur at regular intervals.

Ground patrol workers must immediately report abnormal conditions or, if the pipeline is at risk, must take appropriate action along the ROW.

CAN

PLM Inspections

In addition to routine patrols, at least every 2 years PLM must inspect the ROW, focusing on conditions that include:

- erosion, subsidence or other ground disturbances
- deterioration of company facilities (e.g., signage, fencing, crossings, casing vents or painted fence posts)
- overgrowth of vegetation
- encroachment
- debris
- disturbances of crossings (below grade, surface and aerial)
- unauthorized activity having the potential for ground disturbance (e.g., construction activities, seismic or forestry operations, mining or other excavating activities)
- indications of oil or gas leaks
- exposed or floating pipe

Use the most effective method for the situation to inspect the ROW (e.g., walking, driving, aerial observations).

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

k) 195.412 Inspection of rights-of-way and crossings under navigable waters.

b) 195.412 (b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

The procedure did not provide clear direction concerning what specific crossing components are to be inspected during a waterway inspection.

NOTE: For assistance in conducting risk assessments, contact Operations Services.

Underwater Inspections

CAN

Conduct surface and underwater inspections of pipeline crossings periodically.

USA

Commercially Navigable Water Crossings

Inspect the condition of each pipeline crossing under a commercially navigable waterway (including any abandoned pipeline that crosses over, under or through a commercially navigable waterway) [illegible] exceeding 5 years (see Table 1). Report any of the following adverse conditions observed during underwater inspections to Engineering [illegible] possible (preferably within 24 hrs):

- **spanning pipelines**
- **significant debris around or in contact with the pipe[illegible]**
- **pipe coating in poor condition**
- **sand abrasion [illegible]**
- **dents**
- **oblongations**
- **gouges**
- **any other condition that could affect the [illegible] of the pipeline crossing (e.g., scouring of the river bottom, [illegible] of river banks)**

Navigable water crossings must be inspected by qualified underwater inspection contractors under direction from Engineering. Inspection methods may include (a) manned inspections by qualfied divers, or (b) remotely operated vehicle (ROV) inspections by qualified technicians. Sonar imaging systems also may be used to supplement ROV inspections.

Observed anomalies must be reported to Engineering within 24 hrs.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

l) 195.420 Valve Maintenance

195.420 (a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

The procedure did not provide clear direction concerning maintaining all valves necessary for the safe operation of the operator's pipeline system.

Table 3—*continued*
Pipeline Operations Records

Record	When	Responsibility	Distribution	Retention Location	Retention Period	Reference
Tank In-Service Inspection Report	after formal in-service inspection of atmospheric crude oil tank every 5 years minimum	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	until the next inspection	Book 3: Pipeline Facilities, 09-02-02, Tank Inspections
Tank Out-of-Service Inspection Report	after formal out-of-service inspection of atmospheric crude oil tank every 20 years minimum	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	until the next inspection	Book 3: Pipeline Facilities, 09-02-02, Tank Inspections
Pipeline Hydrotest Permit Request	10 weeks (CAN) or 26 weeks (USA) before the pressure test	test supervisor		Safety & Environment	permanently	Book 3: Pipeline Facilities, 07-02-01, Test Planning & Preparation
Pressure Test Report	after pressure testing	test supervisor	Engineering	Engineering	permanently	Book 3: Pipeline Facilities, 07-02-05, Hydrostatic Pressure Test
construction records, maps and drawings (USA)	as required after a facility is changed	PLM supervisor/ coordinator	regional office; onsite	Construction Project Management database; As-Built Tracking database	permanently	Engineering Drafting
valve operation, inspection and maintenance (USA)	semiannually	mechanical technician		Maximo	permanently	MP107; MP256
	annually					MP320; MP330; MP179

ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM
JOB PLAN

Plan: MP107
scription: Valve Operators - Semi-annual

Lead Craft:
WO Priority: 3
Downtime: Y
Interruptable: N
Duration: 0.5

Op	Description	Hours
1	1. Visually inspect lubricant for condensation, metallic particles or any contamination.	0
2	2. Check gearcase lubricant level.	0
3	3. Grease upper bearing.	0
4	4. Flush and change oil as required.	0
5	5. Lubricate valve stem (if applicable).	0
6	6. Cycle valve under power for its full travel if possible listening for unusual noise.	0
7	7. Record service and comments in equipment record.	0
8	CROSS REFERENCE: Refer to Limitorque Manuals for proper lubricant specifications.	0
9	Refer to EIM Installation and Maintenance Manual.	0
10	Time to complete Job Plan	0.5

dified By: **Modified Date:**

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ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM
JOB PLAN

Plan:	MP256
scription:	Valves, OQT - Semi-annual (DOT)
Lead Craft:	
WO Priority:	3
Downtime:	Y
Interruptable:	N
Duration:	0.5

Op	Description	Hours
1	GATE VALVE SERVICING:	0
2	1. Service valve in open position if possible.	0
3	2. Remove stem protector and check stem threads for proper lubrication.	0
4	3. Clean and lube as necessary.	0
5	4. Check for water or crude oil in valve yoke and drain.	0
6	5. Determine extent of leakage of valve stem seals, take appropriate action if crude oil is found.	0
7	6. Add antifreeze to valve yoke.	0
8	7. Tighten stem packing on valves with adjustable packing if necessary (Darling & Crane Valve)	0
9	8. If necessary, de-assign the valve with the appropiate control center and/or disable PLC logic	0
10	9. Unlock, de-clutch, and hand crank electric valves partially to verify operation.	0
11	10. Unlock and operate hand valves partially to check operation.	0
12	11. Return valve to proper position, apply locks.	0
13	12. Verify correct position status with control center if applicable.	0
14	13. Have valve re-assigned and/or enable PLC logic for valve.	0
	14. Submit completed inspection form to District Office.	0
	CROSS REFERENCE:	0
17	1. WKM valve manual for stem packing adjustments.	0
18	2. M&J valve manual.	0
19	PLUG VALVE SERVICING:	0
20	1. Inspect valve for leakage	0
21	2. Tighten stem injection packing if valve stem is leaking.	0
22	3. Add more packing using sealweld slick sticks if necessary.	0
23	4. Maintain periodically by injecting sealant with high pressure grease gun into body injection	0
24	button (usally on top of valve).	0
25	NOTES:	0
26	1. Grease valve more frequently if it is used often.	0
27	CROSS REFERENCE:	0
28	1. Sealweld valve maintenance manual.	0
29	2. Rockwell Nordstrom plug valve manual.	0
30	Time to complete Job Plan	0.5

dified By: **Modified Date:**

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ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM
JOB PLAN

Plan: MP320
scription: Valve Operators- Annual

Lead Craft:
WO Priority: 3
Downtime: Y
Interruptable: N
Duration: 0.5

Op	Description	Hours
1	1. Visually inspect lubricant for condensation, metallic particles or any contamination.	0
2	2. Check gearcase lubricant level.	0
3	3 .Grease upper bearing. (if applicable)	0
4	4. Flush and change oil as required.	0
5	5. Lubricate valve stem.	0
6	6. Cycle valve under power for its full travel if possible listening for unusual noise.	0
7	7. Record service and comments in equipment record.	0
8	CROSS REFERENCE: Refer to Limitorque Manuals for porper lubricant specifications.	0
9	Refer to EIM Installation and Maintenance Manual.	0
10	Time to complete Job Plan	0.5

dified By: **Modified Date:**

25-MAR-2003 09:06 **ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM**
JPPRINT.SQT **JOB PLAN**

Plan: MP320
cription: Valve Operators- Annual

Lead Craft:
WO Priority: 3
Downtime: Y
Interruptable: N
Duration: 0.5

Op	Description	Hours
1	1. Visually inspect lubricant for condensation, metallic particles or any contamination.	0
2	2. Check gearcase lubricant level.	0
3	3 .Grease upper bearing. (if applicable)	0
4	4. Flush and change oil as required.	0
5	5. Lubricate valve stem.	0
6	6. Cycle valve under power for its full travel if possible listening for unusual noise.	0
7	7. Record service and comments in equipment record.	0
8	CROSS REFERENCE: Refer to Limitorque Manuals for porper lubricant specifications.	0
9	Refer to EIM Installation and Maintenance Manual.	0
10	Time to complete Job Plan	0.5

dified By: **Modified Date:**

25-MAR-2003 09:07 ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM
JPPRINT.SQT JOB PLAN

Plan: MP330
cription: Valve Operators - Service Hyd. Operator - Annually

Lead Craft:
WO Priority: 2
Downtime: Y
Interruptable: N
Duration: 1

Op	Description	Hours
1	1. Take out of service.	0
2	2. Lock or secure valve in proper position.	0
3	3. Drain oil and change filter (Analyze and change as needed).	0
4	4. Clean or w ipe out tank if possible.	0
5	5. Fill w ith oil.	0
6	6. Open valves on riser.	0
7	7. Bleed off air.	0
8	8. Return to service.	0
9	NOTES:	0
10	1. Close valves on riser only if line is running.	0
11	2. Grease fittings as necessary.	0
12	Time to complete Job Plan	1

dified By: Modified Date:

25-MAR-2003 09:11
JPPRINT.SQT

ENBRIDGE MAINTENANCE MANAGEMENT SYSTEM
JOB PLAN

Plan: MP179
cription: OQT - Valve Servicing - Annual

Lead Craft:
WO Priority: 2
Downtime: Y
Interruptable: N
Duration: 0.5

Op	Description	Hours
1	1. Check stem seals for leakage.	0
2	2. Inject sealant to assist seat rings if valve isn't sealing properly.	0
3	GATE VALVE SERVICING:	0
4	1. Service valve in open position if possible.	0
5	2. Remove stem protector and check stem threads for proper lubrication.	0
6	3. Clean and lube as nesessary.	0
7	4. Check for water or crude oil in valve yoke and drain.	0
8	5. Determine extent of leakage of valve stem seals, take appropriate action if crude oil is found.	0
9	6. Add antifreeze to valve yoke.	0
10	7. Tighten stem packing on valves with adjustable packing if necessary (Darling & Crane valve).	0
11	8. Operate valve partially or fully to check operation if possible.	0
12	9. Return valve to proper postion.	0
13	CROSS REFERENCE: WKM valve manual for stem packing adjustments. M&J Valve Manual	0
14	PLUG VALVE SERVICING:	0
	1. Inspect valve for leakage.	0
	2. Tighten stem injector packing if valve stem is leaking.	0
17	3. Add more packing using sealweld slick sticks if necessary.	0
18	4. Maintain periodically by injecting sealant with pressure grease gun into body injection button	0
19	(usally on top valve).	0
20	NOTES: Grease valve more freguently if it is used often.	0
21	CROSS REFERENCE: Sealweld valve maintenance manual. Rockwell Nordstrom Plug Valve	0
22	manual.	0
23	Time to complete Job Plan	0.5

dified By: **Modified Date:**

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

m) 195.422 Pipeline repairs.

195.422 (b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

The procedure did not include an overview statement that replacement components shall be designed and have a maximum operating pressure compatible with existing facilities. Additionally, the procedure did not reference company Engineering Standards.

Purpose

Standards for pipeline repairs and modifications minimize the risk of injury to workers and the public, and help to protect the environment.

Requirements

Planning and Preparation

For information on planning and preparing for maintenance activities, see Tab 01, Planning and Preparation.

Notification

Planned pipeline repair and modification work must be organized and scheduled under authority of the regional manager or designate (see 01-02-02, Notification).

Pressure Limitations

For working pressures for pipeline repair, see 06-04-01, Maximum Pressures for Maintenance Activities.

Excavations

For information on excavating a damaged pipeline, see Tab 04, Trenching and Excavations.

When excavating mainline pipeline below pipe bottom, the pipe must be adequately supported.

CAN

For sleeve support and backfill details, see Engineering Drawing No. D-1.7-2039-3-0.

Replacement Components

All replacement components must meet design and maximum operating pressure (MOP) compatibility with pipe design specifications in accordance with Engineering Standard [illegible]6-102, Piping Design, Station and Terminal.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

n) 195.428 Overpressure safety devices

195.428 (d) After October2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

The procedure is inadequate because the tank internal inspection table included in the O&M manual did not include the testing of overfill protection systems on breakout tanks, including the NGL breakout tanks.

NOTE: For more information, see the Routine In-Service Tank Inspection Report in the Tank Management database, or the applicable Maximo Job Plan.

In addition to visual inspections, check the operability of high tank alarm systems monthly (see Book 5: Petroleum Quality & Measurement, 05-03-03, Checking High Tank Alarm Systems).

Annual Inspections
Visually inspect each aboveground storage tank annually for:

- condition of platforms and ladders
- condition of roof legs, manholes, vents, drains
- leaks in pontoons
- condition of seals
- condition of rescue tank davit

Take seal gap measurements as required.

NOTE: For more information, see the Annual Tank Inspection Report in the Tank Management database, or the applicable Maximo Job Plan.

Formal Inspections
Complete formal inspections of atmospheric aboveground storage tanks in accordance with the schedule in the Tank Management database, or with the applicable Maximo Job Plan.

Regions are responsible for scheduling and preparing tanks for formal inspections.

Pressurized Tanks

Pressurized tanks must be inspected in accordance with API 510, Inspection and Testing of Pressure Vessels and Pressure Relief Devices (see Table 2), including:

- Section 6.2, External Inspection
- Section 6.3, Internal and On-Stream Inspection
- Section 6.5, Pressure-Relief Devices

Table 2
Summary of Pressurized Tank Inspections

Type	Frequency	Who
Pressure Relief Devices	5 years[1]	contract inspector[2]
External	5 years	employee[2] or contract inspector[2]
Internal	10 years[1,3]	employee[2] or contract inspector[2]

NOTES:
1. More frequent inspections may be required due to corrosion growth rates or inspection results.
2. Certified to API 510, Appendix B.
3. Frequency is based on "actual service exposed life."

Responsibilities

Corrective Action

Site supervisors are responsible for reviewing routine and annual atmospheric tank inspection reports, and for:

- evaluating the need for repairs
- initiating and monitoring repairs
- consulting with the regional engineer, contract inspector and Operations Services for unusual or major repairs
- ensuring completed repairs are documented

NOTE: Major repairs include re-leveling a tank, welding within the floor-to-shell critical zone, or any work requiring a hydrotest.

Site supervisors and regional engineers are responsible for reviewing atmospheric and pressurized tank inspection reports from contract inspectors, and for :

- evaluating the recommendations
- initiating and monitoring repairs
- consulting with Operations Services for unusual or major repairs
- ensuring repairs are completed or exceptions to the recommendations are documented

Records

Record inspections on the Routine In-Service Inspection Report or the Annual Tank Inspection Report, or in the applicable Maximo Job Plan, and retain the original onsite for 2 years.

Formal inspection reports completed by contract inspectors must include:

- completed API checklist, if applicable

Table 3—*continued*
Pipeline Operations Records

Record	When	Responsibility	Distribution	Retention Location	Retention Period	Reference
pressure relief valves (USA)	annually (crude)	mechanical technician		Maximo	2 years	MP251; MP290 (pressure control valve system)
	semiannually (NGL)					MP255
	every 5 years (NGL storage tanks)	regional engineer; terminal supervisor	regional office; Operations Services	onsite (original); regional office (copy); Operations Services (copy)	permanently	Book 3: Pipeline Facilities, 09-02-02—Tank Inspections
station pressure devices (USA)	semiannually	electrical technician		Maximo	2 years	EP224 (pressure control valves); EP268 (pressure transmitters); EP269 (pressure switches); ET313 (pressure allowable setpoints)
line pressure control charts or zip disk/video recorder (USA)	twice per week (charts), or annually (zip disk)	electrical technician		Maximo	permanently	OP245
Facman	any abnormal operation			Edmonton Control Center Procedures, Maximo	permanently	

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

o) 195.555 What are the qualifications for supervisors?

You must required and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402 (c) (3) for which they are responsible for insuring compliance.

The procedure did not provide clear direction concerning corrosion control supervisors must maintain knowledge of that portion of the corrosion control procedures for which the supervisors are responsible.

Purpose

This standard identifies the responsibilites and requirements for monitoring the cathodic protection system to ensure the equipment is functioning properly.

Responsibilities

Corrosion Technician

Regional corrosion technicians are responsible for ensuring:

- adjustive surveys
- rectifier readings
- critical bond readings
- electrical isolation checks
- repairs and upgrades to cathodic protection systems
- installation of new cathodic protection systems

NOTE: For information on installing new cathodic protection equipment, see Engineering Standard D04-101, Cathodic Protection.

In addition, regional corrosion technicians are resonsible for:

- monitoring company/adjacent utilities to ensure current interference testing if the cathodic protection system of an adjoining utility changes
- developing remediation strategies, including critical bonds, to minimize adverse effects on company/adjacent structures if interference tests detect deleterious current interference

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NOTE: Regional corrosion technicians keep informed of changes to cathodic protection systems by participating in corrosion control committees in the region (e.g., NACE, SOCE).

USA
- conducting cathodic protection studies and facilitating research

USA
- maintaining historical cathodic protection information

USA
- completing corrosion technician performance-based training (PBT), and achieving NACE CP Level 1 Certification within 1 year of employment

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

t) 195.579 What must I do to mitigate internal corrosion?

195.579 (c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

The procedure did not provide clear direction concerning checking adjacent pipe when internal corrosion is found.

NOTE: The following areas are prone to deterioration; therefore, direct particular attention to the pipe condition:

- at grade level
- in the transition area between the painted pipe and the underground coating (e.g., poly tape, coal tar, polyurethane)
- under thermal insulation and disbonded coatings
- at pipe supports
- in splash zones

Immediately report significant damage or deterioration to above ground pipe and equipment to the site supervisor.

Record annual inspections and actions taken to protect above ground pipe from corrosion, including painting, recoating, repairs or replacement, using the Corrosion Inspection Report (USA) or in regional office files (CAN).

Hydrogen Foils

Manual hydrogen foil readings must be taken at least 10 times per year with intervals not exceeding 6 weeks; however, make every effort to take readings once per month.

NOTE: During cleaning and/or inhibitor injections, Pipeline Integrity may increase the frequency of hydrogen foil readings.

Investigation and Repair

All anomalies, internal and external, must be evaluated and repaired, if required, in accordance with 06-02-02, Defect Evaluation and Repair Methods.

Corrosion anomalies must be assessed and the most serious anomalies addressed first. Field measurements must be compared to tool data, and adjustments made to the excavation program if necessary.

Visually inspect any pipe or fittings removed from the line for evidence of internal corrosion, and record the results using the Pipeline Integrity Field Report (CAN) or the Corrosion Inspection Report (USA).

If internal corrosion exceeds tolerable limits, evaluate unexposed pipe in the vicinity of the corrosion in accordance with Engineering Standard D03-101, Pipeline Corrosion Assessment, and Tab 06, Pipe Repair and Modification, following the next internal inspection.

Records

Pipeline Integrity Field Report/Corrosion Inspection Report

Record both "as found" and "as left" conditions of exposed mainline or station piping during excavations using the Pipeline Integrity Field Report (CAN), or the Corrosion Inspection Report (USA). Reports must include:

- exact location (milepost or kilometrepost)
- condition of the coating
- cathodic protection status
- corrosion type and severity
- type of repair
- potential readings at the pipe-to-soil interface
- results of any stress corrosion cracking (SCC) investigations
- comments/observations
- sketch of anomalies being assessed

CAN

After excavating for corrosion or crack investigation, record the results using the Pipeline Integrity Field Report, including:

- soil and landscape information
- soil sampling and analysis
- corrosion deposits/coating condition

CAN

Retain Pipeline Integrity Field Reports as follows:

- permanently in Pipeline Integrity
- copy at the regional office

USA

Retain Corrosion Inspection Reports as follows:

- permanently in the PLM Activity Reporting database
- copy at the regional office for 5 years
- copy in Engineering

Hydrogen Foil Readings

Record manual hydrogen foils readings using the Hydrogen Foil Activity Report.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

u) 195.589 What corrosion control information do I have to maintain?

195.589 (a) You must maintain current records or maps to show the location of—

(1) Cathodically protected pipelines;
(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and
(3) Neighboring structures bonded to cathodic protection systems.

195.589 (b) 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.

195.589 (c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573 (a) and (b), and 195.579 (b) (3) and (c) must be retained for as long as the pipeline remains in service.

(1) The procedure did not provide clear direction concerning the criteria for record retention periods for corrosion control information.

(2) The procedure did not provide clear direction concerning documenting all inspections performed under 195.583, even when no corrective action is needed.

CAN

Retain Monthly Rectifier Reports as follows:

- original onsite permanently
- copy at the regional office permanently
- copy in Pipeline Integrity permanently

USA

Retain Monthly Rectifier Reports as follows:

- original in the Corrosion database permanently
- copy at the regional office for 3 years

Annual Cathodic Protection Potential Survey

Annual Cathodic Protection Potential Survey reports must include:

- pipe-to-soil potential and line current readings at all accessible mainline test lead locations and at above grade appurtenances indicated on the Test Point Feature List (available from the regional corrosion technician)
- pipe-to-soil potential readings at station and terminal locations and the above grade facilities indicated on the station drawings
- condition of rectifier and ground bed including checked and calibrated rectifier output
- record of DC current flow, current drain and the potential of each pipeline adjacent to the rectifier, where monitoring is possible
- description of minor repairs and adjustments to the cathodic protection system
- list of any damaged, missing or nonfunctioning test stations (when tested according to NACE Standard RP0169-2002, Control of External Corrosion on Underground or Submerged Metallic Piping Systems)
- recommendations for repairs, replacements or expansions required for the rectifiers or ground beds

Retain Annual Cathodic Protection Potential Survey reports as follows:

- original at the regional office for 5 years
- copy in Pipeline Integrity permanently

If internal corrosion exceeds tolerable limits, evaluate unexposed pipe in the vicinity of the corrosion in accordance with Engineering Standard D03-101, Pipeline Corrosion Assessment, and Tab 06, Pipe Repair and Modification, following the next internal inspection.

Records

Pipeline Integrity Field Report/Corrosion Inspection Report

Record both "as found" and "as left" conditions of exposed mainline or station piping during excavations using the Pipeline Integrity Field Report (CAN) or the Corrosion Inspection Report (USA). Reports must include:

- exact location (milepost or kilometrepost)
- condition of the coating
- cathodic protection status
- corrosion type and severity
- type of repair
- potential readings at the pipe-to-soil interface
- results of any stress corrosion cracking (SCC) investigations
- comments/observations
- sketch of anomalies being assessed

CAN

After excavating for corrosion or crack investigation, record the results using the Pipeline Integrity Field Report, including:

- soil and landscape information
- soil sampling and analysis
- corrosion deposits/coating condition

CAN

Retain Pipeline Integrity Field Reports as follows:

- permanently in Pipeline Integrity
- copy at the regional office

USA

Retain Corrosion Inspection Reports as follows:

- permanently in the PLM Activity Reporting database
- copy at the regional office for 5 years
- copy in Engineering

Hydrogen Foil Readings

Record manual hydrogen foil readings using the Hydrogen Foil Activity form.

B. Maintenance and Normal Operations Items.

5. 195.402 (c) (5) Analyzing pipeline accidents to determine their causes.

The procedure did not provide clear direction concerning analyzing accidents to determine their causes.

6. 195.402 (c) (6) Minimizing the potential for hazards identified under paragraph (c) (4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c) (5) of this section.

The procedure did not provide clear direction concerning minimizing the potential for hazards and minimizing the possibility of recurrence of accidents.

Purpose

Incident investigation is a systematic process for determining the root causes of incidents based on facts, and implementing controls to prevent similar events from occurring.

Benefits to incident investigation include:

- prevent other incidents
- identify all causes
- recommend corrective action alternatives
- identify trends and problem areas
- provide statistical data
- create permanent records
- meet regulatory requirements

Scope

This standard applies to unforeseen or unplanned occurrences that result in any incident.

Equipment

Typical incident investigation materials include:

- tape measure
- camera
- appropriate personal protective equipment (PPE)
- notepad and pen or pencil
- flashlight

Requirements

All incidents require an investigation. The extent of the investigation is determined by the lead investigator and depends on the severity of the incident. In addition, incidents that have a high potential for reoccurrence require a thorough and complete causal analysis, although any incident may result in a detailed investigation.

Incident investigation must answer the 5 W's (i.e., who, what, when, where and why).

Training

All supervisors must receive training in incident investigation techniques (see Book 2: Safety, 01-02-06, Safety Training).

NOTE: For more information on classifying incidents, see the Safety & Environment Intranet site.

Safety Representatives

Safety representatives are responsible for (a) participating in the investigation where practical, and for (b) assisting in ensuring follow-up is completed.

Guidelines

Preparation

Decide who will respond.

Gather investigation materials.

Review documentation that may help determine what to look for at the scene (e.g., training records, operating procedures, inspection records, maintenance records, previous incident reports).

Visit the Scene

Minimize further risk.

Ensure injured are cared for.

Isolate the investigation scene.

Become oriented with the circumstances.

Identify the people involved.

Prevent evidence from being removed or moved.

Gather Evidence

Take measurements, photos, and samples.

Note positions of controls, switches.

Identify tools, materials and equipment involved.

Review all sources of information.

Talk to outside resources if necessary.

Attach diagrams and photos.

Implementation and Follow-up
Have recommendations been implemented?

Have similar accidents recurred?

Are workers comfortable with changes?

Have any new problems been created?

B. Maintenance and Normal Operations Items.

7. 195.402 (c) (10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with 195.59 of this part.

The procedure did not provide clear direction concerning filing reports under 195.59.

CAN

The inert gas fill in a deactivated pipeline or pipeline segment must remain intact. Positive pressure greater than 70 kPag (10 psig) must be maintained (see Engineering Standard D06-101, Piping Design and Construction Main Line). Take pressure readings at least once each year and document readings in a continuing record.

NOTE: If the pressure of the inert gas drops below 70 kPag, the monitoring frequency should be increased. Develop a plan to investigate possible leaks and to repressurize the line.

Abandoned Pipelines

CAN

Abandoned pipelines or sections of pipeline may be left in place to deteriorate naturally, if allowed by regulations, or may be physically removed from the ground and salvaged.

USA

Abandoned pipelines or sections of pipeline must be totally separated from possible service and may be either abandoned in place, if permitted, or removed from the ground in an environmentally acceptable manner.

USA

Notify Engineering within 48 hrs after abandonment of a pipeline that crosses over, under, or through a commercially navigable waterway.

NOTE: For more information on inspecting abandoned underwater pipelines, see 03-02-01, ROW Inspections.

Reactivated Pipelines

Deactivated pipelines must be internally inspected before reactivation. When the condition of the pipeline cannot be satisfactorily assessed, a hydrotest to requalify the pipeline for a desired MOP may be required.

CAN

Reactivation of pipelines that have been out of service for 12 months or more requires an NEB application and approval before starting activation work (see Engineering Standard D06-101, Piping Design and Construction Main Line).

Records

USA

Abandoned Underwater Report

After abandonment of an underwater pipeline, Engineering must submit a report to the National Pipeline Mapping System (NPMS) or to the Department of Transportation (DOT) that includes at a minimum (a) the date, location, size, and method of abandonment, and (b) a certificate that the pipeline was abandoned in accordance with applicable laws.

NOTE: For more information on reporting requirements see CFR49, Subpart B, 195.59.

Retain abandoned underwater reports as follows:

- original in Engineering for 5–10 years after the pipeline is deactivated
- copy in Compliance & Risk Management
- copy at the regional office

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

p) 195.569 Do I have to examine exposed portions of buried pipelines.

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

The procedure did not provide clear direction concerning examining all exposed pipe whenever the operator has knowledge of exposed pipe.

Pipeline Integrity is responsible for recommending prevention and maintenance for internal corrosion that includes:

- treatment needs, concentrations, and application methods
- suitable chemical properties
- appropriate internal inspection tools, if required
- treatment locations

NOTE: Past performance and present day monitoring of inhibitor effectiveness continually affect these decisions.

Pipeline Integrity is responsible for developing or assisting the regions to develop excavation programs based on data from internal inspection tool runs.

Pipeline Integrity is responsible for reviewing hydrogen foil activity annually to assess overall internal corrosion mitigation, and for initiating remedial action based on conclusions.

NOTE: For more information on the company's internal corrosion monitoring and corrosion inhibitor plan, contact Pipeline Integrity.

Requirements

Coatings

All buried or submerged metallic structures must have a protective coating applied.

NOTE: For more information on selecting and installing protective coatings, see the Painting, Coating and Lining Specifications database, or Engineering Standard D04-102, Painting, Coating and Lining (CAN), or contact Pipeline Integrity.

Exposed Pipe

[redacted]

If the coating is ineffective, remove a sufficient area of the coating and examine the pipe surface for evidence of external corrosion. If there is evidence of external corrosion, measure the extent in accordance with the criteria in 06-02-02, Defect Evaluation and Repair Methods.

If external corrosion exceeds tolerable limits, notify Operations management immediately so they can:

- initiate repairs
- consider the need to reduce operating pressure
- USA: consider the need for a Safety Related Condition Report (see Book 1: General Reference, Tab 02, Incident Reporting).

NOTE: Tolerable limits for corrosion include:

- metal loss less than that allowed by Remaining Strength of pipe (RSTRENG) assessment criteria
- pit depth less than 80% of wall thickness (WT)

Unexposed pipe in the vicinity of external corrosion that requires remedial action must be evaluated following the next internal inspection in accordance with Engineering Standard D0[illegible]01, Pipeline Corrosion Assessment, and Tab 06, Pipe Repair and Modification.

Above Ground Pipe

NOTE: Above ground pipe is pipe originally installed above grade and intended to be exposed to the atmosphere.

At least annually, inspect above ground pipe, equipment, and associated components (e.g., foundations, supports, fittings, and valves) down to slightly below grade level for conditions such as:

- evidence of corrosion or pipe deformation
- deterioration of paint, tape or other coatings
- deterioration of foundation or supports, including cracks, disintegrating concrete, damaged steel, or visual signs of slumping, leaning, or undercutting
- anything with the potential for damaging piping, equipment, or the environment

Lakehead Pipe Line Company, L.P.
Corrosion Inspection Report

LPL Report Number: JAThompson-2003-001 Report Date: 04/29/2003

Part A - General Information Concerning Excavation

Line Number and Size	MilePost/Station	Tract No.	Stationing
Line - (")			

Purpose of Excavation	Soil Type	Terrain Type
Recoating		

Complete These Lines if Excavation is for Instrument Pig Investigation

Type of Pig	Indication No.	Log Footage	Reported Grade Depth or RPR

Corrosion Type	Max Depth	Anomaly Size

Part B - Inspection Results

Condition of Outside of Pipe

Comments

Existing Coating is :
Condition of Coating :
Comments :
New Coating is : Coating Length is :
Pipe to Soil Potential :
Comments :
Condition of Inside of Pipe :
Comments :
Inspected By : Date Inspected:

Part C - Signatures

Pipe Line Foreman

Date
04/29/2003

C. Safety-Related Condition Report Items.

195.402 (f) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of 195.55.

The procedure did not provide clear direction concerning recognition and discovery of safety-related conditions.

a) 195.55 Reporting safety-related conditions.

195.55 (a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with 195.56 the existence of any of the following safety-related conditions involving pipelines in service:

195.55 (a) (1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

The procedure did not include adequate guidance on general and localized corrosion as a safety-related condition.

b) 195.56 Filing safety-related condition reports.

195.56 (b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.
(4) Name, job title, and business telephone number of person who determined that the condition exists.
(5) Date condition was discovered and date condition was first determined to exist.
(6) Location of condition, with reference to the State (and town, city, or country) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

The procedure did not specifically include direction covering the eight informational elements that must be included in a safety-related condition report.

Requirements

Environment, Health & Safety Committees

Environment, Health & Safety (EH&S) committees meet as follows:

- Senior Management Environment, Health & Safety Committee (SMEHSC) meets 2 times per year
- Pipeline Operations Environment, Health & Safety Committee (POEHSC) meets 3 times per year
- Edmonton/Calgary/Duluth Office Environment, Health & Safety policy committees meet 4 times per year
- safety advisory team (SAT) meets 3 times per year
- regional EH&S policy committees meet 4 times per year
- local EH&S committees meet monthly

NOTE: For more information on EH&S committees, including committee structure and responsibilities, see the Safety & Environment Intranet site.

Local EH&S Committees

Local EH&S committees must hold monthly meetings. Attendance at meetings is mandatory; the employee's immediate supervisor must approve absences.

Local EH&S committee meetings may include:

- discussion of environment, health and safety suggestions and concerns (e.g., concerns about worksite hazards)
- review of Book 2: Safety and other relevant manuals
- review of Incident bulletins
- review of meeting minutes from other locations within the region
- discussion of a topic related to the environment, health, or safety
- USA: review of reporting criteria for safety-related conditions upon first discovery (see Book 1: General Reference, 02-02 [illegible] Incident Reporting-USA)

Regional Office EH&S Meetings

Regional offices must hold 4 meetings annually.

Table 1—*continued*
Incident Reporting Requirements—USA

Reporting Criteria	Report	Submitter	Receiver	When	Comments
In **Indiana**, a pipeline leak or spill that threatens waters above or below the earth (includes a spill onto the ground, except if the spill does not cross facility boundaries and can be cleaned up within 12 hrs).	verbal	regional management	Indiana Dept. of Env. Mgmt.	immediately	(317) 233-7745 *24 hrs*
In **New York**, a pipeline spill or discharge into waters above or below the earth (includes a spill onto the ground that might flow into waters, likewise for spills outside the state).			New York Dept. of Environment Conservation		(518) 457-7362 *24 hrs*
all leaks	Leak History	regional management	Leak History database	within 30 days	
The following conditions involving pipelines in service: • Pipe defect requiring repair, as described in Book 3: Pipeline Facilities, 06-02-02, Defect Evaluation and Repair Methods • Movement or abnormal loading of the pipeline by environmental causes, e.g., washouts and landslides • Material defect or damage that affects the serviceability of the pipeline, e.g., cracked metal, broken conduit, valve damage • Pressure over 110% MOP due to equipment malfunction or operating error • A pipeline leak that constitutes an emergency • Any safety-related condition that results in a shutdown or operating pressure reduction over 20%	Safety-Related Condition Report	Compliance & Risk Management	Office of Pipeline Safety (OPS) Line shutdown in Minnesota for safety-related condition must be reported to the State Duty Officer (800) 422-0798	within 5 days of determining that the condition is safety-related, but no later than 10 days after discovery of the condition	Do not report if an Accident Report is filed for the same condition. A report is not required if the condition is more than 220 yards from habitation or place of assembly, except if within paved road or RR ROW, or threatens a body of water.
A hazardous material spill during transportation (including loading, unloading and temporary storage) involving company-owned, leased or rented vehicles that results in: • evacuation of the general public lasting one or more hrs • shutdown or closure of one or more transportation arteries for one hour or more • fire, breakage, spillage or suspected contamination involving radioactive materials • death or personal injury requiring hospitalization • property damage estimated to exceed $50,000	verbal	regional management	National Response Center (NRC)	immediately	(800) 424-8802 *24 hrs*
A hazardous material spill during transportation (including loading, unloading and temporary storage) that meets the criteria for verbal report (above). An unintentional release of a hazardous material during transportation in a quantity equal to or greater than its reportable quantity.	Hazardous Materials Incident Report (DOT Form F 5800.1)	Safety & Environment	Office of Hazardous Materials Transportation	within 30 days	

Temporary Repairs
Mechanical leak clamps and bolt-on sleeves are considered temporary repairs, unless they are welded permanently in place.

Inspect temporary repairs within 1 year of installation to verify the integrity of the repair.

Corrosion
No repair is required where the maximum depth of corrosion (either internal or external, or the sum of internal and external) is ≤20%.

Table 1 includes guidelines for evaluating whether corrosion with maximum depths >20% needs repair.

Gouges, Grooves and Arc Burns
Grinding is used to completely remove gouges, grooves and arc burns, and must be done to produce a smooth transition with the surrounding pipe surface. Use dye penetrant or magnetic particle inspection (MPI) to confirm that (a) gouges and grooves are removed and that (b) there are no cracks at the bottoms of the defects.

NOTE: For information on removing arc burns, see Book 4: Welding, Tab 02, Maintenance and Repair Welding.

Measure the minimum remaining wall thickness (WT) in the ground area. A sleeve is not required where grinding has reduced the nominal wall thickness by less than 40%, and the allowable length of grinding calculated in 06-03-10, Grinding Repairs is permissible.

Buckles
A buckle usually occurs at a sharp bend and is more localized than a dent. If a buckle exceeds the limits of pipeline deformity shown in Table 3, it must be cut out as a cylinder and replaced by another section of pipe.

Use a pressure-containment sleeve to repair buckles that do not exceed the limits of pipeline deformity.

Table 1
Corrosion Assessment and Repair

Location of Corrosion	Remaining Wall Thickness (RW) (% of nominal wall)	Allowable Longitudinal Length	Sleeve Repair Methods
pipe body, external only	21% – 80%	see 06-04-02[1]	pressure-containment or Clock Spring®
	≤20%	none	pressure-containment
pipe body, internal or combined internal/external	51% – 80%	see 06-04-03[4]	pressure-containment
	≤50%	none	pressure-containment
HAZ[2], external only	51% – 80%	see 06-04-02[1]	pressure-containment or Clock Spring®
	≤50%	none	pressure-containment
HAZ[2], internal[3] or combined internal/external	51% – 80%	see 06-04-03[4]	pressure-containment
	≤50%	none	pressure-containment

NOTES

1. An Engineering Critical Assessment (ECA) using the RSTRENG effective area method can also determine the need to repair pits exceeding the allowable longitudinal length (see Engineering Standard D03-101, Pipeline Corrosion Assessment).
2. The heat affected zone (HAZ) includes the weld plus the area within 12.7 mm (0.5 in.) of the weld.
3. Rolled-in nonmetallic inclusions confirmed by ultrasonic inspection do not require repair.
4. Where internal and external corrosion exist together, use the allowable lengths for internal corrosion in 06-04-03, Tolerable Limits of Internal Corrosion.

Dents

Dent Depth Measurement

Calculate dent depth using the formula (see Figure 1):

$$B = D_{NOM} - D_{MIN} - \frac{(D_{MAX} - D_{NOM})}{2}$$

Where:

B	=	dent depth
D_{NOM}	=	nominal outside pipe diameter
D_{MIN}	=	pipe diameter measured with a pipeline caliper across the deepest part of the dent
D_{MAX}	=	pipe diameter measured 90° from the deepest part of the dent
A	=	measured dent depth using a straight edge

ENBRIDGE

Safety Related Condition Report

Enbridge Energy Company, Inc.

Section 1 **Discovery of Potential Safety Related Condition**	Principal Address of Operator: Street: City: State: Zip: Area: Size: X-Y: M.P. Tract No.: Survey Station No.: Compressor Station: Pump Station: Product Transported: Distance of Nearest Dwelling: Direction of Nearest Dwelling: Nearest Dwelling Type: Within the Right-of-Way of an Active Railroad, Paved Road, Street or Highway: Yes: No: Date Discovered: Time Discovered: Date Condition Determined to Exist:
Section 2 **Nature of Potential Safety Related Condition**	Corrosion Ref. No.: Overpressure: Unintended Movement or External Loading: Leak Requiring Emergency Response: Material Defect: Reduction of Current Operating Pressure: Physical Damage:
Section 3 **Current Operating Conditions**	Diameter: Wall Thickness: Grade: Seam Type: MAOP:
Section 4 **Additional Remarks & Information**	Circumstances leading to discovery: Significant Effects of Condition on Safety:
Section 5 **Corrective Action Taken**	Follow-up: Anticipated Schedule:
Section 6 **Identification**	Discovered By: Title: Phone: Date: Reported To: Title: Phone: Date: Submitted By: Title: Phone: Date: Safety Related Condition Confirmed By: Title: Phone: Date:

Distribution:	FREQUENCY:	RETENTION:
Compliance File, Office of Pipeline Safety	As Required	Life of Facility

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

q) 195.573 What must I do to monitor external corrosion control?

195.573 (a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

a) 195.573 (a) (2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96.

The procedure did not provide clear direction concerning the criteria for a close interval survey and when a close interval survey is required.

b) 195.573 (e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401 (b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452 (h).

The procedure did not provide clear direction concerning the criteria to determine if a deficiency involves a pipeline under an integrity management program and clear direction on what the time intervals are for completing repairs on deficiencies.

USA

Close Interval Survey

Close interval surveys ensure cathodic protection systems are adequate. Close interval surveys must be taken:

- within 15 to 24 months of installing a new pipeline adjacent to an existing pipeline
- within 12 to 24 months of installing a cathodic protection system on a new pipeline
- within 12 to 24 months of installing a new/replacement groundbed on a pipeline
- during the annual cathodic protection survey where test stations are impractical, at intervals of 2 to 7 miles
- in areas where coating degradation is suspected at intervals of 5 to 7 years

Rectifiers

Rectifiers must be inspected monthly.

NOTE: For more information, see the applicable Maximo Job Plan.

Advise the regional corrosion technician of defective rectifiers immediately.

Repairs to rectifiers must be completed within 8 weeks from the time of inspection.

Critical Bonds

Interference bonds, or "critical bonds," must be inspected at least 6 times a year at intervals not exceeding 10 weeks.

NOTE: Critical bonds are interference bonds whose failure would jeopardize the integrity of the cathodic protection system. An interference bond is considered "critical" when, with the bond disconnected, the pipe-to-soil potential reading is below 850 mV or 100 mV criteria.

Inspections of critical bonds must include:

- pipe-to-soil potential readings from each pipeline with the bond connected
- magnitude and direction of current flow through the bond cable
- inspecting all connections for loose or frayed wires

Purpose

Pipeline defects are categorized by type, severity and, in the USA, by location. Repair equipment and sleeving techniques are available for every type of defect that could be encountered.

NOTE: Where practical or when physical or environmental conditions make it difficult to properly install sleeves, it may be necessary to replace the pipe.

Guidelines

USA

High Consequence Areas

NOTE: Pipeline Integrity specifically identifies defects that are located in a High Consequence Area (HCA) to field employees.

Immediately repair defects in a HCA if:

- metal loss is >80% of nominal wall thickness
- calculation of remaining strength shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly
- a dent above the 4 and 8 o'clock positions on a pipeline (a) has any indication of metal loss, cracking or a stress riser, or (b) has a depth >6% of nominal pipe diameter
- Pipeline Integrity identifies an immediate concern

Within 60 days complete evaluation and remediation in a HCA if a dent:

- above the 4 and 8 o'clock positions on a pipeline ≥NPS 12 has a depth >3% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.
- on the bottom of a pipeline has any indication of metal loss, cracking, or a stress riser

Within 180 days, complete evaluation and remediation in a HCA if:

- a dent at a girth weld or longitudinal seam weld on a pipeline ≥NPS 12 has a depth >2% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.
- a dent above the 4 and 8 o'clock positions on a pipeline ≥NPS 12 has a depth >2% of nominal diameter, or on a pipeline <NPS 12 has a depth >0.250 in.

- a dent on the bottom of the pipeline has a depth >6% of the pipeline diameter
- calculation of remaining pipe strength shows a safe operating pressure less than the current established maximum operating pressure at the location of the anomaly
- an area of general corrosion has a predicted metal loss of >50% of nominal wall
- predicted metal loss >50% of nominal wall is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
- a potential crack indication when excavated is determined to be a crack
- corrosion is found on or along a longitudinal seam weld
- a gouge or groove is >12.5% of nominal wall

NOTE: If significant anomalous conditions are identified in a HCA, operating pressure must be temporarily reduced.

Repair Methods

Determine repair methods for pipeline defects by considering:

- size and shape of the defect
- roundness of the pipe
- presence of dents
- surface corrosion and interaction of corroded areas
- presence of cracks

Repair leaking and nonleaking pipeline defects by approved methods.

Reinforcement Sleeves

Clock Spring® composite sleeve devices are an acceptable alternative to the steel split sleeve for permanently repairing corrosion and dents (see Table 1 and Table 2).

NOTE: For more information, see 06-03-19, Installing Clock Spring Reinforcement Sleeves.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

r) 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

195.575 (a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

195.575 (b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

195.575 (c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

195.575 (d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

195.575 (e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

The procedure did not provide clear direction concerning what facilities require electrical isolation and what inspections, tests and additional safeguards are required.

- inspecting all connections for loose or frayed wires
- minor repairs, if practicable

Electrical Isolation

Electrical isolation must be achieved and maintained in accordance with NACE Standard RP0286-2002, Electrical Isolation of Cathodically Protected Pipelines.

Electrical isolation must be checked annually, not exceeding 15 months.

USA

Casings

All casing to pipe potentials must be reviewed annually to determine the effectiveness of casing isolation. If a casing isolation failure is suspected, additional testing is required in accordance with NACE Standard RP0200-2000, Steel-Cased Pipeline Practices (Item No. 21091).

When a casing is considered shorted and is recommended for repair, review the latest metal loss survey data as soon as practical to ensure the integrity of the carrier pipe. Complete at least one of the following corrective measures within 12 months, such as:

- excavate and reposition the carrier pipe within the casing and ensure the test lead wires are not shorted
- clean and flush the annular space between the carrier pipe and the casing
- remove the casing
- fill the annular space between the carrier pipe and the casing with a high dielectric casing filler
- remove or replace the carrier pipe

NOTE: Other corrective measures also may be used.

Records

Monthly Rectifier Report

Record inspections of critical bonds using either the Monthly Rectifier Report, or a report specific to the region.

Record the voltage and amperage of each rectifier inspected on the Monthly Rectifier Report or in the applicable Maximo Job Plan.

B. Maintenance and Normal Operations Items.

4. 195. 402 (c) (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

s) 195.577 What must I do to alleviate interference currents?

195.577 (a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

195.577 (b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

The procedure did not provide clear direction concerning designing and installing cathodic protection systems to minimize effects on existing adjacent metallic structures.

Purpose

This standard identifies the responsibilites and requirements for monitoring the cathodic protection system to ensure the equipment is functioning properly.

Responsibilities

Corrosion Technician

Regional corrosion technicians are responsible for ensuring:

- adjustive surveys
- rectifier readings
- critical bond readings
- electrical isolation checks
- repairs and upgrades to cathodic protection systems
- installation of new cathodic protection systems

NOTE: For information on installing new cathodic protection equipment, see Engineering Standard D04-101, Cathodic Protection.

In addition, regional corrosion technicians are responsible for:

- monitoring company/adjacent utilities to ensure current interference testing if the cathodic protection system of an adjoining utility changes
- developing remediation strategies, including critical bonds, to minimize adverse effects on company/adjacent structures if interference tests detect deleterious current interference

NOTE: Regional corrosion technicians keep informed of changes to cathodic protection systems by participating in corrosion control committees in the region (e.g., NACE, SOCE).

USA

- conducting cathodic protection studies and facilitating research

USA

- maintaining historical cathodic protection information

USA

- completing corrosion technician performance-based training (PBT), and achieving NACE CP Level 1 Certification within 1 year of employment

1

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

LETTER OF CONCERN

November 10, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dan C. Tutcher
President
Enbridge Energy, Limited Partnership
Suite 3300
1100 Louisiana
Houston, TX 77002-5217

CPF No. 3-2003-5025C

Dear Mr. Tutcher:

On August 13 - August 14, 2003 and September 16 - September 18, 2003, a representative of the Central Region, Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your field facilities located within the states of Michigan and Wisconsin.

The inspection disclosed the following items of concern. Please give these items your attention.

1. At MP 1149.44, the right-of-way is overgrown with weeds, small bushes, plants and small trees.

2. At MP 1226.20, the Gogebic Pump Station, the paint coating on the station piping is deteriorated.

3. At MP 1235.55, the right-of-way is overgrown with weeds, small bushes, plants and small trees.

These items were discussed with your representatives during the inspection. They indicated that these items would receive attention.

The Office of Pipeline Safety appreciates your attention in these matters and good faith efforts to promote continued safety in your organization.

If we can answer any questions or be of any assistance, please contact us at (816) 329-3800.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. Mark J. Willoughby
Manager, U.S. Compliance & Risk Management
Enbridge Energy, Limited Partnership
119 N. 25th Street East
Superior, WI 54880

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Enbridge Pipelines (Lakehead) L.L.C.
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Mark J. Willoughby, Manager
U.S. Compliance & Risk Management
Tel 715 394 1534
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mark.willoughby@enbridge.com

ENBRIDGE™

January 6, 2004

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2003-5025C

Dear Mr. Huntoon:

Your "Letter of Concern," dated November 10, 2003, addressed three items that were identified during your recent onsite pipeline safety inspection of field locations on our Line 5 facilities in Wisconsin and Michigan. Enbridge Pipelines values the opportunity to address these items and appreciates the cooperative relationship demonstrated by this dialog. This response is intended to clarify the issues mentioned in your letter.

Item 1. **Overgrown right of way at MP 1149.44**

Contract and company brushing had started the week of August 11, 2003 and didn't get to this location until we had already covered it during the audit. This location has been completed and photos showing this are attached.

Item 2. **Deteriorated paint at Gogebic Station**

Contract painting had already begun prior to the audit but hadn't reached Gogebic Station before the audit was completed. Other sites such as Saxon Station had been completed and were viewed by Phil Archulletta. This Station has since been completed and photos of the site are attached.

Item 3. **Overgrown right of way at MP 1235.55**

Contract and company brushing had started the week of August 11, 2003 and didn't get to this location until we had already covered it during the audit. This location has been completed and photos showing this are attached.

I trust that these explanations and attachments have addressed the concerns outlined in your letter. Should you have any further questions or concerns, please feel free to contact Jay Johnson at 715 / 394-1512 or me.

Sincerely,

Mark Willoughby

Attachments

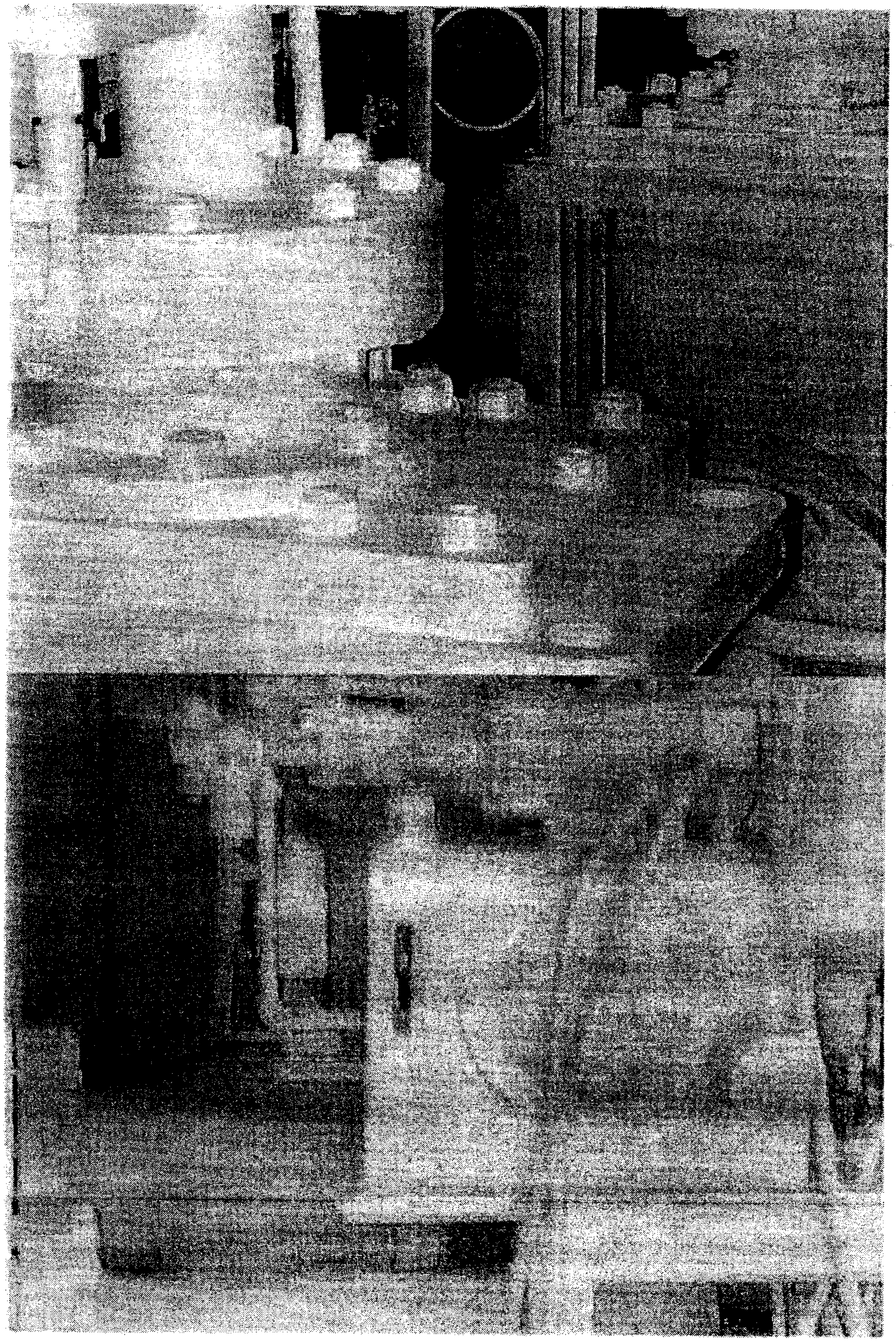
c: Steve Irving
Greg Sevick
Mark Sitek
Dan Tutcher

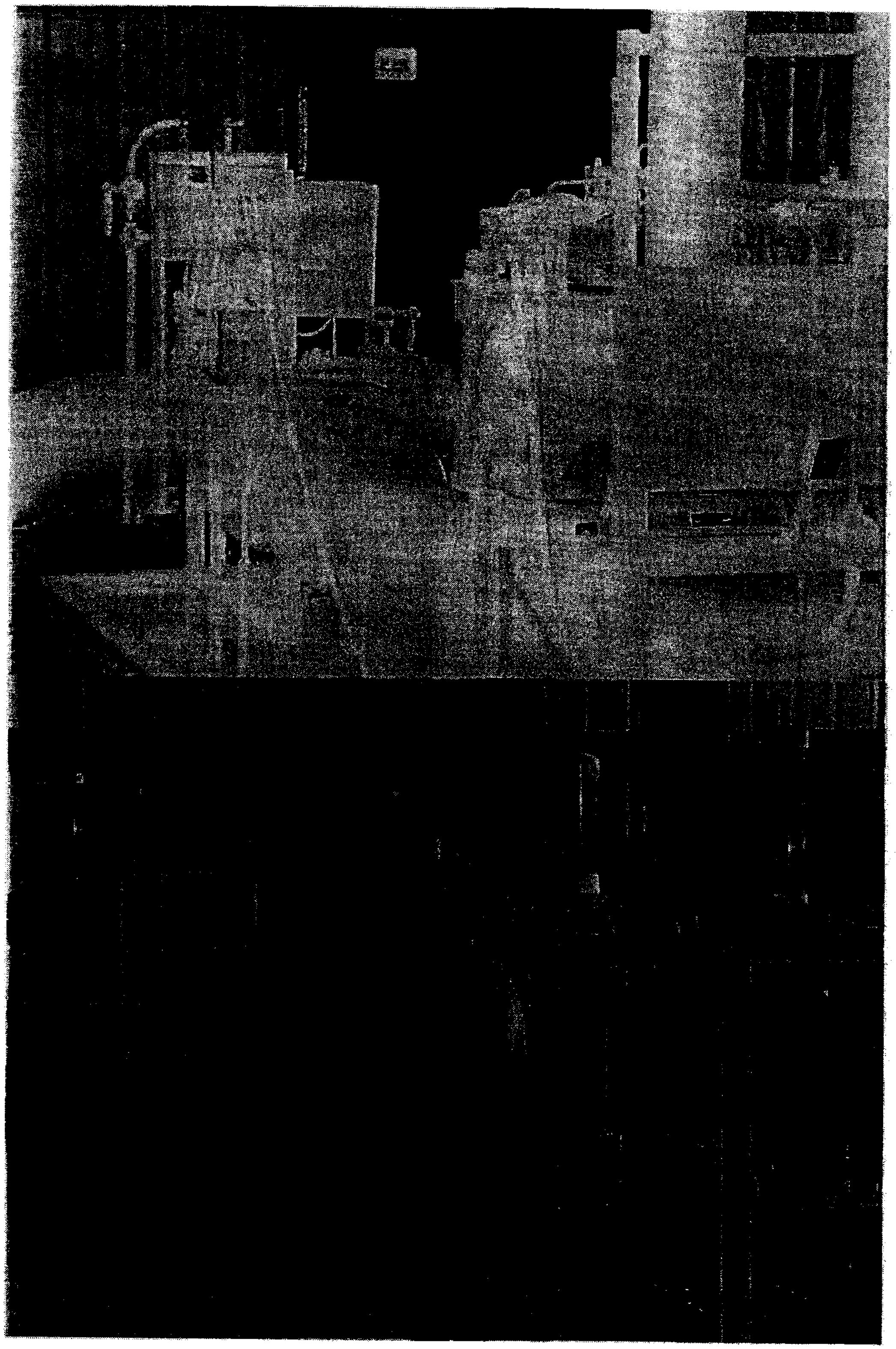
MP 1149.44

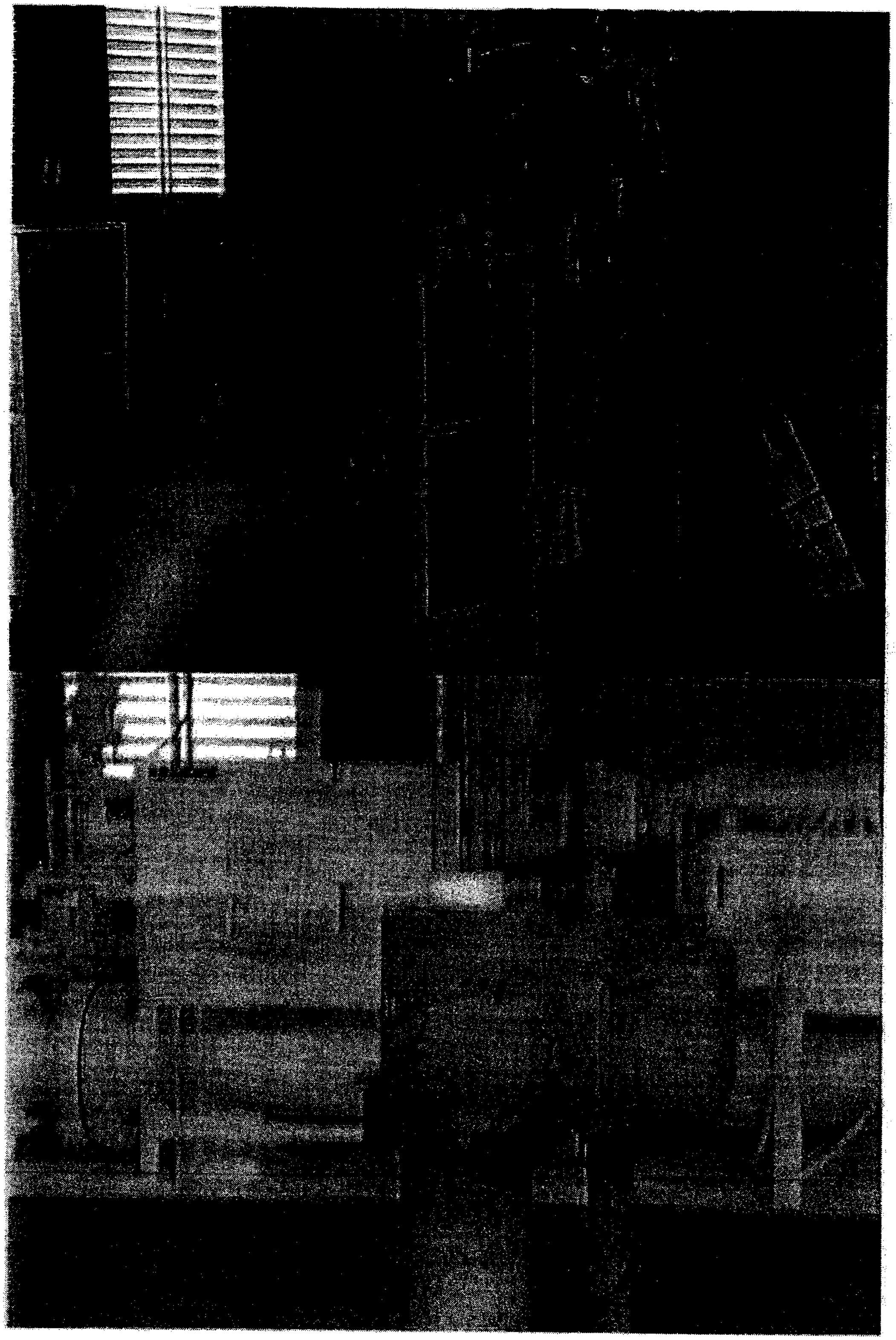
View upstream from the recreational corridor across the blacktop road.

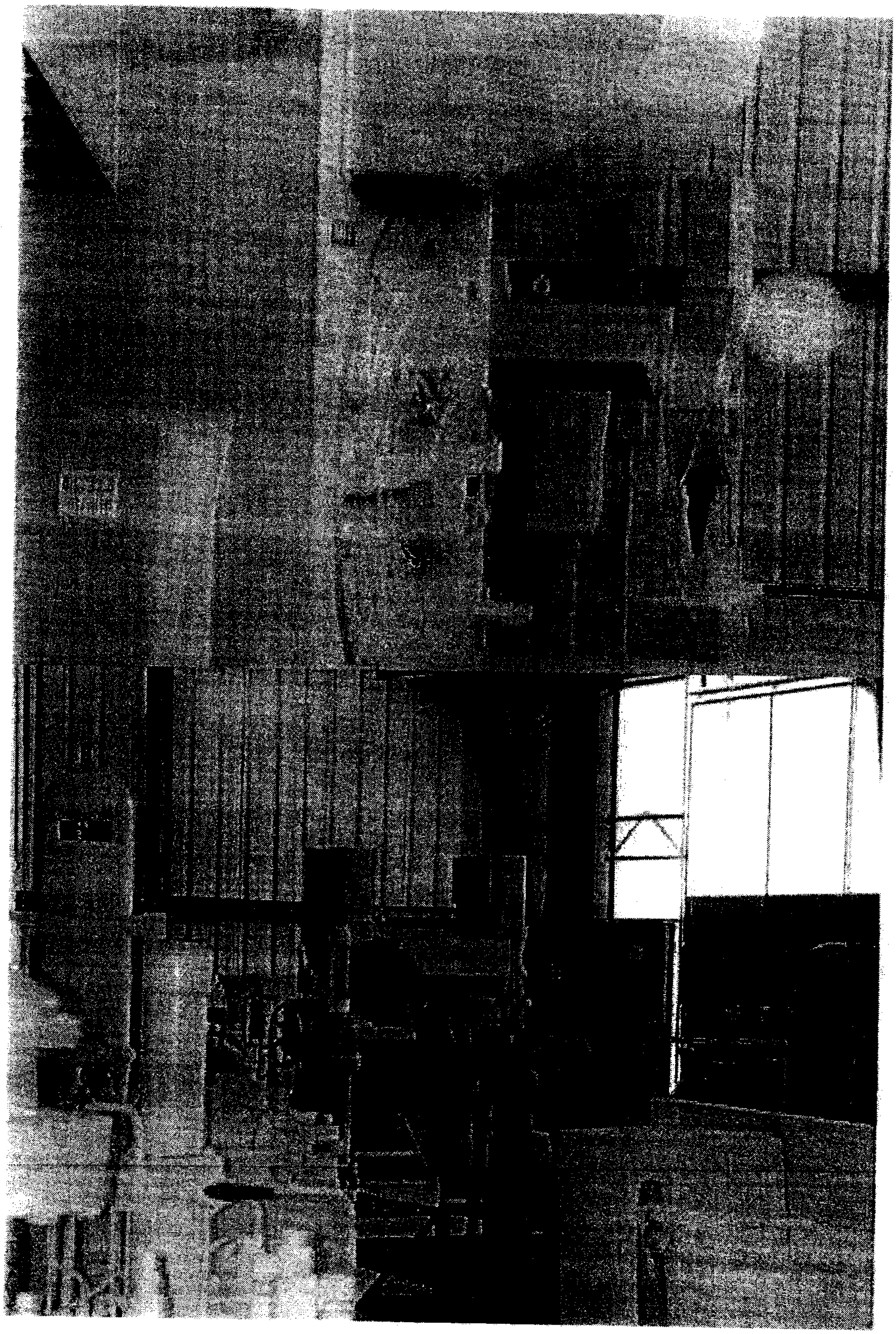
View downstream from blacktop road across recreational corridor into field.

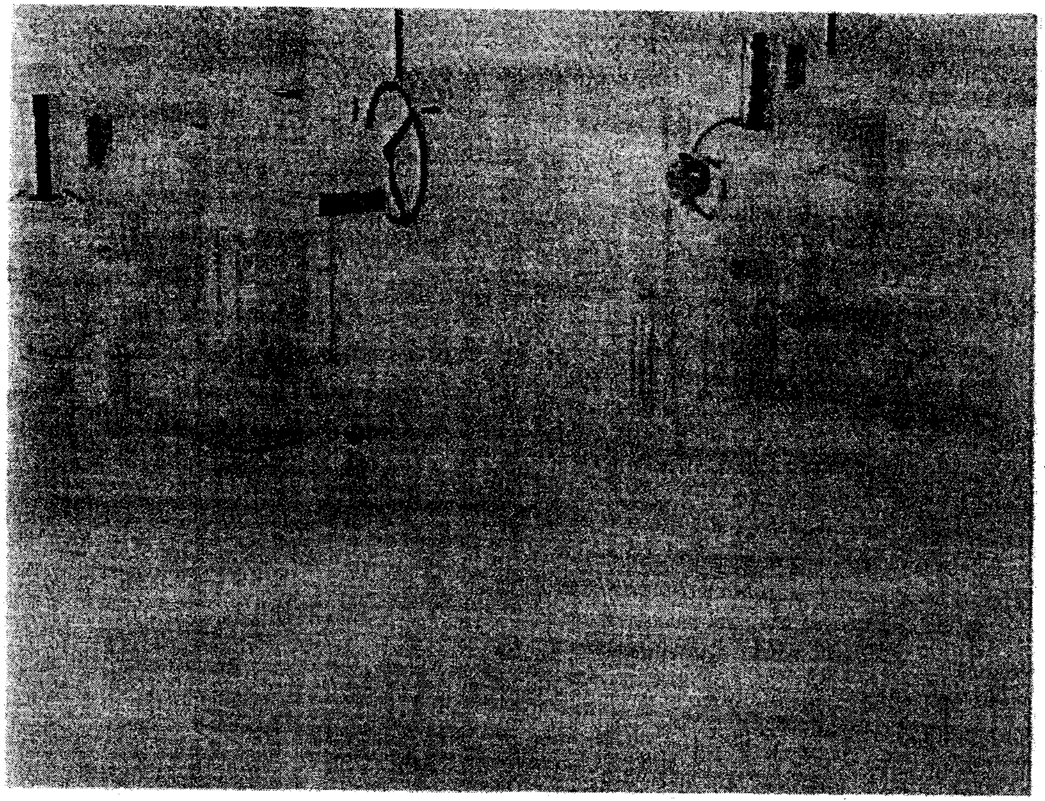
View upstream from blacktop road. R-O-W turns left at power lines.











MP 1235.55

View downstream of road crossing.

View upstream of road crossing.

2

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION AND PROPOSED CIVIL PENALTY

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 5, 2004

Mr. Dan Tutcher
President
Enbridge Energy, Limited Partnership
1100 Louisiana
Suite 2950
Houston, TX 77002

CPF No. 3-2004-1007

Dear Mr. Tutcher:

On September 3-6, 2002, October 15-16, 2002 and March 10-11, 2003 representatives of the Central Region, Office of Pipeline Safety, and the Michigan Public Service Commission, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of Enbridge's Vector pipeline facilities and records in Illinois, Indiana, and Michigan.

As a result of the inspections, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 192. The items inspected and the probable violations are:

1. **§192.225 Welding – General**

   § 192.225(b) requires that each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

Enbridge failed to have qualified welding procedures for the construction of the Crete Meter station project.

The meter station was put into service in early 2002, however, Enbridge personnel were unable to show the destructive qualifying tests for the Mango No. 1 procedure used during this project. As a result, Enbridge qualified the procedure in October 2002, after the project was completed and in operation.

2. **§ 192.465 External Corrosion control: Monitoring.**

§ 192.465(b) requires that the operator inspect each cathodic protection rectifier or other impressed current power source six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.

Enbridge failed to inspect three (3) rectifiers between September 20, 2001 and February 20, 2002.

The three (3) rectifiers were located at M/L Valves 3, 5, and 18. There was a five (5) month interval between the readings.

3. **§ 192.706 Transmission lines: Leakage surveys.**

§192.706(a) requires the operator to conduct leakage surveys of a transmission line at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted-

(a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year

The Company failed to conduct two leak surveys within the calendar year at the class three locations in Illinois and Indiana.

One survey was done on 7/12/01, and the second survey was done on 1/2/02.

In addition, at the class three location in Michigan, one survey was done on 12/31/01, and the next was done on 8/22/02. This exceeded the 7 ½ month criteria.

4. **§ 192.731 Compressor stations: Inspection and testing of relief devices.**

§ 192.731(a) requires each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

At the Springville Compressor station, Enbridge did not inspect two relief valves for 2001 and 2002.

The two relief valves, PSV 108 and 208, are thermal relief valves on the compressor recycle loop. The relief valves had not been inspected since their installation in 2000. Your personnel stated that this was an over-sight.

5. **§192.743 Pressure limiting and regulating stations: Testing of relief devices.**

§192.743(b) requires the operator to review and calculate the required capacity of the relieving device at each station at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities should be compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

Enbridge failed to conduct an annual review of the capacity calculations for the relief at the Alliance/Northern Border interconnect and for two relief valves at the Springville Compressor Station.

At the Alliance/Northern Border interconnect, the capacity of the relief valve at that location was not checked in 2001. In addition, at the Springville Compressor station, PSV 108 and 208 relief valves did not have their capacities checked in 2001 and 2002.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violations persist up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and it is her recommendation that you be preliminarily assessed a civil penalty as follows:

Item 1 -	$ 5,000
Item 4 -	$ 3,000
Item 5 -	$ 3,500
Total	$11,500

For Items 2 & 3, we have reviewed the circumstances and supporting documents involved for the violation in this case, and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations, we will take enforcement action when and if the continued violations come to our attention.

In addition to this, the inspection revealed a concern that we would like to bring to your attention. During the inspection, your personnel showed our inspectors an instant off survey of the line.

Several readings read below a -0.85v without the current applied. Company personnel felt that if the "on" readings are above -0.85v, then no action needed to be taken. OPS reiterates that the cathodic protection readings must meet the -0.85v criteria with IR drop considered. When conducting an instant-off survey, the Company is considering the IR drop, and therefore, any readings below the -0.85v without current applied must be addressed with remedial action or proven with another criteria.

The above-mentioned item was discussed with your representative during the inspection. Your representative indicated that this item would receive attention. Thank you for your attention to this matter.

Also, attached to and made a part of this Notice is a description of the available procedures for responding to this Notice. Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights under 49 CFR 190.209. No response or a response which does not contest the allegations in the Notice authorizes the Associate Administrator for Pipeline Safety to find the facts to be as alleged herein and to issue appropriate orders. The 30 day period for response may be extended for good cause shown, and submitted within the original 30 day period.

Please refer to CPF No. 3-2004-1007 in any correspondence or communication on this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

I. Procedures for Responding to a Notice of Probable Violation:

The requirements of 49 C.F.R. Part 190, Subpart B govern your response to this Notice of Probable Violation ("Notice").

Within 30 days of receipt of a Notice, the respondent shall respond to the Regional Director who issued the Notice in the following way:

(a) When the Notice contains a proposed **civil penalty*** --

(1) Pay the proposed civil penalty, authorizing OPS to make findings and to close the case with prejudice to the respondent. Payment terms are outlined in Attachment A;

(2) Submit written explanations, information, or other materials regarding the merits of the allegations and seek elimination or mitigation of the proposed civil penalty; or

(3) Request a hearing as described below to contest the allegations and proposed assessment of a civil penalty.

* Failure of the respondent to respond within 30 days of receipt of a Notice containing a civil penalty constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

(b) When the Notice contains a proposed **compliance order** --

(1) Notify the Regional Director that you intend to take the steps in the proposed compliance order;

(2) Submit written explanations, information, or other materials in answer to the allegations in the Notice and object to or seek clarification of the proposed compliance order items in whole or in part;

(3) Request a hearing as described below to contest the allegations in the Notice; or

(4) Request consideration of a consent order as described below pursuant to 49 C.F.R. § 190.219.

(c) When the Notice contains an **amendment** of plans or procedures --

(1) Notify the Regional Director that you intend to take the steps in the proposed amendment of plans or procedures;

(2) Submit written explanations, information, or other materials in answer to the allegations in the Notice and object to or seek clarification of the proposed amendment items in whole or in part; or

(3) Request a hearing as described below to contest the allegations in the Notice.

(d) When the Notice contains **warning** items -- These items may be addressed at the operator's discretion; however, no response is required.

II. Procedure for Requesting a Hearing

A request for a hearing must be in writing and accompanied by a statement of the issues which the respondent intends to raise at the hearing. The issues may relate to the alleged violations, new information, or to the proposed compliance order or proposed civil penalty amount. A respondent's failure to specify an issue may result in waiver of the right to raise that issue at the hearing. The respondent's request must also indicate whether or not respondent will be represented by counsel at the hearing. Failure to submit a request for a hearing in writing waives the right to a hearing. In addition, if the amount of the proposed civil penalty or the proposed corrective action is less than $10,000, the hearing will be held by telephone, unless the respondent submits a written request for an in-person hearing. Complete hearing procedures can be found at 49 C.F.R. § 190.211.

III. Extensions of Time

An extension of time to prepare an appropriate response to a Notice may be granted, at the agency's discretion, following submittal of a written request to the Region Director. The request must indicate the amount of time needed and the reasons for the extension. The request must be submitted within 30 days of receipt of the Notice.

IV. Freedom of Information Act

Any material prepared by RSPA/OPS, including the violation report, this Notice, and any order issued in this case, and/or any material provided to OPS, may be considered public information and subject to disclosure under the Freedom of Information Act (FOIA). If the information you provide is security sensitive, privileged, confidential or may cause your company competitive disadvantages, please clearly identify the material and provide justification why the documents, or portions of a document, should not be released under FOIA. If we receive a request for your material, we will notify you if RSPA/OPS, after review of the materials and your provided justification, determines that withholding the materials does not meet any exemption provided under the FOIA. You may appeal the agency's decision to release materials under the FOIA at that time. Your appeal will stay the release of those materials until a final decision is made.

V. Small Business Regulatory Enforcement Fairness Act Information

The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of the Research and Special Programs Administration, call 1-888-REG-FAIR (1-888-734-3247).

ATTACHMENT A – PAYMENT INSTRUCTIONS

Civil Penalty Payments of Less Than $10,000

Payment of a civil penalty of less than $10,000 proposed or assessed, under Subpart B of Part 190 of the Pipeline Safety Regulations can be made by certified check, money order or wire transfer. Payment by certified check or money order should be made payable to the "Department of Transportation" and should be sent to:

General Ledger Branch (AMZ-300)
Federal Aviation Administration
U.S. Department of Transportation
Mike Monroney Aeronautical Center
P.O. Box 25082
Oklahoma City, OK 73125-4915

Wire transfer payments of less than $10,000 may be made through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfer should be directed to the General Ledger Branch at (405) 954-4719, or at the above address.

Civil Penalty Payments of $10,000 or more

Payment of a civil penalty of $10,000 or more proposed or assessed under Subpart B of Part 190 of the Pipeline Safety Regulations must be made wire transfer (49 C.F.R. § 89.21 (b)(3)) through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfers should be directed to the General Ledger Branch at (405) 954-4719, or at the above address.

1. RECEIVER'S ABA NO. 021030004	2. TYPE SUBTYPE (provided by sending bank)
3. SENDING BANK ARB NO. (provided by sending bank)	4. SENDING BANK REF NO. (provided by sending bank)
5. AMOUNT	6. SENDING BANK NAME (provided by sending bank)
7. RECEIVER NAME: TREAS NYC	8. PRODUCT CODE (Normally CTR, or as provided by sending bank)

9. <u>BENEFICIAL (BNF)- AGENCY</u> **<u>LOCATION CODE-/ AC 69-00-1105</u>**	
10. <u>REASONS FOR PAYMENT</u> OBI = Payment for Civil Penalty/RSPA CPF #	

<u>INSTRUCTIONS:</u> You, as sender of the wire transfer, must provide the sending bank with the information for Block (1), (5), (7), (9), and (10). The information provided in blocks (1), (7), and (9) are constant and remain the same for all wire transfers to Research and Special Programs Administration, Department of Transportation.

<u>Block #1</u> - RECEIVER ABA NO. - "021030004". Ensure the sending bank enters this nine digit identification number, it represents the routing symbol for the U.S. Treasury at the Federal Reserve Bank in New York.

<u>Block #5</u> - AMOUNT - You as the sender provide the amount of the transfer. Please be sure the transfer amount is punctuated with commas and a decimal point. **<u>EXAMPLE; $10,000.00</u>**

<u>Block #7</u> - RECEIVER NAME- "TREAS NYC." Ensure the sending bank enters this abbreviation, it must be used for all wire transfer to the Treasury Department.

<u>Block #9</u> - BENEFICIAL - AGENCY LOCATION CODE - **"BNF=/AC-69001105"** Ensures the sending bank enters this information. This is the Agency Location Code for Research and Special Programs Administration, Department of Transportation.

<u>Block #10</u> - REASON FOR PAYMENT - "OBI = Payment for Civil Penalty/RSPA CPF number and your company's name. Example: OBI = Payment for Civil Penalty/RSPA CPF #1-2002-5001/ ABC Pipeline Co.

<u>Note:</u> - A wire transfer must comply with the format and instructions or the Department cannot accept the wire transfer. You, as the sender, can assist this process by notifying, at the time you send the wire transfer to the General Accounting Division (405) 954-4719.

UNITED STATES DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY

NATURAL GAS PIPELINE SAFETY VIOLATION REPORT

1. **Inspector Name:** Carl Griffis	2. **Date(s) of Inspection:** September 3-6, 2002	3. **CPF #:** 3-2004-1007

4. **Pipeline Operator/ Owner:**
Enbridge Energy, LP

5. **Headquarters Address:** 1100 Louisiana Suite 2950 Houston, TX 77002	5b. **Telephone No.:** 713-650-8900
6. **Inspection Location** Griffith 1500 West Main Street Griffith, IN 46319	7. **Inspection Unit No.:** 29553 IL/IN

8. **Portion of System Inspected:**
The records and field review of the system in IL/IN and MI were inspected in 2002.

9. **Nature and Size of System:**

Number of Miles 274 miles

Commodities Transported Natural Gas

Relevant details with Respect to System This is a new pipeline that went into service in December 2000. The pipeline interconnects with Alliance and Northern Border in Joliet, IL and travels east through IL, IN, and MI. The pipeline crosses the US/Canada border at the St. Clair River south of St. Clair, MI. See attachment 1 for map of the system.

10. **Nature of Probable Violation:**

_____ 1. Problem in Design/Materials
✔ 2. Problem in Construction
_____ 3. Reporting Requirements
_____ 4. Test Requirements
_____ 5. Personnel Qualifications and Training
_____ 6. Anti-Drug Program
_____ 7. Other Operations
_____ 8. Corrosion Control
✔ 9. Pressure Control
_____ 10. Other Maintenance/ Monitoring

_____ 11. Inadequate Procedures
_____ A. Construction
_____ B. Corrosion Control
_____ C. Operations
_____ D. Training
_____ E. Maintenance

Violation No.: 1

11a. CFR § Violated:
§192.225(b)

11b. Summarize what regulations require that the operator did not do:
§192.225(b) requires the operator to ensure that each welding procedure is recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

Enbridge could not produce any records indicating that the procedure used in the construction of the Crete Meter station was qualified.

12. Provide detailed information about violation:
The Company failed to have qualified welding procedures for the Crete Meter station project that was put into service in early 2002. The procedure utilized, Mango No. 1, was from their contractor, Murphy Brothers (See attachment 2). After unsuccessfully trying to locate the results of the qualifying tests, Enbridge qualified the procedures in October 2002. This was after the station was put into service.

13. Public and/or environmental concerns in area of violation:
Since natural gas dissipates in the atmosphere, the affects to the environment is negligible. In addition, since the project was for a station, the danger to the public is minimized, as this is located on Company property which has restricted access.

14a. Persons Interviewed:
Jay Johnson

Title:
Compliance Coordinator

14b. Comments of person interviewed:
They could not find the results of the qualifying tests.

Violation No.: 4

11a. CFR § Violated:
§192.731(a)

11b. Summarize what regulations require that the operator did not do:
§192.731(a) requires that each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

At the Springville Compressor Station, Enbridge did not inspect two relief valves for 2001 and 2002.

12. Provide detailed information about violation:
The Company failed to inspect two relief valves located at the Springville Compressor Station. The relief valves in question are thermal relief valves PSV 108 and PSV 208. They are located on the compressor recycle loop in the station.

13. Public and/or environmental concerns in area of violation:
Since natural gas dissipates in the atmosphere, the affects to the environment is negligible. Again, the danger to the public is minimal as the relief valves in question protect the facilities in the station, which has restricted access to the public.

14a. Persons Interviewed:	**Title:**
Jim Helhowski	Technical Supervisor

14b. Comments of person interviewed:
They indicated that this was an oversight.

Violation No.: 5

11a. CFR § Violated:
§192.743(b)

11b. Summarize what regulations require that the operator did not do:
§192.743(b) requires that a review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

At the Springville Compressor Station, Enbridge did not check the capacities of two (2) relief valves for 2001 and 2002.

At the Alliance/Northern Border interconnect, the capacity of the relief valve was not checked in 2001.

12. Provide detailed information about violation:
The Company failed to check the capacity of two (2) relief valves located at the Springville Compressor Station. The relief valves in question are thermal relief valves PSV 108 and PSV 208. They are located on the compressor recycle loop in the station.

The Company failed to check the capacity of the relief valve at the Alliance/Northern Border interconnect in 2001.

13. Public and/or environmental concerns in area of violation:
Since natural gas dissipates in the atmosphere, the affects to the environment is negligible. Again, the danger to the public is minimal as the relief valves in question protect the facilities in the station, which has restricted access to the public.

14a. Persons Interviewed:
Jim Helhowski

Title:
Technical Supervisor

14b. Comments of person interviewed:
As with the operational inspection of the valves, this was an oversight on their part.

15. **Supporting Documents/Materials:**

Item No.	Description	Source of Document	Remarks
1	Vector System Map	Enbridge	
2	Welding Procedures	Enbridge	

16. **Inspector's Signature**

Date:

17. Compliance History:				
Date:	Place	Describe Violation/Noncompliance	CPF No.	Outcome
6/25/87	Central Region		31987X547	Civil Penalty
7/25/89	Central Region		31989X561	Civil Penalty - $5100
12/17/90	Central Region		319905004	NOA
2/26/01	Central Region		320015003C	LOC
11/10/03	Central Region		320035025C	LOC

18. Gravity of Offense:

Violation 1: Ensuring that the welding procedures are qualified is essential in the integrity of the pipeline system. The Company must be sure that the welds that are produced from this procedure are sound welds, or a release of gas may occur.

Violation 4: Inspection of the relief devices is critical in ensuring that the devices protect the facilities from an over-pressure condition. Although the danger to the public is minimal, the danger to the Company's workers is increased should the device fail.

Violation 5: As in Violation 2, checking the capacities is also crucial to ensuring that these facilities are protected. If changes were made to the station, which affect the through put of the station, inadequate over-pressure protection may occur. Again, although the danger to the public would be minimal, the dangers to the Company's workers would increase.

19. Degree of Culpability:

Enbridge Energy, LP is culpable to the extent that they are familiar with pipeline operations. Although they are relatively new to the natural gas operations, they have been operating one of the largest liquid systems in Central Region. The violations noted here are the same for the liquid operations.

20. Ability to Continue Business:

The Civil Penalties proposed should not affect the Company's ability to continue business.

21. Ability to Pay:

Enbridge Energy, L.P. should have the ability to pay the proposed civil penalty for the cited violation

22. Good Faith in Attempting to Achieve Compliance:

Enbridge Energy has been cooperative in the past in working with OPS central region in trying to achieve compliance.

23a. Proposed Remedy:

_____ **Warning Letter**

✔ **Civil Penalty**

Recommended Amount:

	$ 5,000	Violation 1
	$ 3,000	Violation 4
	$ 3,500	Violation 5
Total	$ 11,500	

_____ **Compliance Order**

_____ **Corrective Action Order**

_____ **Notice of Amendment of O&M Plan**

23b. Analysis of Proposed Remedy:

The proposed civil penalties should be enough to ensure that the company does not miss the required inspections.

24. Region Chief's Signature:

Ivan A. Huntoon

Date:

3/31/04

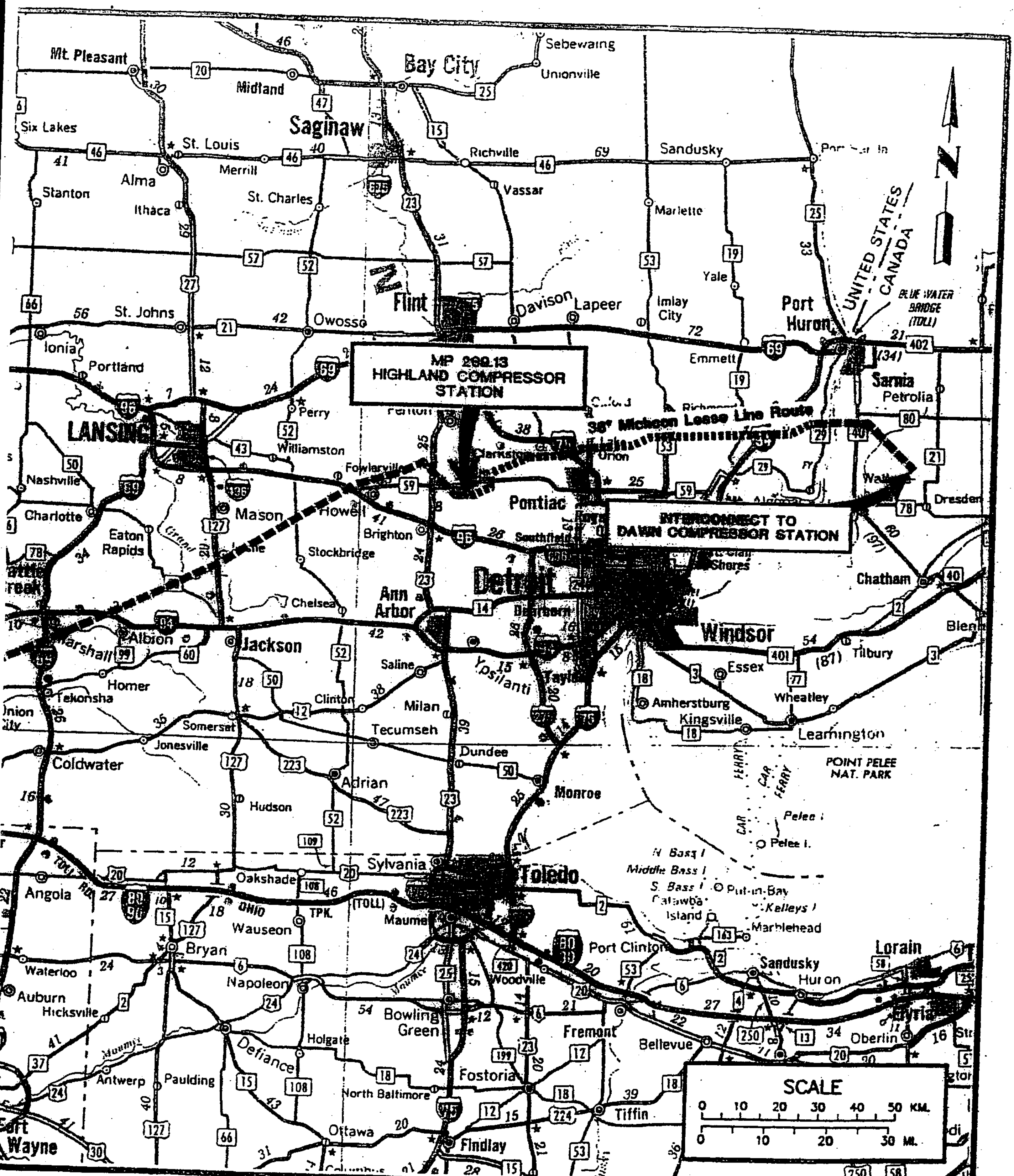
Attachment 1

Vector's System Map

CONSULTANT

UNIVERSAL ENSCO, INC.
[illegible] DRIVE - SUITE 400
P.O. BOX 570248
HOUSTON, TEXAS 77257-0248
(713) 977-7770

Vecto



ipeline

VECTOR PIPELINE
INDEX MAP
Joliet, Illinois to Dawn, Ontario

Attachment 2

Enbridge Welding Procedure

Mango No.1

MANGO WELDING PROCEDURE No. 1 ;SMAW E6010

Specification for Shielded Metal Arc Welding with Class E6010 Lincoln Fleetweld 5P+ electrodes

Procedure Qualification Record Nos: MANGO 1104 1-1(04-25-00), MANGO 1104 1-2(04-25-00), MANGO 1104 1-3(04-26-00), MANGO 1104 1-4(04-26-00), MANGO 1104 1-5(04-26-00), MANGO 1104 1-6(04-26-00), MANGO 1104 1-7(04-25-00), MANGO 1104 1-8(04-25-00), MANGO 1104 1-9(04-25-00) MANGO 1104 1-10(04-26-00), MANGO 1104 1-11(07-28-00), MANGO 1104 1-12(07-28-00), MANGO 1104 1-13(07-28-00) .

Application: Use this procedure on all systems and pressures.

Procedure:

A. PROCESS: The welding shall be done with the Shielded Metal Arc Welding (SMAW) process.

B. PARENT METALS: The materials to which the procedure applies are identified below :

Existing Unknown Steel (24,000psi)
ASTM: A53, A106
API 5L: Grade A25 through X56 (Note limit* on less than 3/16" wall thickness)

which fall into the two following groups:

1) Specified minimum yield strength less than or equal to 42,000 pounds per square inch.
2) Specified minimum yield strength greater than 42,000 pounds per square inch through 56,000 pounds per square inch.

C. DIAMETER AND WALL THICKNESS: This procedure shall apply to all diameters through 48" and wall thicknesses identified in the following groups:

1) Nominal pipe wall thickness less than 3/16 inch.*(Existing Unknown Steel, ASTM:A53, A106, API 5L: Grade A25 through X42 only)
2) Nominal pipe wall thickness from 3/16 inch through ¾ inch.

D. JOINT DESIGN:

- BUTT: Bevel the welding ends to an angle of 30°, +5°, -0°, with a root face of 1/16", +/- 1/32". The bevel shall form a V groove with an included angle of 60°+10/-0. The root opening shall be 1/16", +/- 1/32".
- FILLET: Bevel the welding ends to an angle between 50° and 90° as required for various branch diameter ratios, with a root face of 1/16", +/- 1/32". The bevel shall form a V groove with an included angle of approximately 50°. The root opening shall be 1/16", +/- 1/32".

original Vector mangol procedure

DEC-10-2002 T... MURPHY BRO ESTIMATING 13097995159

Procedure qualified
10/30/02 + 11/7/02

QC

21112 SCO
DAVENPC

WELDER PROCEDURE NUMBER	TEST REPORT NO	DATE
MANUO Welding Procedure No. 1	N-8717	11-07-02
WELDER Roy Dukes / Bill Sadler		
E46		MARK RD / BS

CONTRACTOR Huke Construction	JOB #2200 – MB- Ameren Murphy Brothers	
WELDING PROCESS	SMAW /	Electrical Characteristics D.C. Reversed Polarity
PIPE MATERIAL	TYPE: X-52 O.D. 16" WALL: .375"	MIN. TENSILE: 66,000 PSI
WELDING MACHINE	TYPE: Manual Lincoln 250 SIZE:	
FILLER METAL	GROUP: E-6010 MANUFACTURER: Lincoln	TRADE NAME: 5 P+
JOINT DESIGN	☒ V BEVEL OF 30° ± 5° 0° See attached sheet	☐ OTHER (DESCRIBE)
POSITION	☒ ROLL ☐ FIXED ☐ HORIZONTAL (2G)	☒ VERTICAL (5G)
DIRECTION	☐ UPHILL	☒ DOWNHILL
SHIELDING	☐ GAS ☐ FLUX ☐ DESCR:	FLOW RATE:
TIME LAPSE	ROOT BEAD TO SECOND BEAD Over 24 hours	SPEED OF TRAVEL: 5 to 16 IPM
PREHEAT:	See Attached Sheet	POST HEAT:

BEAD NUMBER	1	2	3	4	5	6	7
ELECTRODE DIAMETER	5/32	5/32	3/16	3/16			
AWS DESIGNATION	A5.1	A5.1	A5.1	A5.1			
VOLTAGE	24-30	24-30	24-30	24-30			
AMPERAGE	90-150	100-175	140-200	140-200			

TENSILE STRENGTH TEST

TEST SPECIMEN NO.	FAILURE LOC. PIPE	WELD	SPECIMEN WIDTH	SPECIMEN THICKNESS	SPECIMEN AREA	POUNDS PULL	TENSILE STRENGTH
T-1	X		1.016	.391	.3972	28,250	71,122
T-2	X		1.044	.385	.4019	29,550	73,525
T-3	X		1.033	.380	.3925	27,250	69,426
T-4	X		1.065	.386	.4110	29,250	71,167

BEND TEST AND NICK BREAK TEST

ROOT OR SIDE BEND SPECIMEN NUMBER	RESULTS	FACE OR SIDE BEND SPECIMEN NUMBER	RESULTS	NICK BREAK SPECIMEN NUMBER	RESULTS	SPECIMEN NUMBER	RESULTS
RB-1	Acceptable	FB-1	Acceptable	NB-1	Acceptable		
RB-2	Acceptable	FB-2	Acceptable	NB-2	Acceptable		
RB-3	Acceptable	FB-3	Acceptable	NB-3	Acceptable		
RB-4	Acceptable	FB-4	Acceptable	NB-4	Acceptable		

☒ PROCEDURE QUALIFICATION ☐ WELDER QUALIFICATION ☐ PRODUCTION WELD TEST
☒ DESTRUCTIVELY TESTED ☐ EXAMINED BY RADIOGRAPHY
☒ QUALIFIED ☐ DISQUALIFIED

QUALIFICATION LIMITATIONS FOR THIS TEST
DIAMETER ☐ LESS THAN 2-3/8" O.D. ☐ 2-3/8" O.D.-12-3/4" O.D. ☒ GREATER THAN 12-3/4" O.D.
WALL THICKNESS ☐ LESS THAN .188" W.T. ☒ .188" W.T.-.750" W.T ☐ GREATER THAN .750" W.T

We certify that the statements of this record are correct and that the test welds were prepared, welded and tested in accordance with the requirements of API 1104 latest approved edition.

WELDING WITNESSED BY Ron Devers	TITLE Duke Energy Insp.	DATE 11-07-02
WELD TESTED BY	FSA TITLE Level III ASNT	DATE 11-07-02
CONTRACTOR	TITLE	DATE 11-07-02

DEC-10-2002 TUE 01:28 PM MURPHY BRO ESTIMATING 13097995159

QCTL

21112 SCOTT PARK ROAD
DAVENPORT, IA 52804

WELDER PROCEDURE NUMBER	TEST REPORT NO	DATE
MANGO Welding Procedure No. 1	N-8628	10-30-02
WELDER		
Paul D. Hoffeller / Gary McDaniel		
SOCIAL SECURITY NUMBER	E46	MARK PDH / GM

WELD TEST REPORT

CONTRACTOR Hoke Construction		JOB #2200 – MB- Ameren Murphy Brothers		
WELDING PROCESS	SMAW	Electrical Characteristics D.C. Reversed Polarity		
PIPE MATERIAL	TYPE: X-52	O.D. 16"	WALL: .375"	MIN. TENSILE: 66,000 PSI
WELDING MACHINE	TYPE: Manual Lincoln 230		SIZE:	
FILLER METAL	GROUP: E-6010	MANUFACTURER: Lincoln		TRADE NAME: 5 P+
JOINT DESIGN	☒ V BEVEL OF 30° ± 5°		☐ OTHER(DESCRIBE)	
POSITION	☐ ROLL	☒ FIXED	☐ HORIZONTAL(2G)	☒ VERTICAL (5G)
DIRECTION	☐ UPHILL		☒ DOWNHILL	
SHIELDING	☐ GAS	☐ FLUX	☐ DESCR:	FLOW RATE:
TIME LAPSE	ROOT BEAD TO SECOND BEAD	Over 24 hours	SPEED OF TRAVEL:	5 to 16 IPM
PREHEAT	See Attached Sheet	POST HEAT:		

BEAD NUMBER	1	2	3	4	5	6	7
ELECTRODE DIAMETER	5/32	5/32	3/16	3/16			
AWS DESIGNATION	A5.1	A5.1	A5.1	A5.1			
VOLTAGE	24-30	24-30	24-30	24-30			
AMPERAGE	90-150	100-175	145-190	140-200			

TENSILE STRENGTH TEST

TEST SPECIMEN NO	FAILURE LOC. PIPE	FAILURE LOC. WELD	SPECIMEN WIDTH	SPECIMEN THICKNESS	SPECIMEN AREA	POUNDS PULL	TENSILE STRENGTH
T-1	X		1.10	.386	.4246	29,900	70,419
T-2	X		1.07	.385	.4119	29,050	70,526
T-3	X		1.04	.380	.3952	28,000	70,850
T-4	X		1.03	.376	.3872	26,850	69,344

BEND TEST AND NICK BREAK TEST

ROOT OR SIDE BEND SPECIMEN NUMBER	RESULTS	FACE OR SIDE BEND SPECIMEN NUMBER	RESULTS	NICK BREAK SPECIMEN NUMBER	RESULTS	SPECIMEN NUMBER	RESULTS
RB-1	Acceptable	FB-1	Acceptable	NB-1	Acceptable		
RB-2	Acceptable	FB-2	Acceptable	NB-2	Acceptable		
RB-3	Acceptable	FB-3	Acceptable	NB-3	Acceptable		
RB-4	Acceptable	FB-4	Acceptable	NB-4	Acceptable		

☒ PROCEDURE QUALIFICATION ☐ WELDER QUALIFICATION ☐ PRODUCTION WELD TEST
☒ DESTRUCTIVELY TESTED ☐ EXAMINED BY RADIOGRAPHY
☒ QUALIFIED ☐ DISQUALIFIED

QUALIFICATION LIMITATIONS FOR THIS TEST
DIAMETER ☐ LESS THAN 2-3/8" O.D. ☐ 2-3/8" O.D.-12-3/4" O.D. ☒ GREATER THAN 12-3/4" O.D.
WALL THICKNESS ☐ LESS THAN 1/8" W.T. ☒ 1/8" W.T.-.750" W.T. ☐ GREATER THAN .750" W.T.

We certify that the statements in this record are correct and that the test welds were prepared, welded and tested in accordance with the requirements of API 1104 latest approved edition.

WELDING WITNESSED BY Ron Devers	TITLE Duke Energy Insp.	DATE
WELD TESTED BY [signature] PSA	TITLE Level III ASNT	DATE 10-30-02
CONTRACTOR Hoke Construction – Darrell Eveland	TITLE	DATE

**REVISED REPORT #2 – ON 11/04/02

PREHEAT

If 5 minutes is exceeded following the root then preheating will be required as follows:

PREHEAT: Preheat shall be required when the ambient or parent metal temperature is below 40°F. The pipe shall be preheated evenly around the pipe circumference. The preheat temperature shall be 260°F for 3" on both sides of the weld. The preheat temperature shall be monitored and controlled before and during welding using a temperature indicating crayon or pyrometer or equivalent device. If moisture is present on the parent metal, it shall be driven off by preheating to a temperature at which it will not re-form before welding is completed.

Enbridge Pipelines (Lakehead) L.L.C.
119 North 25th Street East
Superior, WI 54880-5247
www.enbridgepartners.com

Mark J. Willoughby, Manager
U.S. Compliance & Risk Management
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

May 5, 2004

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2004-1007

Dear Mr. Huntoon:

Pursuant to the above noted Office of Pipeline Safety (OPS) Notice of Probable Violation and Proposed Civil Penalty issued April 5, 2004, Enbridge requests that you consider the following responses to reduce or eliminate the potential fines where appropriate:

1. **§ 192.225 Welding – General**

§ 192.225(b) requires that each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

Enbridge failed to have qualified welding procedures for the construction of the Crete Meter Station project.

The meter station was put into service in early 2002, however, Enbridge personnel were unable to show the destructive qualifying tests for the Mango No. 1 procedure used during this project. As a result, Enbridge qualified the procedure in October 2002, after the project was completed and in operation.

Response to Item #1:
On November 26, 2001, two welders working for Murphy Brothers were successfully qualified utilizing the Mango procedure: Rodney Pilgreen S.S. # 430-33-9585 - 16 straps were destructively tested and Robert Stewart S.S. # 356-62-0119 - 12 straps were destructively tested. Both welders completed one half of the weld simultaneously. Based on the total of 28 straps tested, the revised Mango procedure was qualified and all subsequent production welds on the Crete Lateral were completed within the parameters of the procedure.

Enbridge re-wrote the revised Mango procedure that was qualified on November 26, 2001 using the current Enbridge standardized forms and numbering system (Enbridge WPS 65, attached), based upon the qualification record from November 26, 2001. We regret that this information was not readily available during your investigations, however, the documentation provided substantiates that our welding procedure and subsequent production welds are in compliance. Based on the documentation presented, Enbridge requests that the probable violation be reconsidered and the imposed penalty be removed.

2. **§ 192.465 External Corrosion control: Monitoring.**

§192.465(b) requires that the operator inspect each cathodic protection rectifier or other impressed current power source six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.

Enbridge failed to inspect three (3) rectifiers between September 20, 2001 and February 20, 2002.

The three (3) rectifiers were located at M/L Valves 3, 5, and 18. There was a five (5) month interval between the readings.

Response to Item #2:
Contract personnel installed the rectifiers during construction, but their installation and activation were not reported to operations personnel. Enbridge identified this deficiency prior to the audit. The rectifiers have been read according to regulatory requirements since their discovery, as was indicated during the audit.

3. **§192.706 Transmission lines: Leakage surveys.**

§192.706(a) requires the operator to conduct leakage surveys of a transmission line at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted-

(a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year

The Company failed to conduct two leak surveys within the calendar year at the class three locations in Illinois and Indiana.

One survey was done on 7/12/01, and the second survey was done on 1/2/02.

In addition, at the class three location in Michigan, one survey was done on 12/31/01, and the next was done on 8/22/02. This exceeded the 7 ½ month criteria.

Response to Item #3:
The pipeline crews charged with conducting these surveys misunderstood the required time lines for completion. They are now aware of the necessity of meeting the required time lines and have successfully done so since this error occurred.

4. **§192.731 Compressor stations: Inspection and testing of relief devices.**

§192.731(a) requires each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

At the Springville Compressor station, Enbridge did not inspect two relief valves for 2001 and 2002.

The two relief valves, PSV 108 and 208, are thermal relief valves on the compressor recycle loop. The relief valves had not been inspected since their installation in 2000. Your personnel stated that this was an over-sight.

Response to Item #4:
Enbridge does not dispute that, due to our oversight, the indicated thermal relief valves PSV's 108 and 208 were not inspected in 2001. Upon discovery of our error by the OPS auditor on or about September 4, 2002, the valves were inspected and the paperwork received within one day. The attached document, Form 2030-1 for Springville dated 10-2-02, demonstrates that the valves were inspected and tested in 2002. Since the valves were successfully tested in 2002, we ask that OPS reconsider this item and recognize the 2002 documentation.

5. **§192.743 Pressure limiting and regulating stations: Testing of relief devices.**

§192.743(b) requires the operator to review and calculate the required capacity of the relieving device at each station at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities should be compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

Enbridge failed to conduct an annual review of the capacity calculations for the relief at the Alliance/Northern Border interconnect and for the two relief valves at the Springville Compressor Station.

At the Alliance/Northern Border interconnect, the capacity of the relief valve at that location was not checked in 2001. In addition, at the Springville Compressor station, PSV 108 and 208 did not have their capacities checked in 2001 and 2002.

Response to Item #5:
Although yearly calculations of relief capacities were not documented in 2001 and 2002, Enbridge is confident that relief capacities were adequate since no changes to the facilities or operating capacities occurred. The only pressure relief device at the Alliance/Northern Border meter station is AL726-PSV-003, which is on the SPU fuel line. The attached document, Form 2030-1 for Alliance/Northern Border dated 11-29-01 demonstrates that this device was checked in 2001. While the tag description is incomplete, the physical description, indicated set point and the testimony to me by one of the technicians who performed the check, should serve to validate the record.

Attached is Enbridge's Operator Qualification procedure for Gas Technicians which applies to the capacity issue. Enbridge has added a requirement to this document to verify that the devices and systems have not been altered or changed. While it has not been a part of the written procedure, the technical staff performing these checks has always been instructed to verify that the devices and systems have not changed. Enbridge can prove that these devices and systems have not changed since original design and construction. We have improved our reporting for this issue and will continue to do so. Also attached is an example of the field data sheets now being used (2004) to verify relief valve capacities. With regard to the above, we request your reconsideration of the proposed civil penalty.

In conclusion, Enbridge is committed to working with the OPS to ensure full regulatory compliance and safety to the public and environment. We view all violations very seriously and act promptly and responsibly in correcting them or, as is the case with some of the items listed above, ensuring that the OPS has a clear understanding of each situation. We request that the items listed above be reviewed and, where requested, and the civil penalties reconsidered. Enbridge also wishes to reserve our right to a hearing if an agreement cannot be met on reduction of civil penalties.

Sincerely,

Mark J. Willoughby

Mark J. Willoughby

Attachments

c: Craig Fishbeck
Steve Irving
Tom Fridel
Greg Sevick
Dan Tutcher

Enbridge Energy

Weld Procedure Specification API 1104 18th Edition

Procedure No: WP 65
Procedure Type: Butt Weld

Note: Shaded headings and starred numbers denote essential variables

Electrode Group: GP1 (E6010) AWS Spec. A5.1	Weld Process: Shielded Metal Arc Welding	Material Group: X46 and X52
Diameter Group: Greater than 12.75 in. OD	Wall Thickness Group: 0.188 in. - 0.750 in. WT	

Test Pipe Data

Diameter:	Wall Thickness:	Grade:	Manufacturer:
16 in.	0.312 in.	API 5L X52	U.S. Steel Heat F20234

*AWS Class No. only becomes an essential variable on pipe grades X56 and greater

Bead Parameters

K - Joules = (AMPS)(VOLTS)(60) / (Speed of Travel)(1000)

Bead Number	Electrode Size	Electrode Group No.	*AWS Class No.	Electrode Type	Electrode MFG	Curr. Range (Amps)	Volt Range (Volts)	[illegible]	[illegible]	Heat input range (K-Joules)
1	1/8 in.	1	A5.1	E6010	Lincoln	58-105	22-27	15	6-9	15-18
2	5/32 in.	1	A5.1	E6010	Lincoln	100-135	24-27	10	7-11	18-24
3	3/16 in.	1	A5.1	E6010	Lincoln	145-163	25-29	10	6-9	27-42
4	3/16 in.	1	A5.1	E6010	Lincoln	156-180	25-29	-	7-9	30-39

Tensile Strength Data

Specimen No.	Failure Location Pipe	Failure Location Weld	Specimen Width (in.)	Specimen Thickness (in.)	Specimen Area (in2)	Pounds Pull	Tensile Strength (psi)
Tensile 1	X		0.975	0.312	0.304	23705	77926
Tensile 2	X		1.015	0.312	0.317	24305	76749
Tensile 3	X		0.987	0.312	0.308	24399	79232
Tensile 4	X		1.025	0.312	0.320	24526	76689

Bend and Nick Break Test Data

Root or Side Bend Specimen	Results	Face or Side Bend Specimen No.	Results	Nick Break Specimen No.	Results
Root 1	OK	Face 1	OK	Nick Break 1	OK
Root 2	OK	Face 2	OK	Nick Break 2	OK
Root 3	OK	Face 3	OK	Nick Break 3	OK
Root 4	OK	Face 4	OK	Nick Break 4	OK

WELD MEETS VISUAL INSPECTION: YES: X NO: ____
MECHANICAL RESULTS: ACCEPTABLE: X UNACCEPTABLE: ____
RADIOGRAPHICAL TEST RESULTS: ACCEPTABLE ____ UNACCEPTABLE ____

Process Parameters

No. of welders: 2 1st & 2nd beads: 2 Remaining beads: 2

Welders Names: Rodney Pilgreen SS # On File; Robert Stewart SS # On File

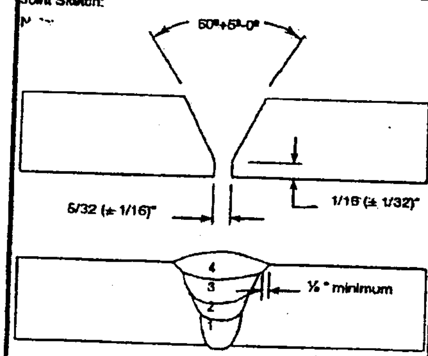
Cleaning Information:
Root Bead: Hot Pass Beads: Remaining Beads:
Grind or power brush to clean metal for all beads, as required

[illegible]: Vertical Down
[illegible]: Fixed

Line Up Clamp: Internal: External:

Removal of lineup clamp - Percent
Internal: External:

Joint Sketch:



[illegible]: Not Applicable

[illegible]:
X DC Reverse (Rod Positive) ____ DC Straight (Rod Negative)

Type and Size of Welding Machine: Lincoln 250 Amp

Total Time: 45 minutes
Preheat Temperature: 50 °F Minimum Temperature
Stress Relief Temperature: Not applicable

Ambient Temperature: 50 °F
Windbreak Used: No

Precipitation: None, Partly Cloudy
Inside or Outside Building: Outside

Job Site: Enbridge Energy Crete Lateral

Contractor: Murphy Brothers

: When this form is used to qualify a procedure, the original Welding Data and Mechanical Test Data worksheets must accompany the completed form.

Prepared By: Robert Lazor, BMT Fleet Technology Limited Title: Date: 11/26/2001

Approved By: Signature: B. Shoultz [signature] Title: Proj. Manager Date: 11/26/01

Remarks:

16" SMAW

		Amps	Volts	inches Per minute
1/8"	1	68-90	22-26	6-7
5/32	2	100-130	24-27	7-11
3/16	3	148-160	25-29	6-9
3/16	4	156-180	25-29	7-9

Root

1 .312 wall x 1.10 wide ok
2 .312 wall x .979 wide ok
3 .312 wall x .995 wide ok
4 .312 wall x .989 wide ok

Face

1 .312 wall x .988 wide ok
2 .312 wall x .975 wide ok
3 .312 wall x .985 wide ok
4 .312 wall x 1.12 wide ok

Nicks

1 .312 wall x .987 wide ok
2 .312 wall x .998 wide ok
3 .312 wall x .986 wide ok
4 .312 wall x .997 wide ok

Tensil

1 .312 wall x .975 wide break at 23705
2 .312 wall x 1.015 wide break at 20305
3 .312 wall x .987 wide break at 24399
4 .312 wall x 1.025 wide break at 24525

1 G Fixed Position

welder Rodney Pillgreen 55#

16" SMAW

		Amps	Volts	inches Per minute
1/8"	1	70-105	23-27	6-9
5/32"	2	110-135	24-27	7-11
3/16"	3	145-167	25-28	6-9
3/16"	4	160-180	26-29	7-9

Root

1 .312 wall x .997 wide ok.

2 .312 wall x .956 wide ok

Face

1 .312 wall x .950 wide ok

2 .312 wall x .987 wide ok

sides

1 .312 wall x .964 wide ok

2 .313 wall x .995 wide ok

3 .312 wall x 1.026 wide ok

4 .312 wall x .987 wide ok

Tensil

1 .312 wall x .996 wide break at 24302

2 .312 wall x .950 wide break at 24632

3 .312 wall x .994 wide break at 24562

4 .312 wall x .979 wide break at 24792

16 fixed Position

welder Robert Stewart 55#

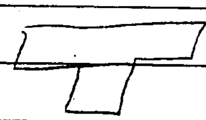
12 3/4 Branch on 12 3/4 Pipe

	Amps	Volts	inches per minute
1	75-90	23-26	5-7
2	100-112	26-29	8-10
3	140-148	27-29	6-7
4	145-153	28-30	7-8
5	150-165	28-30	7-10
6	151-167	28-30	7-10
7	150-169	27-30	7-10

Breaks

1 .354 wall x 1.025 wide ok
2 .354 wall x .997 wide ok
3 .354 wall x .935 wide ok
4 .354 wall x .905 wide ok

1G Fixed



welder Rodney PilGreen 55# 846

ENBRIDGE

Over Pressure Protection Devices

Form 2030-1

Location: SPRINGVILLE

Device ID	Description	As Found	As Left	Date
806-PSV-003	STATION Suction PRESSURE Relief	993	993	10-2-02
	SET @ 1000 psi			
	CAPACITY OK			
1 PSV ~~008~~ 108	Unit 1 RECYCLE VALVE RELIEF	1325	1325	
	SET AT 1330 psi			
	CAPACITY OK			
1 PSV 208	Unit 2 RECYCLE Valve Relief	1328	1328	
	SET AT 1330 psi.			
	CAPACITY OK			
715 PSV 104	Unit 1 Fuel PRESSURE Relief	531	531	
	SET @ 540 psi			
	CAPACITY OK			
715 PSV 204	Unit 2 Fuel PRESSURE Relief	538	538	
	SET @ 540 psi			
	CAPACITY OK			

Remarks: All RELIEF VALVES TESTED with NITROGEN SOURCE PRESSURE.

Checked By: [signature] 3/25/03

ENBRIDGE

Over Pressure Protection Devices

Form 2030-1

Location: ALLIANCE/NORTHERN BORDER

Device ID	Description		As Found	As Left	Date
AL726-PI-001	SPU PRESSURE	0	0.1	0.1	~~[illegible]~~
		25	25.1	25.1	" 11-29-01
		50	49.9	49.9	"
		75	75.2	75.2	"
		100	100.1	100.1	"
AL726-	SPU RELIEF VALVE				"
	SET POINT = 40		40	40	"

NOTE
AL726-PSV-001
(JR)
4-17-03

DONE
11-29-01
(JR)

Remarks:

Checked By: Jim Reno / Tom Smith

Operator Qualification Procedure – Gas Technician

Overpressure protection, relief and regulator device maintenance

- Identify device to be maintained
- Test device
  - Test in place where practical
  - If necessary to remove from system for testing, test should reflect actual operating conditions a closely as possible
  - Visually inspect device in place and verify capacity if device cannot be tested or removed
- Demonstrate proper operation of non-relieving type overpressure protection device
  - Transducer type device
  - Calibrate the transducer
  - Verify correct software set point
  - Observe device while bringing process or test pressure up to the set point
  - Operate or verify operation of control loop if practical
- Mechanical (non-transducer) type device
  - Observe device while bringing process or test pressure up to the set point
  - Verify that device reacts in the desired manner
- Demonstrate proper operation of relieving type overpressure protection device
- Verify that device has not been altered or changed and that the system which the device is designed to protect has not been altered or changed.
  - Observe device while bringing pressure up to set point
  - Verify that device activates at proper set point
- Re-calibrate, re-set set point, repair or replace device as needed
- Verify each device is tagged with proper identification and current set point
- Document on proper form

Vector Pipeline - Pressure Relief Valve Capacity Verification Form

Valve Tag No.:	AL-726-PSV-003	
P&ID No.:	D-1-3.704-0102-1-10	
Service:	SPU Gas Letdown Pressure Relief	
Nozzle:	Full	
Design Type:	Safety-Relief/Conventional	
Bonnet Type:	Integral	
Required Relief Load Capacity:	9042	SCFH
Operating Pressure:	40	p.s.i.g.
Set Pressure:	60	p.s.i.g.
Operating Temp.:	45	°F
Allowable Overpressure:	10	%
Design Code:	ASME	
Sizing Basis:	Relief	
Calculated Area:	0.09235	in.^{2}
Selected Area:	0.125	in.^{2}
Orifice Designation:	D	
Inlet/Outlet Size:	0.75/1	in.
Inlet Flange Rating/Facing:	MNPT	
Outlet Flange Rating/Facing:	FNPT	
Body & Bonnet Material:	316SS/CS	
Seat & Ring Material:	Buna N/316SS	
Resilient Seat Seal Material:	N/A	
Guide & Ring Material:	316SS	
Spring Material:	Chrome Alloy	
Bellows Material:	N/A	
Manufacturer:	Farris	
Model No.:	27DC23-M20	
Serial No.:	426255-1-KE	
Capacity of pressure relief valve:	13393.8 SCFH	

Has there been any change(s) in: Pressure Relief Valve: ☐ YES ☐ NO

System: ☐ YES ☐ NO

Comments:

Form completed by:

PRINTED NAME TITLE

SIGNATURE DATE

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

February 11, 2005

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2004-1007

Dear Mr. Huntoon:

Pursuant to the above mentioned Office of Pipeline Safety (OPS) Notice of Probable Violation and Proposed Civil Penalty, and based on a recent phone conversation with Carl Griffith, Enbridge believes that the issues can be resolved by working with the Central Region OPS and therefore waives the right to a hearing regarding these issues. We respectfully reaffirm our request that the items identified be reviewed in consideration of our responses. We also ask that OPS consider reducing or eliminating potential fines.

Sincerely,

Mark Willoughby

c: Craig Fishbeck
Tom Fridel
Steve Irving
Art Meyer
Dan Tutcher

7

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

FEB 16

Mr. Dan Tutcher
President
Enbridge Energy, Limited Partnership
1100 Louisiana, Suite 2950
Houston, TX 77002

Re: CPF No. 3-2004-1007

Dear Mr. Tutcher:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It withdraws one of the allegations of violation, makes findings of violation, and assesses a civil penalty of $5,000. The penalty payment terms are set forth in the Final Order. This enforcement action closes automatically upon payment. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: Mr. Ivan Huntoon
Director, Central Region, OPS

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Enbridge Energy Limited Partnership,	)	**CPF No. 3-2004-1007**
	)	
Respondent.	)	

FINAL ORDER

On September 3-6, 2002, October 15-16, 2002, and March 10-11, 2003, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Michigan Public Service Commission conducted an on-site pipeline safety inspection of Respondent's Vector pipeline facilities and records in Illinois, Indiana, and Michigan. As a result of the inspection, the Director, Central Region, PHMSA, issued to Respondent, by letter dated April 5, 2004, a Notice of Probable Violation and Proposed Civil Penalty (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had committed violations of 49 C.F.R. Part 192 and proposed assessing a civil penalty of $11,500 for the alleged violations.

Respondent responded to the Notice by letter dated May 5, 2004, as supplemented by letter dated February 11, 2005 (Response). Respondent contested the allegations in part, offered information to explain the allegations, described the corrective measures it has taken, and requested that the proposed civil penalty be reduced or eliminated. Respondent did not request a hearing, and therefore has waived its right to one.

FINDINGS OF VIOLATION

Item 4 in the Notice alleged that Respondent violated 49 C.F.R. § 192.731(a) by failing to demonstrate that relief valves PSV-108 and PSV-208 were inspected in 2001 or 2002. In its response, Respondent provided documentation demonstrating that the specified valves were inspected in 2002, but acknowledged that the valves were not inspected in 2001. Accordingly, I find that Respondent violated § 192.731(a) by failing to inspect the specified relief valves in 2001.

Item 5 in the Notice alleged that Respondent violated 49 C.F.R. § 192.743 by failing to demonstrate that yearly review and calculations of relief capacities were conducted for relief valves PSV-003, PSV-108, and PSV-208 in 2001 or 2002. In its response, Respondent provided documentation demonstrating that PSV-003 had been checked for set point in 2001, but acknowledged that yearly calculations of relief capacities for the specified valves were not documented in 2001 and 2002. Accordingly, I find that Respondent violated § 192.743 by failing to demonstrate that yearly review and calculations of relief capacities were conducted for the specified relief valves in 2001 or 2002.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

WITHDRAWAL OF ALLEGATION

Item 1 in the Notice alleged that Respondent violated 49 C.F.R. § 192.225(b) by failing to demonstrate that a welding procedure used for the Crete Lateral construction project had been qualified by appropriate tests. In its response, Respondent submitted information demonstrating that it did have a qualified welding procedure in place at the time of the construction. Based on this information demonstrating compliance with the regulation, I am withdrawing this allegation of violation.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $25,000 per violation for each day of the violation up to a maximum of $500,000 for any related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require.

With respect to Item 4, the Notice proposed a civil penalty of $3,000 for Respondent's failure to demonstrate that pressure relief valves PSV-108 and PSV-208 were timely inspected. Annual inspection and testing of relief devices is an important part of pipeline safety because their operability must be periodically verified in order to ensure protection against potential overpressure events. In its response, Respondent explained that its failure to inspect the specified valves in 2001 was an oversight, and demonstrated that it did in fact inspect the specified valves in 2002. Based on this information demonstrating compliance with the applicable regulation in one of the two years cited, a reduction of 50 percent in the civil penalty amount proposed in the Notice for this item is warranted. Accordingly, I assess Respondent a civil penalty of $1,500 for violating 49 C.F.R. § 192.731(a).

With respect to Item 5, the Notice proposed a civil penalty of $3,500 for Respondent's failure to demonstrate that yearly review and calculations of relief capacities were conducted for the specified relief valves in 2001 or 2002. Annual review and calculations of relief valve capacities is an important part of pipeline safety because the sufficiency of their capacity to limit the operating pressure to the desired maximum must be periodically verified in order to prevent potential overpressure events from causing damage. In its response, Respondent explained that it had reason to believe that the relief capacities of the specified valves were sufficient during the relevant period. Respondent, however, has presented no information that would warrant a reduction in the civil penalty amount proposed in the Notice for this violation. Accordingly, I assess Respondent a civil penalty of $3,500 for violating 49 C.F.R. § 192.743.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of $5,000.

Payment of the civil penalty must be made within 20 days of service. Payment may be made by sending a certified check or money order (containing the CPF Number for this case) payable to "U.S. Department of Transportation" to the Federal Aviation Administration, Mike Monroney Aeronautical Center, Financial Operations Division (AMZ-120), P.O. Box 25082, Oklahoma City, OK 73125.

Federal regulations (49 C.F.R. § 89.21(b)(3)) also permit this payment to be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-120), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-4719.

Failure to pay the $5,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

WARNING ITEMS

The Notice did not propose a civil penalty or compliance order for Items 2 and 3 in the Notice. Therefore, these are considered to be warning items. The warnings were for Respondent's failure to timely inspect three rectifiers in accordance with § 192.465(b); and failure to timely conduct leak surveys at three locations in accordance with § 192.706(a). Respondent is warned that if these items are not addressed, enforcement action will be taken if a subsequent inspection reveals a violation.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a petition for reconsideration of this Final Order. Should Respondent elect to do so, the petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of a petition automatically stays the payment of any civil penalty assessed. However if Respondent submits payment for the civil penalty, the Final Order becomes the final administrative decision and the right to petition for reconsideration is waived. The terms and conditions of this Final Order are effective on receipt.

for

Stacey Gerard
Associate Administrator
for Pipeline Safety

FEB 16 [illegible]

Date Issued

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U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 26, 2004

Mr. Dan Tutcher
President
Enbridge Energy, Limited Partnership
1100 Louisiana
Suite 2950
Houston, TX 77002

CPF No. 3-2004-5009

Dear Mr. Tutcher,

On February 19, 2004, a representative of the Minnesota Office of Pipeline Safety (MN-OPS), pursuant to Chapter 601 of 49 United States Code, conducted an investigation of a leak on Enbridge Energy, LP's (Enbridge) 26" Line #2 in Grand Rapids, MN.

As a result of the investigation, it appears that you have committed a probable violation, as noted below, of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The item inspected and the probable violation is:

1) **§ 195.52 - Telephonic notice of certain accidents.**

§ 195.52(a) requires the operator to report to the National Response Center (NRC) at the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in §195.50, the operator of the system shall give notice, in accordance with paragraph (b) of this section, of any failure that:

(1) Caused a death or a injury requiring hospitalization;
(2) Resulted in either a fire or explosion not intentionally set by the operator;
(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;
(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

Enbridge failed to report to the National Response Center (NRC), at the earliest practicable moment, the leak on the 26" Line #2.

On February 19, 2004, Enbridge personnel discovered a small leak on the 26" Line #2 in Grand Rapids, MN. The leak was found while conducting an excavation for an internal inspection indication at MP 1007.33. Further investigation revealed that the leak was due to a crack within a dent, on the bottom of the pipe.

On March 2, 2004, a telephonic report regarding this leak was made to the NRC. This was approximately 12 days after the leak was discovered.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in the above probable violation cited and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

Please refer to CPF No. 3-2004-5009 in any correspondence or communication on this matter.

Sincerely,

Donald E. Moore
for Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

(1)

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 20, 2004

Mr. Mark Willoughby
Manager, US Compliance & Risk Management
Enbridge Energy Company Inc.
119 N. 25th Street
Superior, WI 54880-5427

CPF No. 3-2004-5029M

Dear Mr. Willoughby:

On July 28-29, 2004, representatives of the Office of Pipeline Safety (OPS), and the Minnesota Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your Operator Qualification (OQ) records and procedures at your headquarters in Superior, Wisconsin.

As a result of the inspection, it appears that the Enbridge Energy Company Inc. (Enbridge) written OQ plan does not comply with the pipeline safety regulations located at Title 49, Code of Federal Regulations (CFR), Part 195. The team review of Enbridge's OQ Plan revealed that further development of the plan is necessary. The items inspected and the probable violations are:

1. **§195.505 Qualification Program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   (a) Identify covered tasks;

   Enbridge did not identify a general pipe fitting task (or subtask), which should be added to address the use of tubing and small piping during maintenance.

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;

Enbridge does not address whether an individual would be allowed to continue performing the covered task(s) until the investigation is complete. The statement should be revised to specify that the individual's qualification(s) for the task(s) will be suspended immediately after an incident, if the operator has reason to believe that the individual's performance was contributory.

(f) Communicate changes that affect covered tasks to individual performing those covered tasks.

Enbridge's written plan addressed future changes and the communication needed to notify all individuals with the need to know. Enbridge should expand the management of change section for additional clarification of personnel responsibilities. The flowcharts given to the inspection team should be imbedded into the plan to provide guidance about the program and its requirements.

In regard to the items above, when it is found that an operator's procedures are inadequate, §195.402(b) provides that the operator, after notice and opportunity for hearing, as provided in 49 C.F.R. §190.237, may be required to amend its plans and procedures. This letter serves to provide you with that notice of inadequate procedures and response options, as prescribed under §190.237. The operator is allowed thirty (30) days after receipt of such notice to submit written comments or to request an informal hearing. After considering the material presented, the Office of Pipeline Safety is required to notify the operator of the required amendment or to withdraw the notice proposing the amendment. If you do not desire to contest the notice, you must prepare the revised procedures and provide a copy to the Director, Central Region, within thirty (30) days of receipt of this notice.

Please refer to CPF No. 3-2004-5029M for any correspondence on this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

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ENBRIDGE™

October 19, 2004

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2004-5029M

Dear Mr. Huntoon:

This submittal is in response to your "Notice of Amendment" sent to this office dated September 20, 2004. Your letter identified three issues resulting from a review of our Operator Qualification (OQ) records and procedures during an on site audit in Superior, Wisconsin in July of 2004. Enbridge is a responsible operator, and we value the opportunity to address these items. We also appreciate the working relationship demonstrated by this approach. Below are the specific items that were identified, and our response to each item, respectively:

1. **§195.505 Qualification Program.**

   (a) Identify covered tasks;
   Enbridge is in the process of adding a general pipe fitting task for tubing and small piping. Once the final edits are made the procedure will be added to the Performance Based Training and OQ databases.

   (b) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;
   Enbridge's OQ plan (attached) has been updated to address this issue. In addition, a post-incident flowchart (Appendix D) has been added to the plan to further demonstrate the process.

   (c) Communicate changes that affect covered tasks to individuals performing those covered tasks.
   A new "Change Management" section has been added to the plan. In addition, the flow chart "Change Management Methodology" (Appendix F) and a Change Management Form (Appendix G) have been added to the plan.

I trust that these explanations and proposed actions, along with the updated OQ plan, have addressed the concerns outlined in your letter. Should you have any further questions or concerns, please feel free to contact me at (715) 394-1534.

Sincerely,

Mark Willoughby

Mark Willoughby

Attachments
c: Steve Irving
Art Meyer
Leisa Doberstein
Boyd Haugrose

DOT Operator Qualification Plan

In compliance with

Subpart G in 49 CFR Part 195
Subpart N in 49 CFR Part 192

Enbridge Energy, Limited Partnership
Enbridge Pipelines (North Dakota) LLC
Enbridge Pipelines (Toledo) Inc.
Vector Pipeline L.P.

Administrator
Leisa D. Doberstein

TABLE OF CONTENTS

INTRODUCTION

- This Operator Qualification Plan is designed to demonstrate compliance with governmental regulation by ensuring a qualified workforce and instituting procedures that aid in reducing the probability and consequence of incidents caused by human error.
  - Regular company policies and procedures remain in place.

- This Plan covers only the following pipeline companies/systems operated by U.S. Enbridge affiliates (hereafter Enbridge US).

  Enbridge Energy, Limited Partnership
  Enbridge Pipelines (North Dakota) LLC
  Enbridge Pipelines (Toledo) Inc.
  Vector Pipeline L.P.

- This Operator Qualification Plan includes all individuals who perform covered tasks while operating and/or maintaining pipeline facilities on behalf of Enbridge US and intends to verify the capability of these individuals to operate and maintain the pipeline.
  - This compliance plan was established April 27, 2001, is currently in effect and will continue to evolve as needed.
  - All individuals performing covered tasks after October 28, 2002 will be qualified or supervised by a qualified individual.

RESPONSIBILITIES

- Operator Qualification Steering Committee
  - Oversee Operator Qualification process.
  - Review and update Operator Qualification Plan.
  - Review and update covered task lists.
  - Communicate significant changes as needed
  - Monitor plan performance through yearly audits.

- Administrator
  - Oversee Operator Qualification process.
  - Review and update Operator Qualification Plan.
  - Review, update covered task lists.
  - Document changes to the Operator Qualification Plan and covered task lists.
  - Chair Operator Qualification Steering Committee meetings.
  - Communicate significant changes as needed.
  - Periodically monitor the evaluators' entries in the DOT Operator Qualification Database to track progress and ensure proper compliance

- Manager
  - Ensure all necessary qualifications are completed.
  - Communicate and reinforce the company's obligation to perform evaluations in compliance with DOT.
  - Periodically monitor the evaluators' entries in the DOT Operator Qualification Database to track progress and ensure proper compliance.

- Evaluator/Supervisor
  - Observe and evaluate employee performance of covered tasks.
  - Document qualification information in database.
  - Monitor employee performance and provide training as necessary.
  - Ensure a qualified individual is assigned to any non-qualified worker performing covered tasks.
  - Ensure all employees new to their area are qualified to perform the appropriate covered tasks.
  - Designate an evaluator, with job specific knowledge, to assist in the evaluation of individuals and tasks, when necessary.

- Individual
  - Become fully qualified in appropriate covered tasks.
  - Oversee the performance of covered tasks by those not qualified upon request.

- Project Manager
  - Understand the Company Operator Qualification Plan.
  - Include a listing of applicable covered tasks in project specifications.
  - Ascertain the qualification of contract workers prior to awarding the contract/commencement of work.
  - Ensure that a qualified contract worker is present to oversee the performance of any covered task performed by any non-qualified contract personnel.

- Contractor
  - Understand and comply with the Enbridge US Operator Qualification Plan.
  - Ensure workers employed to perform covered tasks on the Enbridge US system are properly qualified or supervised by a qualified worker.
  - Provide documentation to the Enbridge US indicating required qualification information.

INITIAL IDENTIFICATION OF COVERED TASKS

- The Enbridge US Operator Qualification Steering Committee, composed of representatives from various Operations disciplines, completed the identification of covered tasks and the preparation of this Plan.

- Task outlines and procedures have been written using a combination of knowledge gathered from experienced employees, Company manuals, industry standards, regulatory requirements and manufacturer's recommendations.

- The Operator Qualification Process and Performance Based Training Manual contain complete job task outlines.

- Where Company task outlines had not yet been established, covered tasks were adapted from industry standard.

- Task outlines and procedures were reviewed and evaluated using the following four-part criteria:
  - Is performed as a requirement of 49 CFR Part 195 or 192
  - Is an operations or maintenance task
  - Is performed on a pipeline facility
  - Affects the operation or integrity of the pipeline

- Covered tasks, for the purpose of Operator Qualification, are those operations tasks meeting all four criteria.

- The Covered Task Chart in Appendix A lists the tasks to be included as covered tasks for Enbridge US.

ENBRIDGE US EVALUATION PROCESS

Evaluation

- The standard of acceptable performance for satisfactory qualification will be the Enbridge US Company procedures for that task found in PBT Job Task Outlines, Maximo Job Plans, site specific guidelines and/or manufacturers' instructions.

- Evaluation of an individual's ability to perform a covered task is primarily determined by an evaluator utilizing a verbal review of task procedures and to the greatest extent possible observation of task performance/simulation.

1) **Verbal review of task procedures**
   A verbal review of task procedures is required in all instances.

2) **Observation of task performance/simulation**
   Qualification activities will be incorporated into the daily operations of the work area as much as possible. Justification for not observing task performance must be documented on the DOT Operator Qualification database.

- The Evaluator, as a part of evaluation, will conduct a discussion ensuring compliance with Subpart G Part 195 and/or Subpart N Part 192, regarding the individual's ability to recognize and react to abnormal operating conditions that may occur while performing the identified covered tasks.
    - Abnormal operating conditions may include any indication of a malfunction of a component or deviation from normal operations that may indicate a condition exceeding design limits or result in a hazard to persons, property or the environment.
    - Evaluators are supplied with structured questions/scenarios on each covered task around which they will conduct the discussion regarding abnormal operating conditions.
    - An initial list of Abnormal operating condition examples found in Appendix C are intended to assist the evaluator by providing examples of abnormal operating conditions relating to the individual covered task. The evaluator may create additional questions specific to the evaluation situation.

- The employee may:
    - Review procedures prior to qualification.
    - Request a different evaluator if there is reason to believe the original evaluator lacked objectivity during the evaluation.

Evaluator

- The supervisor is responsible for ensuring compliance with Subpart G in 49 CFR Part 195 and/or Subpart N in CFR Part 192 and will normally act as an evaluator in performing evaluations.

- In cases where it may be impractical for the supervisor to complete all the required evaluations, the supervisor may designate an evaluator, with job specific knowledge, to assist in the evaluation of individuals and tasks.

- To qualify as an evaluator, an Enbridge US employee must :
    - Demonstrate appropriate interpersonal skills.
    - Be endorsed by management.
    - Possess knowledge of the task.
    - Complete evaluator training session

- To fulfill evaluation duties, an evaluator must:
  - Assess the individual's understanding of and ability to perform a covered task based upon the performance standard of proper procedure.
  - Determine the individual's understanding of and ability to recognize and appropriately react to abnormal operating conditions.
  - Document the individual's ability to perform a covered task.

OPERATOR QUALIFICATION GUIDELINES

Enbridge US Employee Training Process

- The Performance Based Training (PBT) Process, where implemented, will continue to be used for documenting the learning of job specific tasks by employees new to their position.
  - PBT is a progressive learning process used by the Company since 1993 to train employees learning a new job.
  - Learning is documented at three levels of attainment, with Level 1 indicating satisfactory independent performance of the task.
  - Non-qualified individuals will be evaluated on covered tasks when they have attained a Progress Status of Level 1 as documented in the Performance Based Training Process.

Use of Non-qualified Individuals

- Non-qualified individuals may perform covered tasks when directed and observed by a qualified individual who will ensure immediate corrective action is taken when necessary.

- Qualified individuals overseeing non-qualified workers are responsible for the correct and safe performance of the covered task(s).

- Non-qualified workers may be used with the ratio not to exceed two non-qualified workers to one qualified worker.

- When performing one or more covered tasks for Enbridge US, non-qualified workers must become operator qualified within the first five days of performing each covered task.

- Only qualified individuals may perform the following tasks
  - Non-Destructive Testing – ASNT Certification and AOC Test required
  - Tank Inspection – API 653 Certification required
  - Welding – Company specific welding procedure test and AOC required

Required Re-evaluation after Qualification

- If an individual is involved in a DOT reportable incident while performing a covered task the individual must immediately be prohibited from independent performance of the identified covered task until re-qualified unless there is evidence that the task was performed properly.

- The Post Incident Process flowchart in Appendix D illustrates the action taken by the supervisor should an incident occur.

- An individual who may no longer be qualified to perform a covered task will be re-evaluated on that covered task. Such re-evaluation might take place in circumstances where the individual has:
  - Displayed unsatisfactory performance
  - Acquired physical/mental limitations
  - Been away from the work place for 6 months or more.
    Or
  - The task procedure has been significantly re-written.

- After initial qualification, subsequent re-qualifications for all individuals must occur within three years to the date of the last qualification.

Operator Qualification Process Review and Update

- Covered tasks will be reviewed, updated and communicated by the Operator Qualification Steering Committee or administrator as changes occur.

Such changes may include:
  - Installation of new equipment or technology requiring procedural change
  - Modification of a pipeline facility impacting a covered task
  - Regulatory change
  - Company policy or procedure change.

- The Operator Qualification Process will be reviewed on a yearly basis and updated as necessary.

EMERGENCY RESPONSE

- All Enbridge US employees will be qualified in tasks they normally perform and are trained annually in emergency response.

- As a first responder, all Enbridge US field employees are qualified to operate remote valves under the direction of the Control Center as well as direct non-qualified individuals as necessary.

CONTRACTOR QUALIFICATION GUIDELINES

- Contractors engaged to perform covered work after October 28, 2002 on facilities subject to this Plan must comply with the Enbridge US Operator Qualification Plan.

- Documentation of compliance must be provided to Enbridge US prior to commencing the covered work, kept current for the duration of the work and be retained for five years.

- Contractors may satisfy qualification requirements by one of the following methods:
  - Documentary evidence of contractor qualification of employees via observation of performance, verbal review of task procedure or written test pursuant to applicable regulations.
  - Operator approved third-party vendor qualification.

- Contract workers may be qualified and documented by the same method stated herein for Enbridge US employees in special circumstances.

Contractor Documentary Evidence of Qualification

- Companies who contract to supply 24-hour pipeline, gas and terminal operation control services for Enbridge US must provide on line access to a current database containing qualification data for their operators.

Third-Party Vendor Qualification

- Third-party vendor qualification options may be considered upon presentation of valid programs.

- Enbridge US recognizes two third party operator qualification vendors.
  - National Center for Construction, Education and Research (NCCER)
    - Enbridge US accepts any one of the following NCCER qualifications.
      - Performance Verification
      - Training Module with Performance Verification & Written Test
      - Written Assessment Test including AOC Assessment
    - Enbridge US has requested that contractors certify their own evaluators/instructors through an NCCER Accredited Sponsor to enable them to conduct Performance Verifications and deliver Training Modules to their own employees.

- Enbridge Technology
    - Contractors using Enbridge Technology Operator Qualification material must complete and provide documentation including all of the following parts of each specific Covered Task Training Module.
        - Skill Checklist
        - AOC Scenario
        - Final Exam
    - Evaluators, with proper expertise, may be selected by the Contractor to deliver the Training Module and testing.

Contractor Documentation of Approved Qualification

- Contractor documentation must be submitted for approval prior to the start of covered work that demonstrates qualification of their employees under Subpart G in 49 CFR Part 195 or Subpart N in 49 CFR Part 192. This will include an adequate description of:

    - Any of the following evaluation methods for **Covered Tasks** and **Abnormal Operating Conditions** including:
        - Observation of task performance/simulation
        - Verbal review of task procedure by the individual
        - Written test

    - The following identifying data:
        - The name(s) of qualified individual(s)
        - Each covered task specific to the work being performed
        - Dates of satisfactory completion of Task and Abnormal Operating Condition evaluation(s)

- Enbridge US will use ISNetworld Internet Compliance Records Management as the contractor documentation source to identify qualified workers prior to the beginning of work and for the duration of any work that includes covered tasks.
    - Contractors, subscribing to ISNetworld, who propose to provide services to Enbridge US, must grant access to their qualification data by submitting an OQ Report on ISNetworld updated as personnel changes throughout the job.

- Prior to contractor qualification data appearing on ISNetworld, contractors will be required to show documentation of qualification prior to the commencement of work by submitting to Enbridge US by any one of the following:
    - NCCER completed Performance Verification Form
    - NCCER Official Transcript
    - NCCER completed Training Report Form (Form 200)
    - Enbridge Technology covered task module Skill Checklist, AOC Scenario and Final Exam

- Contractor qualification records will be retained within the ISNetworld system and/or by Enbridge US for five years.

Work Site Documentation Requirements

- Contractors must provide the names and the qualification status of all individuals they intend to assign to Enbridge jobs that include covered tasks at least 24 hours prior to the start of work. The Covered Task Worker ID form is used for this purpose (see Appendix H)
- Enbridge personnel will verify the qualifications of the proposed workers via proper documentation and send a list of names to the Enbridge representative at the job site.
- Qualified worker picture ID's may be checked prior to the start of work at the job site to confirm the identity of qualified individuals as needed.
- A representative of Enbridge and a contractor representative will complete the Contractor Operator Qualification Report (Appendix I) listing the name and qualification status of each worker.
- Completed Contractor Operator Qualification Reports are kept in the Project File.

CHANGE MANAGEMENT

- Changes to the plan and/or the Operator Qualification process are received and implemented as outlined in the Change Feedback Mechanism in Appendix E and in the Change Management Methodology in Appendix F

- Change feedback may be received via:
  - Regulators
  - Management
  - Administrator
  - Industry/COOQ
  - Evaluators
  - Contractors
  - Employees/Supervisors

- Changes, which affect covered tasks, will be assessed by the plan administrator to determine if re-qualification is necessary. If re-qualification is required all affected individuals will be notified and re-qualified by their supervisors.

- Changes, which are OQ Plan or regulation related, will be reviewed by the OQ Steering Committee. The recommended change will be assessed and action will be determined. If re-qualification is required all affected individuals will be notified through their supervisors.

- Changes will be evaluated by the administrator to determine if adjustments to procedures are required.

- All changes to the plan and/or the operator Qualification process as well as the method of communication are documented on the OQ Change Management form in Appendix G.

- Supervisors/Evaluators are expected to implement the changes affecting them in their areas.

- If there is change to the task procedure requiring a new understanding of how the task is performed, individuals shall be re-evaluated as if it were a new task.

RECORDKEEPING FOR ENBRIDGE US EMPLOYEES

- Qualification records will be maintained that include identification of the following:
  1) Name of qualified individual
  2) Covered tasks that the individual is qualified to perform
  3) Dates of qualification
  4) Qualification method
     - Description of evaluation
     - Description of Abnormal Operating Condition discussion

- Each evaluator will enter evaluation documentation into the Covered Task Evaluation Forms in the DOT Operator Qualification computer database within Lotus Notes.

- Management will periodically monitor the evaluators' entries in the DOT Operator Qualification Database to track progress and ensure proper compliance.

- The completed Operator Qualification Evaluation Form specific to each job class will be printed. The signature page will be printed and signed by employee, evaluator and manager in recognition of satisfactory evaluation of identified covered tasks and attached to the back of the OQ Evaluation Form.

- All records of qualification of current and former employees will be retained in hard copy as well as computer documentation in their respective region office for five years.

- OQ Change Management forms will be retained by the OQ administrator for a minimum of five years.

MONITORING PROGRAM PERFORMANCE

- Plan performance will be monitored yearly through audits conducted by the OQ Steering Committee.

APPENDIX

A. Covered Task Chart

B. Definitions

C. Abnormal Operating Condition Examples
- Industry General
- Pipeline Maintenance
- Patrol Pilot
- Electrical
- Mechanical
- Terminal/Delivery
- Cathodic Protection Inspection
- Gas Technical
- ND Gauger/Utility/Operator

D. Post Incident Process

E. Change Feedback Mechanism

F. Change Management Methodology

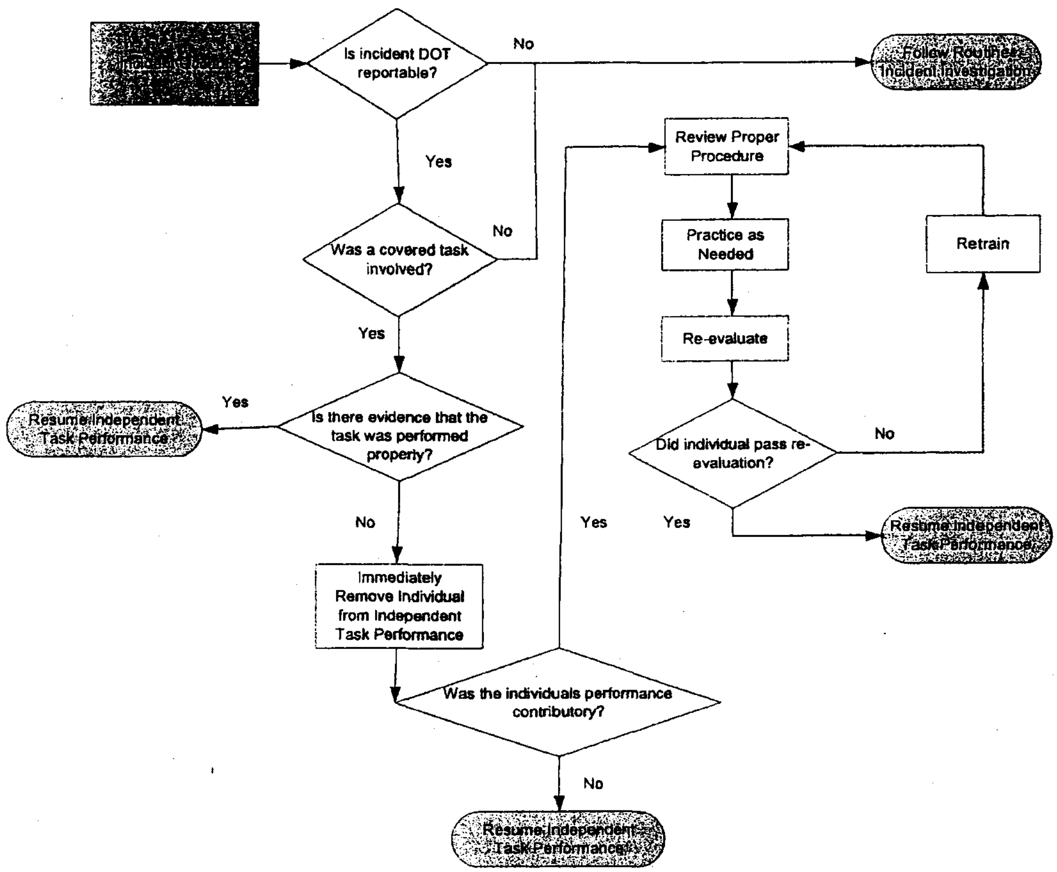
G. OQ Change Management form

H. Covered Task Worker ID Form

I. Contractor Operator Qualification Report

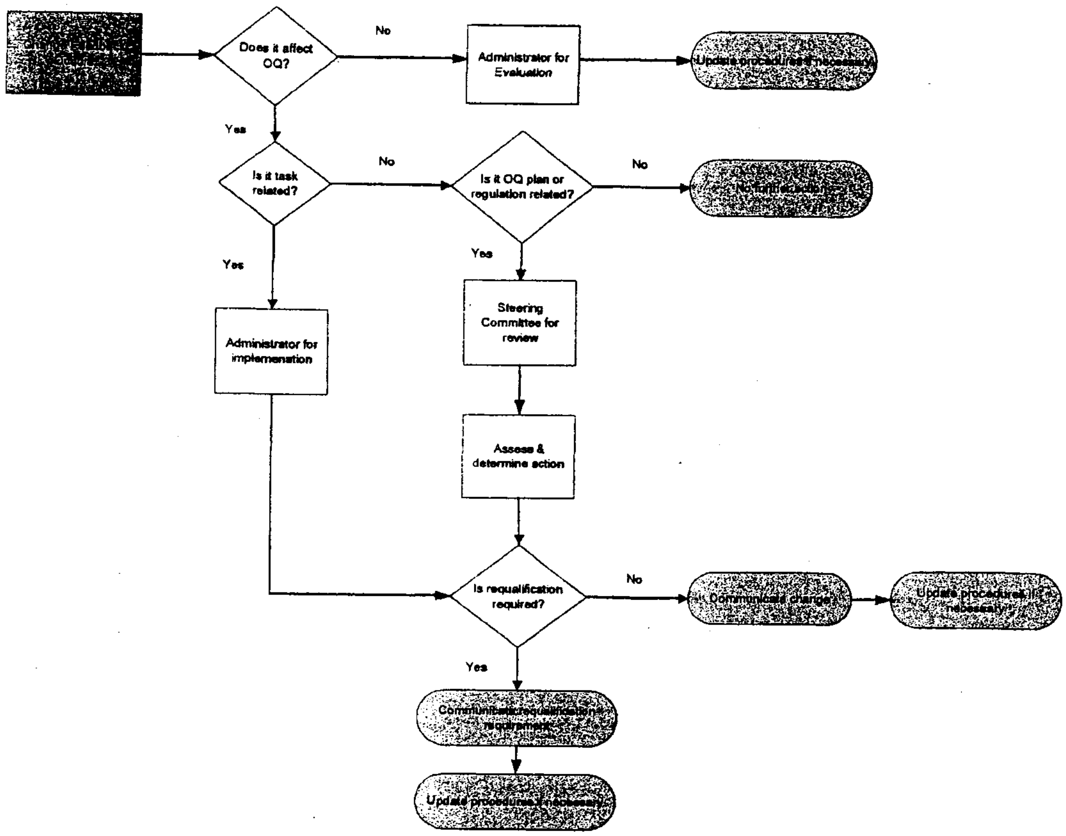
Appendix D

POST INCIDENT PROCESS



Appendix F

CHANGE MANAGEMENT METHODOLOGY



ENBRIDGE

DOT Operator Qualification Plan
Change Management Form

Date _____

Form Number OQCM - ______

Change Feedback (check all that apply)

☐ **Regulatory Change**	☐ **Post Incident Review**
☐ **New Technology**	☐ **Policy/Procedure Change**
☐ **Employee/Contractor Feedback**	☐ **Other** (Specify)

Details of Change

Revisions Required (check all that apply)

	Element Affected	Description of Change Required	Priority Level
☐	**No Action Required**		
☐	**OQ Written Plan**		
☐	**Covered Task Lists**		
☐	**PBT Job Outlines**		
☐	**DOT OQ Database**		
☐	**ISNetworld**		
☐	**NCCER**		
☐	**Other** (Specify)		

Priority Level: I (initiate within 30 days)
II (initiate within 31-60 days)
III (initiate within 61-90 days)
IV (initiate within 3 – 9 months)

Change Approval (check all that apply)

☐ **OQ Steering Committee**	☐ **OQ Administrator**
☐ **Other** (specify)_____	

Affect on Individual Qualification (check only one)

- ☐ **Not Applicable**
- ☐ **No Affect on Existing Qualifications**
- ☐ **Minor Affect – Individual may retain qualification until next reevaluation.**
- ☐ **Significant Affect – Individual(s) must re-qualify prior to performing affected covered task(s).**

Communication of Change (check all that apply)

Notification	Means	Date Completed
☐**Not Required**		(Click space to add date)
☐**Steering Committee**	☐**E-mail** ☐**Verbal**	
☐**Supervisors**	☐**E-mail** ☐**Verbal**	
☐**Employees**	☐**E-mail** ☐**Verbal**	
☐**Contractors**	☐**E-mail** ☐**Verbal**	
☐**OQ Compliance Group**	☐**E-mail** ☐**Verbal**	
☐**Management**	☐**E-mail** ☐**Verbal**	
☐**Other** (Specify)_____	☐**E-mail** ☐**Verbal**	

Completion of Change Management Process

Name ____________________ **Title** ____________________

Date ____________________

Comments

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ENBRIDGE™

April 14, 2005

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2004-5029M

Dear Mr. Huntoon:

This submittal is in response to your "Notice of Amendment" sent to this office dated September 20, 2004. Enbridge has worked with Office of Pipeline Safety personnel to implement changes to our Operator Qualification (OQ) plan. Your office has requested a formal submittal of the Small Piping Repair/Replacement task and associated Abnormal Operating Conditions (AOCs), which are attached for your review.

Should you have any further questions or concerns, please feel free to contact me at (715) 394-1534.

Sincerely,

Mark Willoughby

Attachments
c: Leisa Doberstein
Boyd Haugrose
Steve Irving
Gregory Ochs

Small Piping Repair/Replacement

Objective
Ensure proper application of small piping

Normal Procedure

1. Contact Control Center, if impacted
2. Isolate area to be repaired/replaced
3. Ensure use of proper valves, fittings, tubing and nipples by checking pressure rating and fluid applicability
4. Ensure adequate wall thickness of piping for the design pressure
5. Bend tubing with proper sized tubing bender to avoid damage
6. Seal threaded fittings using Teflon Tape or other appropriate thread sealant
7. Tighten all fittings to manufacturers or ANSI specifications
8. De-isolate and check piping for leakage after completion
9. Check piping installations for excessive vibration
10. Notify Control Center of return to service, if required

Notes

Cross Reference

Enbridge Engineering Standards (D 06-102 Sect 4)
Manufacturers Specifications
ANSI

Additional AOC's to OQ Database

AOC:

- During routine maintenance you notice a fitting is leaking product.

AOC Recognition:

- How would you recognize it?
  - Product has collected below the fitting.
  - The fitting has product dripping from the bottom.
  - Audible hissing from around fitting or tubing.
  - Frost buildup on or around vicinity of fitting.
  - Leak detected by use of detection agent such as snoop.

AOC Response:

- What would you do?
  - Notify Control Center.
  - Follow Normal Procedure repairs.
  - Report as required (O&MP 02-02-01).

AOC:

- The fittings bind when disconnecting small piping (after depressurization and draining).

AOC Recognition:

- How would you recognize it?
  - The fittings may spring apart or move off to the side.

AOC Response:

- What would you do?
  - Re-pipe, correcting the misalignment of fitting, ensuring the piping is installed stress free.

AOC:

- A nut has been over tightened.

AOC Recognition:

- How would you recognize it?
  - The gap between the nut and the fitting body is too narrow.
  - There may be damage to the fitting or a split in the tubing.

AOC Response:

- What would you do?
  - Inspect the fitting and replace tubing and ferrule.

AOC:

- As you are applying pressure to a newly installed nut and ferrule type of connection the tubing pulls out of the connection.

AOC Recognition:

- How would you recognize it?
  - The tubing kicks back.

AOC Response:

- What would you do?
  - Immediately stop pressurization and take steps to reduce pressure to atmospheric level.
  - Disassemble connection and determine integrity. Replace if necessary.
  - If product leakage occurs, report as required (O&MP 02-02-01).

AOC:

- After pressurizing a newly installed connection (any type), you observe the connection is leaking.

AOC Recognition:

- How would you recognize it?
  - Product is dripping or spraying out of the connection.

AOC Response:

- What would you do?
  - Immediately depressurize the line the connection is part of and disassemble and inspect the connection.
  - Replace or reconnect as appropriate, insuring proper installation and tightness.
  - NEVER tighten a fitting or connection that is under pressure.

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ENBRIDGE™

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FAX: 816-329-3831

July 27, 2005

RECEIVED JUL 28 2005

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2004-5029M

Dear Mr. Huntoon:

This submittal is in response to your "Notice of Amendment" sent to this office dated September 20, 2004. Enbridge has worked with Office of Pipeline Safety personnel to implement changes to our Operator Qualification (OQ) Plan. Your office has requested a formal submittal of the changes to the plan associated with the Notice of Amendment. The changes include the following:

Item 2 – Post Incident Process - Flawed Procedure

Appendix D (attached) has been amended to reflect the change. The following wording has been added to the plan under the "Required Re-evaluation after Qualification" section:

> "If the task was performed properly yet there is evidence that the procedure is flawed the procedure will be re-written by the administrator. Direction to re-qualify all affected individuals may follow if the procedure re-write necessitates this."

Item 3 - Change Management - Immediate Communication

This following wording has been added to the plan under the "Change Management" section:

> "Feedback received which is critical in nature and requires immediate action will be communicated, via email or verbally, by the administrator or designate to all affected internal and external parties directly following notification."

As well, the DOT Operator Qualification Plan Change Management Form (attached) has been amended to include the requirement for urgent notification and revision implementation.

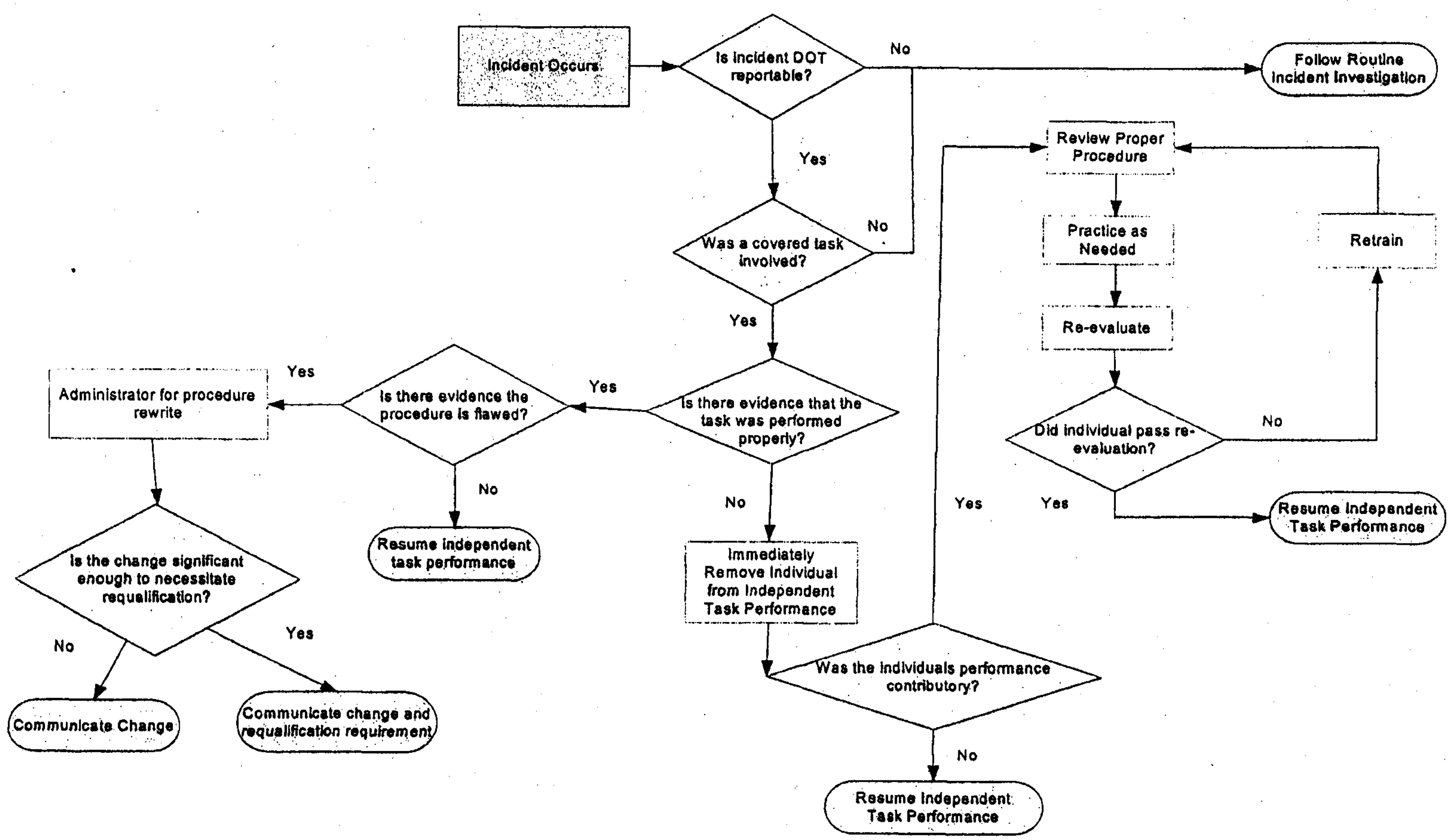
Should you have any further questions or concerns, please feel free to contact me at (715) 394-1534.

Sincerely,

Mark Willoughby

Attachments
c: Leisa Doberstein
Boyd Haugrose
Steve Irving
Gregory Ochs

POST INCIDENT PROCESS



ENBRIDGE

DOT Operator Qualification Plan
Change Management Form

Date

Form Number

Change Feedback (check all that apply)

☐ **Regulatory Change**	☐ **Post Incident Review**
☐ **New Technology**	☐ **Policy/Procedure Change**
☐ **Employee/Contractor Feedback**	☐ **Other** (Specify)

Details of Change

Revisions Required (check all that apply)

	Element Affected	Description of Change Required	Priority Level
☐	**No Action Required**		
☐	**OQ Written Plan**		
☐	**Covered Task Lists**		
☐	**PBT Job Outlines**		
☐	**DOT OQ Database**		
☐	**ISNetworld**		
☐	**NCCER**		
☐	**Other** (Specify)		

Priority Level:

1. Complete immediately following notification
2. Complete within 30 days
3. Complete within 31-60 days
4. Complete within 61-90 days
5. Complete within 3 – 9 months

Change Approval (check all that apply)

☐ **OQ Steering Committee**	☐ **OQ Administrator**
☐ **Other** (specify)_____	

Affect on Individual Qualification (check only one)

☐ **Not Applicable**

☐ **No Affect on Existing Qualifications**

☐ **Minor Affect – Individual may retain qualification until next reevaluation.**

☐ **Significant Affect – Individual(s) must re-qualify prior to performing affected covered task(s).**

Communication of Change (check all that apply)

Notification	Means	Priority Level	Date Completed
☐**Not Required**			
☐**Steering Committee**	☐**E-mail** ☐**Verbal**		
☐**Supervisors**	☐**E-mail** ☐**Verbal**		
☐**Employees**	☐**E-mail** ☐**Verbal**		
☐**Contractors**	☐**E-mail** ☐**Verbal**		
☐**OQ Compliance Group**	☐**E-mail** ☐**Verbal**		
☐**Management**	☐**E-mail** ☐**Verbal**		
☐**Other** (Specify)_____	☐**E-mail** ☐**Verbal**		

Priority Level:

1. Complete immediately following notification
2. Complete within 30 days
3. Complete within 31-60 days
4. Complete within 61-90 days
5. Complete within 3 – 9 months

Completion of Change Management Process

Leisa Doberstein
Name

Signature

Compliance Qualifications Coordinator
Title

Date

Comments

U.S. Department
of Transportation

Pipeline and
Hazardous Materials
Safety Administration

Central Region
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

August 25, 2005

Mr. Mark Willoughby
Manager, US Compliance and Risk Management
Enbridge Energy Company, Inc.
119 N. 25th Street
Superior, WI 54880-5427

CPF No. 3-2004-5029M

Dear Mr. Willoughby:

As a result of an operator qualification inspection conducted by representatives of the Office of Pipeline Safety (OPS) on July 28-29, 2004, a Notice of Amendment was issued to you on September 20, 2004, requiring amendment to your operator qualification program to comply with 49 CFR §195.505.

We have received the amended program you submitted by letters dated October 19, 2004, April 15, 2005 and July 27, 2005. The amended program submitted has been reviewed and is acceptable.

This letter is to inform you that no further action is necessary concerning the Notice of Amendment and that this case is being closed. Thank you for your cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region,
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE of PROBABLE VIOLATION
WARNING LETTER
NOTICE of AMENDMENT
and
LETTER of CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

December 21, 2004

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
1100 Louisiana
Suite 2950
Houston, TX 77002-7002

CPF No. 3-2004-5038

Dear Mr. Tutcher:

During the weeks of May 12, 2003, and June 2, 2003, representatives of the Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an inspection of Enbridge Pipelines, LLC's (Enbridge) HCA Management Plan at its facility in Superior, Wisconsin.

As a result of the inspection, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195.

1. **§195.452 Pipeline integrity management in high consequence areas.**

(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:
(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1..............................	December 31, 2001.
Category 2..............................	November 18, 2002.
Category 3..............................	Date the pipeline begins operation.

At the time of inspection, Enbridge had constructed and placed into service 36" diameter pipe in parallel with existing Enbridge pipelines as part of the Terrace III project. These newly constructed 36" pipeline segments are Category 3 pipe per §195.452 (a)(3), since they were constructed after May 29, 2001. For this new 36" pipe, Enbridge failed to identify pipeline segments which could affect high consequence areas (HCA) prior to the start of pipeline operation. The existing pipelines had HCAs identified, and subsequent to the OPS inspection Enbridge completed segment identification for the new 36" pipe placed in service as part of the Terrace III project.

2. **§195.452 Pipeline integrity management in high consequence areas.**

(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:
(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(c) What must be in the baseline assessment plan?
(1) An operator must include each of the following elements in its written baseline assessment plan:
(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

Enbridge's HCA Management Plan prioritized pipelines for completion of a crack susceptibility study. Based on various factors, including failure history, longitudinal seam type, previous inspection results, etc., susceptibility was established and assessment methods included in the baseline assessment plan (BAP) for higher priority pipelines. However, for lower priority pipelines the crack susceptibility study was not completed and assessment methods relating to crack-like anomalies (e.g. railroad fatigue cracks, flash weld seam anomalies, stress corrosion cracking, etc.) was not established. Although the likelihood of failure due to cracking for lower priority pipeline segments may be less than the higher priority pipeline segments, the determination of all necessary assessment methods should have been completed and included in the BAP for all pipeline segments by March 31, 2002 per §195.452(b)(1) for Category 1 pipelines.

3. §195.452 **Pipeline integrity management in high consequence areas.**

(h) What actions must an operator take to address integrity issues?
(2) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

For the Line 4 - Plummer to Clearbrook pipeline section discovery was not made within 180 days of the assessment for certain anomalies. The in-line inspection was completed on May 30, 2002, and the final tool vendor report was received on November 1, 2002. Several anomalies that were identified in the vendor's report were excluded from the remediation plan on the basis that these anomalies had been previously repaired. Upon further review Enbridge determined that these anomalies had actually not been previously remediated and the date of discovery was revised to be May 2003. These anomalies were categorized as 180 day repairs per §195.452(h)(4)(iii) and were scheduled for remediation.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violations persists up to a maximum of $1,000,000 for any related series of violations.

In regard to Items 1, 2, and 3, we have reviewed the circumstances and supporting documents involved in this case, and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations, we will take enforcement action when and if the continued violations come to our attention.

Additionally, the inspection found that Enbridge had developed and implemented an integrity management program for pipeline segments that could affect high consequence areas (HCA) pursuant to §195.452. However, it appears that Enbridge's written integrity management program must be amended to address the following items required by §195.452.

4. **§195.452 Pipeline integrity management in high consequence areas.**

(f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(1) A process for identifying which pipeline segments could affect a high consequence area;

The segment identification process is manually performed by an analyst using USGS maps. As such, the process should be sufficiently detailed and documented to direct the analyst to properly perform segment identification with consistent results. Specifically, the water transport of spilled oil was considered to end where a control point (location where spill containment measures are deployed) exists with a minimum of 3 hours flow time. The control points were determined by the analyst, but were not present on the documented maps. In the case of overland flow, the distance traveled was dependent on the slope of the terrain, but a composite buffer zone showing the ultimate distance reached was not presented graphically on the HCA identification maps.

5. **§195.452 Pipeline integrity management in high consequence areas.**

f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(c) What must be in the baseline assessment plan?
(1) An operator must include each of the following elements in its written baseline assessment plan:
(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?
(1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:
(vi) Existing or projected activities in the area;

The process of prioritization of pipeline assessments in the Baseline Assessment Plan did not include explicit documentation on how existing or projected activities are considered when developing the assessment schedule.

6. **§195.452 Pipeline integrity management in high consequence areas.**

f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(d) When must operators complete baseline assessments? Operators must complete baseline assessments as follows:
(3) Newly-identified areas.
(i) When information is available from the information analysis (see

paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

Enbridge's HCA Management Plan did not include the requirements for incorporating newly identified segments affecting high consequence areas into its baseline assessment plan within one year of identification, and performing a baseline assessment within 5 years of identification.

7. **§195.452 Pipeline integrity management in high consequence areas.**

f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(h) What actions must an operator take to address integrity issues?
(4) Special requirements for scheduling remediation.
(i) Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see Sec. 195.3).

Enbridge's HCA Management Plan references the use of RSTRENG to calculate the temporary reduction in operating pressure for immediate repair conditions, rather than section 451.7 of ASME B31.4. The time frame to complete an engineering evaluation to determine the pressure reduction for other immediate repair conditions (e.g. topside dents with indication of metal loss, cracks, or stress riser, and topside dents greater than 6% deep) was not specified. Actions to be taken, such as pressure reduction or shutdown of the affected segment, while an engineering evaluation is completed was not defined in the HCA Management Plan.

8. §195.452 **Pipeline integrity management in high consequence areas.**

f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(g) What is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:
(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys;

Enbridge's information analysis procedures did not adequately consider data gathered from other inspections and tests, including cathodic protection surveys. Additionally, the HCA Management Plan did not include a process to communicate assessment and repair results to corrosion control personnel for consideration of additional actions to further mitigate internal and external corrosion. Also, the process of evaluation of each pipeline segment by analyzing all available data was insufficient to gain a complete understanding of pipeline integrity.

In regard to Items 4 through 8, when it is found that an operator's plans and/or procedures are inadequate, the operator, after notice and opportunity for hearing as provided in 49 C.F.R. §190.237, may be required to amend its plans and procedures. This letter serves as your notification of inadequate plans and procedures as well as your response options as prescribed under §190.237. The operator is allowed thirty (30) days after receipt of such notice to submit written comments or request an informal hearing. After considering the material presented, OPS is required to notify the operator of the required amendment or withdraw the notice proposing the amendment. If you do not desire to contest the notice, within thirty (30) days of receipt of this notice you must prepare the revised procedures and provide a copy to:

Director, Central Region
Office of Pipeline Safety
901 Locust St, Room 462
Kansas City, MO 64106

In addition to the items noted above, the inspection revealed areas of concern that we would like to bring to your attention.

- Enbridge utilized regression analysis to predict overland spread versus release volume for various topographical slopes. Not all release data, including the spill at Cohasset, MN, was used to verify that volume release and overland spreads predicted by the segment identification process were appropriate. Additionally, the time for containment of the spilled product was assumed to be 3 hours. Validation of this assumption through comparison of actual response times during spills should be conducted.

- Discrepancies were noted between the segments identified as "could affect" on the HCA maps and Table 2 of the HCA Management Plan.

- Enbridge did not account for multiple instances (overlap) of common types of HCAs when segment identification results were input into the consequence (risk) analysis. For example, when multiple drinking water HCAs are affected, this may be of greater consequence than if one drinking water HCA is affected in the event of a spill.

- The inspection team noted instances where the data entered into the risk model was not updated and/or entered prior to using risk results for prioritization of the assessment schedule. Additionally, it appeared to the inspection team that the "impact on business" was a significant factor of the risk ranking of some segments, and that this factor may need to be re-visited to determine if the weighting is appropriate.

- Flanges and fittings were the primary sources of leaks at facilities; however, this was not well-considered in the evaluation of risks at facilities.

- There were instances of discovery not being made within 180 days of assessment due to delayed reporting by the in-line inspection vendor.

We appreciate your attention to these matters.

Please refer to CPF 3-2004-5038 in all correspondence related to this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
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Mark J. Willoughby, Manager
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mark.willoughby@enbridge.com

ENBRIDGE™

January 28, 2005

VIA NEXT DAY MAIL
FAXED: 816 329-3831

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

Re: CPF No. 3-2004-5038

Dear Mr. Huntoon:

In response to the Notice of Probable Violation, Warning Letter, Notice of Amendment and Letter of Concern dated December 21, 2004, we offer the following comments:

Item 1

At the time of inspection, Enbridge had constructed and placed into service 36" diameter pipe in parallel with existing Enbridge pipelines as part of the Terrace III project. These newly constructed 36" pipeline segments are Category 3 pipe per §195.452 (a) (3), since they were constructed after May 29, 2001. For this new 36" pipe, Enbridge failed to identify pipeline segments which could affect high consequence areas (HCA) prior to the start of pipeline operation. The existing pipelines had HCAs identified, and subsequent to the OPS inspection Enbridge completed segment identification for the new 36" pipe placed in service as part of the Terrace III project.

Response:
We currently capture new engineering designs, as well as changes to configuration or parameters through an existing Engineering Department process. Compliance and Risk personnel are now involved from the inception of Project Execution Plans. Involvement with representatives from key areas of the company at the initial planning stages of projects will help to ensure that HCA identification and analyses can be scheduled for completion prior to project completion. This change was discussed during and implemented following our annual review meeting of the HCA Management Plan in September, 2004. Section 2.1.1 of Engineering's Project Execution Plan identifies the requirement of Compliance and Risk personnel involvement. The HCA Management Plan also included this process as a specific part of the annual review, and it has been incorporated into Tab 3, Table 3.

Item 2

Enbridge's HCA Management Plan prioritized pipelines for completion of a crack susceptibility study. Based on various factors, including failure history, longitudinal seam type, previous inspection results, etc., susceptibility was established and assessment methods included in the baseline assessment plan

(BAP) for higher priority pipelines. However, for lower priority pipelines the crack susceptibility study was not completed and assessment methods relating to crack-like anomalies (e.g. railroad fatigue cracks, flash weld seam anomalies, stress corrosion cracking, etc.) was not established. Although the likelihood of failure due to cracking for lower priority pipeline segments may be less than the higher priority segments, the determination of all necessary assessments methods should have been completed and included in the BAP for all pipeline segments by March 31, 2002 per §195.452(b)(1) for Category 1 pipelines.

Response:
At the time of the audit (May 2003), Enbridge had completed a susceptibility analysis of all pipelines and the resulting relative risk ranking was included within the Enbridge HCA Management Plan. In addition, a system-wide quantitative crack analysis using the Paris Law / Fatigue equation had been initiated and was outlined in the following section of the Enbridge HCA Management Plan:

> *"...a qualitative relative ranking of pipeline segments is being used as an interim measure to help identify segments where additional assessment for cracking is required. For this analysis, causal factors are reviewed by technical professionals within the Pipeline Integrity department to establish interim likelihood of failure due to cracking. As crack susceptibility model results become more widely available, current qualitative analysis will be supplemented by quantitative modeling data. Based on the susceptibility analysis conducted thus far, there are no pipeline segments requiring near term baseline assessment evaluations beyond those which have already been assessed."*

At the time of the audit, Enbridge committed to completing the quantitative crack analysis by year end 2004. This quantitative crack analysis was completed. The updated Baseline Assessment Plan will reflect quantitative crack analysis results.

Currently, Enbridge is using the high-resolution crack detection in-line inspection as the assessment method for pipeline segments susceptible to crack-like anomalies.

<u>Item 3</u>

For the Line 4 – Plummer to Clearbrook pipeline section discovery was not made within 180 days of the assessment for certain anomalies. The in-line inspection was completed on May 30, 2002, and the final tool vendor report was received on November 1, 2002. Several anomalies that were identified in the vendor's report were excluded from the remediation plan on the basis that these anomalies had been previously repaired. Upon further review Enbridge determined that these anomalies had actually not been previously remediated and the date of discovery was revised to be May 2003. These anomalies were categorized as 180 day repairs per §195.452(h) (4) (iii) and were scheduled for remediation.

Response:
In 2002, during the creation of the remediation plan for the Line 4 Plummer to Clearbrook pipeline section, it was determined that a complete review of all historical excavation and repair records should be conducted. This process took longer than normal and should not be considered reflective of standard processes.

Since 2002, Enbridge has further improved its systems relative to the 180 day timeframe as follows:

- Enbridge has negotiated reduced durations for in-line inspection report delivery from the in-line inspection vendor.
- Enbridge has implemented improved in-line inspection report tracking tools to enhance on-time delivery.
- In 2003 Enbridge initiated a project to create a computer database that is designed to capture certain historical excavation and repair records in one electronic location. This will expedite a number of quality assurance checks prior to initiating mitigation programs.

Item 4

The segment identification process is manually performed by an analyst using USGS maps. As such, the process should be sufficiently detailed and documented to direct the analyst to properly perform segment identification with consistent results. Specifically, the water transport of spilled oil was considered to end where a control point (location where spill containment measures are deployed) exists with a minimum of 3 hours flow time. The control points were determined by the analyst, but were not present on the documented maps. In the case of overland flow, the distance traveled was dependent on the slope of the terrain, but a composite buffer zone showing the ultimate distance reached was not presented graphically on the HCA identification maps.

Response:
Subsequent to the June 2003 audit, overland flow buffers representing a composite of the slopes in the area of interest are created by the subject matter expert and are shown on the working maps used to identify "could affect" HCA segments. This process is also aided via electronic digital elevation mapping techniques and the use of Spatial Analysis (a Geographic Information Systems program). The transport of oil on water via advection was considered over distance representing the closest control point downstream of a three-hour travel time. The control points will be shown or referenced on new HCA maps.

Item 5

The process of prioritization of pipeline assessments in the Baseline Assessment Plan did not include explicit documentation on how existing or projected activities are considered when developing the assessment schedule.

Response:
As detailed in the Enbridge HCA Management Plan, Enbridge has a well developed and comprehensive third party damage prevention program that includes public awareness programs, signage, right of way clearing, aerial patrols, third party encroachment research, support of one-call systems, installation of tape or concrete above the lines in some areas, increased landowner visitation and planning of community pipeline information sessions. Enbridge continues to improve these prevention programs. For example, in 2004 Enbridge implemented the new public awareness requirements as per API 1162.

As a result of the above mentioned actions, incidents of damage to the Enbridge pipeline system due to 3rd party activities are substantially lower than industry norms. Consequently, Enbridge views the current programs to appropriately manage existing or projected 3rd party activities. Further, Enbridge reviews the programs on an ongoing basis for appropriateness and makes changes where necessary. For example, Enbridge will conduct a study along each pipeline to determine if 3rd party activity has increased.

Our current program of running mechanical damage tools with corrosion and crack tools as shown in our Baseline Assessment Plan has adequately managed mechanical damage including 3rd party activities. If, through continual analysis, it is determined that the frequency of in-line inspection needs to be increased the Baseline Assessment Plan will be revised.

Item 6

Enbridge's HCA Management Plan did not include the requirements for incorporating newly identified segments affecting high consequence areas into its baseline assessment plan within one year of identification, and performing a baseline assessment within five years of identification.

Response:
Enbridge's HCA Management Plan was revised to address this issue. The following excerpt was taken from Tab 5 of our HCA Management Plan, Baseline Assessment--Main Line: "Prior to the annual running of the risk assessment model, high consequence areas will be reviewed for changes or additions of new unusually sensitive areas. As such, any change or new unusually sensitive areas will be incorporated into the Baseline Assessment Plan within one year from the date the area is identified. On an annual basis, the Baseline Assessment Plan will be updated in consideration of new risk assessment data and the plan will be revalidated to ensure all High Consequence Areas are assessed in accordance with regulatory requirements. Specifically, the baseline assessment of any line pipe that could affect the newly identified high consequence area will be complete within five years from the date the area is identified."

Item 7

Enbridge's HCA Management Plan references the use of RSTRENG to calculate the temporary reduction in operating pressure for immediate repair conditions, rather than section 451.7 of ASME B31.4. The time frame to complete an engineering evaluation to determine the pressure reduction for other immediate repair conditions (e.g. topside dents with indication of metal loss, cracks, or stress riser, and topside dents greater than 6% deep) was not specified. Actions to be taken, such as pressure reduction or shutdown of the affected segment, while an engineering evaluation is completed was not defined in the HCA Management Plan.

Response:
As documented in the HCA Management Plan, the Excavation Program Guideline Document includes detailed defect mitigation procedures. This Guideline has been revised to include the following text:

> Corrosion Related Pressure Restriction:
> For any corrosion feature that meets the immediate repair condition as defined in O&M Procedure 06-02-02 (Defect Evaluation and Repair Methods) a pressure restriction in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 will be implemented within 48 hours of completion of the Final Dig List (date of discovery).

Geometry Related Pressure Restriction
For any geometry feature that meets the immediate repair condition as defined in O&M Procedure 06-02-02 (Defect Evaluation and Repair Methods) a pressure restriction shall be implemented within 48 hours of discovery. The pressure restriction shall limit the maximum pressure at the dent location to 80% of the highest pressure experienced at that location within the past three months.

Crack Related Pressure Restriction
For any crack feature that meets the immediate repair condition as defined in O&M Procedure 06-02-02 (Defect Evaluation and Repair Methods) a pressure restriction will be taken based on a remaining strength calculation in order to maintain a safety factor of 1.25 (U.S. and Canada) within 48 hours of completion of the Final Dig List.

Item 8

Enbridge's information analysis procedures did not adequately consider data gathered from other inspections and tests, including cathodic protection surveys. Additionally, the HCA Management Plan did not include a process to communicate assessment and repair results to corrosion control personnel for consideration of additional actions to further mitigate internal and external corrosion. Also, the process of evaluation of each pipeline segment by analyzing all available data was insufficient to gain a complete understanding of pipeline integrity.

Response:
Enbridge utilizes all available integrity management tools for inspecting and testing the pipeline system including in-line inspection, cathodic protection, above ground surveys, direct assessments and hydrotest.

Enbridge's integrity management plans for each hazard are created by reviewing and analyzing the results from the tests and inspections that are applicable to each hazard. For example, where cathodic protection information is relevant to analysis of corrosion, the data is considered. Generally, however, the cathodic protection data is not relevant to corrosion base line planning since Enbridge utilizes more detailed and accurate information from repeat in-line inspections from which corrosion growth rate analysis can be completed.

The role of each Enbridge Corrosion Control Technician is to implement the cathodic protection program, which includes maintaining the mechanics of the system and ensuring the Enbridge cathodic protection standards are being met. If a change occurs, the Technicians inform the Pipeline Integrity department. The Technicians also provide reports when required by Pipeline Integrity for any analysis or trending work. The Technicians have access to all Pipeline Integrity plans for their areas and are invited to annual integrity management planning sessions. Corrosion mitigation planning is the responsibility of the Pipeline Integrity department and not the Corrosion Control Technicians.

For all hazards (external corrosion, internal corrosion, SCC, weld cracking, mechanical damage) specific defect analysis is conducted. Documented processes for analysis and planning are in place – please refer to Baseline Assessment – Mainline - Appendix B. However, based upon your comments Enbridge will amend our documents to enhance and improve the descriptions.

In addition to the above, we have addressed the following areas of concern, as noted in your letter:

- **Enbridge utilized regression analysis to predict overland spread versus release volume for various topographical slopes. Not all release data, including the spill at Cohasset, MN, was used to verify that volume release and overland spreads predicted by the segment identification process were appropriate. Additionally, the time for containment of the spilled product was assumed to be three hours. Validation of this assumption through comparison of actual response times during spills should be conducted.**

  Response:
  Transport characteristics for spills representative of overland flow will be used to maintain and modify the regression analysis and volume out predictions as appropriate. This work will occur coincident with the annual maintenance of the Plan (Tab 3, Table 3, in HCA Management Plan).

- **Discrepancies were noted between the segments identified as "could affect" on the HCA maps and Table 2 of the HCA Management Plan.**

  Response:
  An omission of a pipe segment near Manistique, Michigan from the map was detected and the oversight corrected. The tables are used to generate the maps, and should match. In the future, the table and maps will be updated coincident with each other in an effort to eliminate the potential for inconsistencies. The last task in Table 3 of the HCA Management Plan was added to assure this is the case.

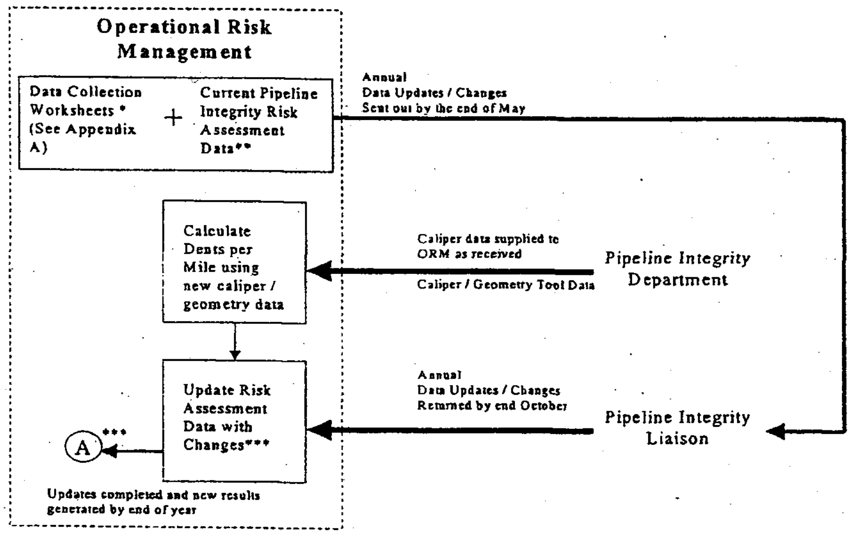
- **Enbridge did not account for multiple instances (overlap) of common types of HCAs when segment identification results were input into the consequence (risk) analysis. For example, when multiple drinking water HCAs are affected, this may be of greater consequence than if one drinking water HCA is affected in the event of a spill.**

  Response:
  The Bass Trigon Integrity Assessment Program (IAP) V5.8 software is unable to address the situation where multiple instances (overlap) of common types of HCAs are impacted. Enbridge has made the vendor aware of this requirement. To address the issue in the interim, Enbridge has developed a process that manually identifies overlap high consequence areas then includes these in the generation of the risk assessment results such that areas with HCA overlaps will have a greater consequence score than those without.

- **The inspection team noted instances where the data entered into the risk model was not updated and/or entered prior to using risk results for prioritization of the assessment scheduled. Additionally, it appeared to the inspection team that the "impact on business" was a significant factor of the risk ranking of some segments, and that this factor may need to be re-visited to determine if the weighting is appropriate.**

Response:
The 2003 audit identified a gap in the flow of updated information from Pipeline Integrity to Operational Risk Management for inclusion in the mainline risk assessment model. An annual data update process has been established and is documented in the document "Ongoing Data Management and Maintenance" (included in the ORM Mainline Risk Assessment Reference Manual). The process as it pertains to updates from Pipeline Integrity is illustrated below:

Ongoing Data Management and Maintenance
Annual Pipeline Integrity Data Update Process



* Worksheets outline data requirements and provide data / attribute definitions
** ORM extracts Pipeline Integrity supplied data from IAP
*** Refer to the Document entitled "Data Validation and Quality Control"

7

<u>Consequence Weightings (with focus on Impact on Business)</u>

Enbridge reviewed the impact on business weightings as a result of the 2003 OPS audit observation and subsequently revised its process for weighting the consequence factors. In this approach, the impact on population, environment, and business scores are adjusted so that the mean of all U.S. mainline consequence factor scores equate to the Enbridge consequence weighting philosophy (50% for population, 30% for environment, 20% for business). This approach is documented in the "Consequence Factor Weighting Determination" document located in the ORM Mainline Risk Assessment Reference Manual.

- **Flanges and fittings were the primary sources of leaks at facilities; however, this was not well-considered in the evaluation of risks at facilities.**

  Response:
  Development of a large-scale facility risk model began in 2004. Enbridge anticipates completing model development and validation in late 2005.

  In the absence of a large-scale model, Enbridge continues to utilize small-scale models to assess specific risk factors at our facilities. In 2004 Enbridge developed models to assess flange integrity and site containment risks. These models were used to prioritize work at high-risk sites and to develop multi-year programs to manage risk in these categories. Results from the 2004 programs will be incorporated into the large-scale risk model.

  Enbridge expects to continue to develop and utilize small-scale risk models to address specific integrity needs until the development of a large-scale facility risk model is complete.

- **There were instances of discovery not being made within 180 days of assessment due to delayed reporting by the in-line inspection vendor.**

  Response:
  Please see response provided to Item 3.

We trust that the above information sufficiently addresses all the concerns noted in your December 21, 2004 letter. Enbridge personnel have worked diligently to create a high quality program that effectively captures the intent of CFR 195.452. As we continue to develop this program, we appreciate clarification given by the OPS, and are encouraged that no civil penalties have resulted from this audit. We are confident that the recently enacted procedures and work flow processes discussed above will strengthen our HCA Management Plan.

Should you have any further questions or concerns, please contact me.

Sincerely,

Mark J. Willoughby

c: Steve Irving
Walter Kresic
Dave McNeill
Art Meyer
Dan Tutcher

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 20, 2007

Mr. Terrance McGill
President
Enbridge Pipelines, LLC
1100 Louisiana
Suite 3000
Houston, TX 77002

CPF 3-2004-5038

Dear Mr. McGill:

During the weeks of May 12 and June 2, 2003, representatives from the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of Enbridge Pipelines, LLC's (Enbridge) integrity management procedures in Superior, Wisconsin. As a result of the inspection, Enbridge was issued a Notice of Amendment on December 24, 2004, which proposed amendment of your procedures.

Enbridge submitted its amended procedures on January 26, 2005. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

LETTER OF CONCERN

January 20, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Dan Tutcher
President
Enbridge Energy, Limited Partnership
Suite 3300
1100 Louisiana
Houston, TX 77002-5217

CPF No. 3-2005-5004C

Dear Mr. Tutcher:

On April 26-30, September 13–17, September 20-24 and October 18-22, 2004 a representative of the Central Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of your facilities in Michigan, Ohio, Indiana, Illinois and Wisconsin.

The inspection disclosed the following items of concern. Please give these items your attention.

1. At MP 438.00, Mokena Station, the outer wrap at Unit #1 for both the suction and discharge piping is deteriorated at the pipe to soil interface.

2. At MP 423.02, the pipe to soil reading is -0.802 which does not meet criteria.

3. At MP 383.16, Dundee Station, inside the pump house, there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

4. At MP 193.63, in Vesper Station, the pipe support at the northeast side of the meter run is not in firm contact with the pipe and is not supporting the pipe.

5. At MP 227.52, in Adams Station, on the outside of the pump house at the southeast corner, the pad between the pipe support and pipe was dislodged.

6. Also at Adams Station, inside the pump house, there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

7. At MP 270.77, on Line 14, there is a shorted casing. The pipe to soil reading was -0.974v for both the mainline pipe and the casing.

8. At MP 321.33, in Delavan Station, the pipe support for valve 6-U-1 on the discharge side of the unit is not in firm contact with the pipe and is not supporting the pipe.

9. At MP 340.00, in Walworth Station, inside the pump house, there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

10. Also at Walworth Station, inside the pressure control valve building, the outer wrap on the piping at the pipe to soil interfaces is deteriorated.

11. At MP 552.94, in Vandalia Station, the mainline valve is a motor operated valve; and during the inspection, the valve was placed in local control to test the operation of the valve and although the valve began to close when the "close" button was pushed, the valve continued operating until it was fully closed even after the "stop" button had been pushed. Your personnel have repaired the switch on the valve and after the repair, the valve was successfully tested both under local control and under the control of the Edmonton Control Center.

12. At MP 1561.16 the indicator rod on valve 1561.16-5-V was not working properly.

13. At MP 538.15, Niles Station, MLV 538.15-6-V is a motor operated valve. During the inspection, under local control, the valve did not stop when the stop button was pushed, and the valve went completely closed. Your personnel indicated that the original design for the valve did not plan for the valve to stop once activated under local control. Since the inspection, the operational design of this valve has changed and a new push button switch was installed. The valve was tested under local control and the valve stopped while in travel when the new button was pushed.

These items were discussed with your representatives during the inspection. They indicated that these items would receive attention. The Central Region, Office of Pipeline Safety, has received documents from Enbridge Energy giving evidence that corrective actions for items 1 through 13 inclusive had been completed. The documents have been reviewed by the Office of Pipeline Safety and are acceptable. No additional action is required on items 1 through 13.

The Office of Pipeline Safety appreciates your attention in these matters and good faith efforts to promote continued safety in your organization.

If we can answer any questions or be of any assistance, please contact us at (816) 329-3800. Thank you for your staff's cooperation during this scheduled inspection.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

cc: Mr. Mark J. Willoughby
Manager, U.S. Compliance & Risk Management
Enbridge Energy, Limited Partnership
119 N. 25th Street East
Superior, WI 54880

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED - RETURN RECEIPT REQUESTED

August 18, 2005

Mr. Rich Adams
Vice President, Operations & Technology
Enbridge Transportation Group South
1100 Louisiana, Suite 3300
Houston, Texas 77002

CPF No. 4-2005-2001M

Dear Mr. Adams:

On October 10 and 11, 2004, representatives of the Southwest Region, Office of Pipeline Safety (OPS), and the Texas Railroad Commission, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of the Operator Qualification (OQ) Plan, records and procedures of Shell Gas Gathering, LLC (SGG) at their headquarters office in Houston, Texas. The inspection of SGG's OQ Plan indicated that some modifications were necessary to meet the expectations of OPS as represented by the inspection protocols in place at the time of the inspection. Although many recommendations for plan improvement were made at the time of the inspection, it was recognized the assets owned and/or operated by SGG were being marketed for sale.

On November 17 and 18, 2004, representatives of the Southwest Region, Office of Pipe line Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of the Operator Qualification (OQ) Plan, records and procedures of Enbridge Transportation Group South (ETGS) at their headquarters office in Houston, Texas. During the course of this inspection, it was learned that Enbridge had purchased the SGG assets, which would become a part of the assets operated by ETGS.

Since Enbridge acquired not only the operating assets of SGG but also its management team, this letter is being directed to you. It formalizes the required amendments to SGG's OQ Plan and should be considered when modifying the ETGS OQ Plan to comply with those changes required of your own OQ Plan (transmitted under separate cover). Any combined ETGS/SGG OQ Plan should not contain the errors found in the original OQ Plans of either company.

As a result of the review of the SGG OQ Plan, the requirements for which are located at Title 49, Code of Federal Regulations, Part 192, Subpart N, the following inadequate procedures were noted:

1. **§192.805 Qualification program.**

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a.) Identify covered tasks;

A. The Plan "Overview" section defines "operations and maintenance tasks" (part 2 of the 4 part test) so only those items defined in subparts I, L & M of Part 192 may be considered. The rule's preamble was very clear about O&M tasks being dependent on other subparts of the code for performance criteria. The "Glossary of Terms" contains other definitions which indicate some tasks may have been erroneously excluded from the covered task list. Definitions provided in the regulations must be preserved as written, and not modified by an operator. OPS has posted acceptable definitions at http://primis.rspa.dot.gov/oq/index.htm (in the OQ Home website's Glossary). The problematic definitions contained in the OQ Plan are:

- "Covered Task"
- "Four Part Test"
- "Operations and Maintenance Tasks"
- "Performed on a Pipeline Facility"
- "Tasks Performed on a Pipeline Facility"

B. SGG indicated to the inspection team that Task #27, Atmospheric Corrosion, did not in fact cover "painting" an above-ground pipeline to protect it from atmospheric corrosion, clearly a covered task.

C. There is no "Small pipe, fittings and tubing" task, which ensures individuals recognize these small items on high pressure pipelines can present extreme hazards if one is not competent to install, maintain, operate and/or replace them and are aware of the AOCs involved.

D. The OQ Plan should include language clearly indicating that covered tasks, whether performed in normal, abnormal or emergency situations, should be performed by qualified individual, or by others who are directed and observed by a qualified individual.

2. **§192.805 Qualification program.**

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(b.) Ensure through evaluation individuals performing covered tasks are qualified;

Re: §192.803 Definitions

***Evaluation* means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:**

...[list of permissible methods omitted]

***Qualified* means that an individual has been evaluated and can:**

(a.) Perform assigned covered tasks; and

(b.) Recognize and react to abnormal operating conditions.

A. The inspection revealed all employee evaluations currently assess only the knowledge component of the complete knowledge, skills and ability (KSA) "package" that demonstrates an individual can in fact perform those assigned covered tasks which may be physically and/or mentally challenging or have severe consequences if performed improperly.

B. The plan does not address a "cooling off" period between failing a knowledge test and being allowed to retake the test.

C. The various computer based training modules (CBTs) used for employee training and evaluations were developed by an independent vendor and may not reflect the procedures contained in SGG's own Operations, Maintenance and Emergency Response manual. The Plan should provide assurance there is a valid relationship between the evaluations conducted under this system and the procedures actually followed by the employees.

D. The plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified. Such individuals must present a certificate indicating their current competence to perform specialized work. In order to become "qualified", these individuals must also be evaluated on the AOCs the operator has defined as those which may be encountered during performance of the covered task.

3. **§192.805 Qualification program.**

(c.) Allow individuals not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

A. SGG's OQ Plan fails to provide any meaningful guidance to qualified individuals concerning to the number of non-qualified individuals they may "direct and observe" to accomplish a covered task. The ratio of qualified to non-qualified individuals is referred to as "span of control".

B. SGG's OQ Plan does not explain its use of various forms of the term "supervise", leaving that term open to individual interpretation. "Direct and observe" is the preferred term.

C. SGG's OQ Plan provided a list of tasks that a non-qualified "should" not perform, even if directed and observed by a qualified individual. The tasks listed are those which require specialized knowledge, training, skills and abilities and are appropriate to this category. However, the language should be strengthened (non-qualified individuals "must" not perform the tasks listed).

4. §192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(f.) Communicate changes which affect covered tasks to individuals performing those covered tasks;

A. SGG's OQ Plan currently addresses this topic over two sections, "Program Maintenance" and "Management of Change" (MOC). Those aspects addressing ordinary OQ program updates and modifications (e.g., changes that have no impact on the performance of covered tasks) should be addressed within the Program Maintenance section and plans for communicating those types of changes described therein. Changes fitting the criteria of paragraph (f) above (those affecting covered tasks) should be addressed within the MOC section. These changes should be categorized by their relative significance, which in turn should dictate how and when the changes are to be communicated to affected individuals.

B. The OQ Rule does not provide for a "grace" period during which non-qualified individuals may be evaluated on a covered task they are already performing without benefit of being directed and observed by a qualified individual. The MOC section of ETGS's OQ Plan must be integrated with the overall company's MOC process so coordination between Engineering, Operations, Maintenance and Regulatory departments may result in planning for required evaluations to produce qualified individuals in advance of the need.

5. §192.805 Qualification program.

(g.) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

A. The "Evaluation Intervals" portion of the SGG Plan describes a typical "difficulty, importance, and frquency" (DIF) analysis approach to assigning subsequent evaluation frequency, with rounding to the next highest whole number of years (limited to a maximum of 5 years). Additionally, the inspection revealed that SGG's intent was to evaluate individuals on infrequently performed tasks just prior to performance. However, an inspection of Appendix D (which maps the acceptable qualification methods to SGG's covered task list) reveals that all covered tasks were assigned an arbitrary 3-year interval.

B. The covered task list must be modified to reflect which infrequently-performed tasks will only require evaluations prior to performance. The remaining tasks (including those that may be added as a result of Item #1 above) should indicate a reevaluation interval supported by the rewritten "Evaluation Process" section of the Plan, which must reflect the actual intent of the new operator (ETGS).

When it is found an operator's procedures are inadequate, §192.603(c) provides the operator, after notice and opportunity for hearing under 49 CFR §190.211 (as provided for in 49 C.F.R. §190.237) may be required to amend its plans and procedures. This letter serves to provide you with notice of inadequate procedures and response options, as prescribed under §190.237. The operator is allowed thirty (30) days after receipt of such notice to submit written comments or to request a hearing. After considering the material presented in writing or at the hearing, the Office of Pipeline Safety is required to notify the operator the amendment is required as proposed, or to withdraw the notice proposing the amendment. If you do not desire to contest this notice, you must prepare the revised procedures and provide a copy to the Director, Southwest Region, within thirty (30) days of receipt of this notice.

Please refer to CPF No. 4-2005-2001M in any future correspondence on this matter.

Sincerely,

R. M. Seeley
Director, Southwest Region

Enclosure

UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
GAS PIPELINE SAFETY VIOLATION REPORT

A

1. Inspector Name	2. Date of Inspection	3. CPF#
Bob Brown	August 10-11, 2004	4-2005-2001M

4. Pipeline Operator/Owner
Original: Shell Gas Gathering, LLC (SGG) c/o Allan Schneider, V.P., Engineering & Operations
Current: Enbridge Transportation Group South (ETGS) c/o Rich Adams, V.P., Operations & Technology

5a. Headquarters Address	5b. Telephone No.
1100 Louisiana, Suite 3300, Houston, Texas 77002	713 / 821-2044
6. Inspection Location	**7. Inspection Unit**
1301 McKinney, Suite 700, Houston, Texas 77010	No. N/A of ALL

8. Portion of System Inspected (Describe location & facility)
OQ Program and Records only

9. Nature and Size of System

Number of Miles 1,013 (SGG, at the time of inspection)

Commodities Transported Natural Gas

Relevant Details with Respect to System: OQ Plan covered the primarily offshore pipeline assets of Shell Gas Gathering, which has been acquired by ETGS, a subsidiary of Enbridge, Inc. (based in Calgary, Canada).

10. Nature of Probable Violations (Check as many as applicable)

- ☐ 1. Problem in Design/Materials
- ☐ 2. Problem in Construction
- ☐ 3. Reporting Requirements
- ☐ 4. Test Requirements
- ☒ 5. Personnel Qualifications and Training
- ☐ 6. Anti-drug Program (More than 50 employees)
- ☐ 7. Other Operations
- ☐ 8. Corrosion Control
- ☐ 9. Pressure Control
- ☐ 10. Other Maintenance/Monitoring
- ☒ 11. Inadequate/No Procedures:
  - ☐ A. Construction
  - ☐ B. Corrosion Control
  - ☒ C. Operations
  - ☐ D. Training
  - ☒ E. Maintenance

RSPA Form GPS 101989

Report Submitted on: August 18, 2005

Violation No. 1

11a. CFR § Violated: 192.805(a)

11b. Summarize what the regulation requires that operator did not do:

SGG failed to include some covered tasks in it's "covered task list". It included at least one item that SGG did not perform (as that item applies only to local distribution companies). The "Glossary of Terms" had several erroneous entries that may have prevented some tasks from being included on the covered task list.

12. Provide detailed information about violation:

The Plan "Overview" section defines "operations and maintenance tasks" (part 2 of the 4 part test) so that only those items defined in subparts I, L & M of Part 192 may be considered. The rule's preamble was very clear about O&M tasks being dependent on other subparts of the code for performance criteria; this is why the 3rd part of the 4-part test reads "is performed as a requirement of this part" and not "..as a requirement of subparts I, L and M of this part". The "Glossary of Terms" also contains erroneous definitions which indicate that some tasks may have been wrongly excluded from the covered task list. Definitions provided in the regulations must be preserved as written, and not modified by an operator. The problematic definitions are:

- "Covered Task" - refers incorrectly to Part 195 instead of Part 192 (and essentially duplicates the definition given for "Four Part Test").
- "Four Part Test" - incorrectly indicates that Part 195 requirements apply to this gas-only operator.
- "Operations and Maintenance Tasks" - incorrectly indicates that "2. Emergency response activities are **not** Operations and Maintenance task[s]." Even though "emergency response" is not a covered task per se, the regulations addressing emergency response do fall within the operations and maintenance sections of the pipeline safety regulations and are therefore O&M tasks.
- "Performed on a Pipeline Facility" - contains a lot of verbiage not relevant to the given definition. The literal interpretation is: "activities taking place within the limits of the Pipeline Facility". Item 1 (definition of "Pipeline Facility") should quote §192.3 verbatim. Also, items 3 and 4 under have no bearing on this definition and should be deleted.
- "Tasks Performed on a Pipeline Facility" – ditto above; in addition, the phrase "physically connected to" is misleading (it implies that "pipeline" and "pipeline facility" are interchangeable terms). It should be replaced by the phrase "physically located within". For example, a gas controller and various items of SCADA equipment may be in a building located remotely from the "pipeline" (as defined in §192.3). However, that building (or that portion of it being used "in the transportation of gas" within a multiuse building) is still a part of the "pipeline facility" as defined in §192.3.

SGG indicated to the inspection team that Task #27, Atmospheric Corrosion, did not in fact cover "painting" an above-ground pipeline to protect it from atmospheric corrosion, clearly a covered task. There is no "Small pipe, fittings and tubing" task, which ensures that individuals recognize that these small items on high pressure pipelines can present extreme hazards if one is not competent to install, maintain, operate and/or replace them and are aware of the AOCs involved. On the other hand, Task #25 on the SGG CT list does not appear to be a task that SGG actually performs, as it applies only to gas distribution systems containing mains and service lines. The OQ Plan should also include language clearly indicating that covered tasks, whether performed in normal, abnormal or emergency situations, should be performed by qualified individuals, or by others who are directed and observed by a qualified individual.

13. Public and/or environmental concerns in area of violation:

Improper definitions inhibit a clear understanding of the rule's requirements by those implementing the OQ Plan. Misunderstandings permeate the entire organization and lead to inaccurate application of the rule's performance-based requirements. As a result, non-qualified individuals could be performing tasks which should have been deemed "covered", but were not due to the faulty definitions and misunderstandings.

14a. Persons Interviewed (partial list):

John Locantro **Title:** Regulatory Manager

Remy Daigneault **Title:** Superintendent

John Brennan **Title:** Superintendent

Tina Hollowell **Title:** Consultant (Regulatory Compliance Partners)

14b. Comments of persons interviewed:

SGG was receptive to making the requested changes, but were not likely to accomplish the task before the assets were sold. Their data room was open for prospective buyers at the time of the inspection. *The buyer turned out to be Enbridge, whose Transportation South affiliate we being OQ-inspected at the time the purchase agreement was announced.*

15. Supporting Documents/Materials			
Item No.	**Description (Include date)**	**Source of Documents**	**Remarks**
1	Pages 2 - 4 of SGG's OQ Plan (revised 07/15/04); "Identification of Covered Tasks"	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows the inaccurate definitions provided for the "Four Part Test" and includes the covered task list.
2	Pages 21-23 of SGG's OQ Plan (revised 07/15/04); "Glossary of Terms"	SGG's OQ Plan	This exhibit shows the remaining inaccurate definitions which may have resulted in the omission of some covered tasks

16. Inspector's Signature: Robert L. Brown Jr

Date: 5/9/06

Violation No. 2

11a, CFR § Violated: 192.805(b)

11b. Summarize what the regulation requires that operator did not do:

SGG's employee evaluations currently assess only the knowledge component of the complete knowledge, skills and ability (KSA) "package" that demonstrates an individual can in fact perform covered tasks which may be physically or mentally challenging. Even the knowledge evaluation is suspect in it's administration.

The plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified (as they are different from the typical "specialized" contractor discussed under "Contractor Qualifications").

12. Provide detailed information about violation:

The "Evaluation Process" section of SGG's OQ Plan and the "Evaluation Method" table indicates that only a knowledge test [an eWebOQ computer based training (CBT) module's evaluation test) is used to establish employee qualifications. This policy was confirmed by SGG. OPS views knowledge testing as only one of many options available to operators for evaluating an individual's qualifications. The "process" established by the operator (see the definition of "evaluation") must ensure that each evaluation fulfills the obligation to demonstrate that a candidate is capable of independently performing the task. Reliance on knowledge-only testing methods cannot convey this assurance, at least for difficult or critically important covered tasks.

The plan does not address a "cooling off" period between failing an evaluation test [a computer based training (CBT) evaluation module] and being allowed to retake the test. For example, one employee (John Brennan) was allowed to retake (and pass) an exam (eWebOQ Module 101, "Abnormal Operating Conditions") only 23 minutes after having failed in the first attempt. OPS recommends a minimum of 48 hours between a failed test and an opportunity to retake the test, to ensure that individuals are not depending on their "short term memory" to pass tests. A second test failure results in a supervisor "coaching" the individual on the particulars of the covered task, followed by subsequent evaluations (apparently without limit). OPS is concerned that this policy may confirm that SGG is only interested in the individual being able to pass a test, not in verifying the individual's ability to perform the task.

The plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified (as they are different from the typical "specialized" contractor discussed under "Contractor Qualifications"). Certificated contractor individuals must present a certificate indicating their current competence to perform specialized work (e.g., certificates are issued by NACE, ASNT, ClockSpring, API, welder testing processes, etc.). In order to become "qualified", these individuals must also be evaluated on the AOCs that the operator has defined as those which may be encountered during performance of the covered task(s) they are hired to perform. A successful AOC evaluation combined with a certificate of current competency form the documentation of that individual's qualification to perform the specialized covered task. Qualification of such individuals is important because the operator typically has no employee qualified to perform the covered task for which a certificated contractor was needed. An unqualified employee may not "direct and observe" a certificated, but unqualified, contractor perform that specialized covered task.

The use of contractor divers is a special case of particular interest to operators of offshore pipeline systems. SGG agreed at the inspection to begin educating divers about the AOCs that they may encounter on each job, and administering an oral examination to meet qualification requirements. This would supplement the normal "tailgate safety meeting" and "job safety analysis" that has historically been done prior to task performance.

13. Public and/or environmental concerns in area of violation:

When an operator fails to verify that "qualified" individuals can in fact perform each covered task they are assigned, there is cause for concern. Knowledge verification alone is insufficient to ensure that no errors in task performance will occur, especially with respect to those tasks which are complex, physically demanding, or have severe consequences if not performed correctly.

14a. Persons Interviewed (partial list):

John Locantro **Title:** Regulatory Manager

Remy Daigneault **Title:** Superintendent

John Brennan **Title:** Superintendent

Tina Hollowell **Title:** Consultant (Regulatory Compliance Partners)

14b. Comments of persons interviewed:

SGG was defensive about the lack of a "cooling off" period following the failure of a CBT evaluation. They indicated that "failures" were often due to an operator having to abandon a test to take care of operations on an offshore platform. The program would then show the test as having been failed when in fact it was only "not competed" (an insufficient number of questions had been answered correctly). OPS remains unconvinced; a 48 hour postponement should not present an unfair disadvantage, even to personnel working on platforms on a week on, week off basis. SGG was receptive to making the other requested changes, but were not likely to accomplish the task before the assets were sold. Their data room was open for prospective buyers at the time of the inspection. [Note: The buyer turned out to be Enbridge, whose Transportation South affiliate was being OQ-inspected at the time the purchase agreement was announced.]

15. Supporting Documents/Materials			
Item No.	**Description (Include date)**	**Source of Documents**	**Remarks**
3	Pages 6 – 7 of SGG's OQ Plan (revised 07/15/04); "Evaluation Process".	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that SGG relied entirely on knowledge testing to verify that an individual can "perform assigned covered tasks" [see §192.803 Definitions. *Qualified*, paragraph (a)].
4	Page 18 of SGG's OQ Plan)revised 07/15/04); "Contractor Qualifications"	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that the plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified (as they are different from the typical "specialized" contractor discussed under "Contractor Qualifications").
5	Page 26 of SGG's OQ Plan)revised 07/15/04) – Exhibit C, "Contractor Qualifications"	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit is included to supplement the allegations made in Item No. 4. Item No. 5 is a "special" case of the "Specialty Contractor" category, and addresses the use of "third party" (gas producer) employees on offshore producing platforms to perform covered tasks.

16. Inspector's Signature: Robert L. Brown Jr.

Date: 8/9/05

Violation No. 3

11a. CFR § Violated: 192.805(c)

11b. Summarize what the regulation requires that operator did not do:

SGG's OQ Plan provides little meaningful guidance concerning the performance of covered tasks by non-qualified individuals while under the direction and observation of a qualified individual.

12. Provide detailed information about violation:

Span of control (the number of non-qualified individuals that can be directed and observed by a single qualified individual) is only addressed within the last sentence of the single paragraph under "Non-Qualified Individuals". The qualified individual should be informed that it is he or she that will ultimately be held accountable for the proper performance of the covered task, which information also serves to limit span of control to a manageable level. The guidance must also specify that if the qualified individual must leave the immediate vicinity, performance of the task must cease until he or she resumes responsible charge.

The plan must provide specific guidance to qualified individuals regarding setting reasonable limits on span of control on a task-by-task basis. Those limits must consider the difficulty, importance and frequency of performance of the various covered tasks. Guidance must include examples of conditions which would warrant reducing the span of control from the established maximum. Such conditions should include (but are not necessarily limited to) the distance between the task participants (limited by the need to respond immediately if corrective action is needed); noise level (as it affects verbal communication); ambient lighting, environmental conditions (rain, fog, dusk, etc.) and line-of-sight obstructions (as they affect visual communication).

13. Public and/or environmental concerns in area of violation:

When an operator fails to provide it's "qualified" individuals adequate guidance concerning the number of non-qualified individuals that can be directed and observed in order to perform specific covered tasks without error, that provision of the OQ Rule is rendered meaningless. Results can vary from de facto prohibition from using non-qualified individuals (a violation of that portion of the rule) to using many more than can be adequately "directed and observed" to ensure that the work is performed properly in accordance with specifications. Improper task performance could result in incidents or accidents, either concurrent with the task performance or delayed in time (perhaps for years).

14a. Persons Interviewed (partial list):

John Locantro **Title:** Regulatory Manager

Remy Daigneault **Title:** Superintendent

John Brennan **Title:** Superintendent

Tina Hollowell **Title:** Consultant (Regulatory Compliance Partners)

14b. Comments of persons interviewed:

SGG had some good material, notably the requirement that the qualified individual take immediate correct action if necessary and to speak the language familiar to the non-qualified individual(s) if other than English. SGG also provided a list of covered tasks that non-qualified individuals "should not" be permitted to perform. SGG was receptive to making the requested changes, but were not likely to accomplish the task before the assets were sold. Their data room was open for prospective buyers at the time of the inspection. [Note: The buyer turned out to be Enbridge, whose Transportation South affiliate was being OQ-inspected at the time the purchase agreement was announced.]

15. Supporting Documents/Materials			
Item No.	**Description (Include date)**	**Source of Documents**	**Remarks**
6	Page 10 of SGG's OQ Plan (revised 07/15/04); "Non-Qualified Individuals".	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that SGG relied entirely on qualified individuals and their supervisors to interpret spans of control for the various covered tasks.

16. Inspector's Signature: Robert L. Brown Jr. **Date:** 8/9/05

Violation No. 4

11a. CFR § Violated: 192.805(f)

11b. Summarize what the regulation requires that operator did not do:

Changes affecting the performance of covered tasks should be categorized by significance and communicated to affected entities in a manner commensurate with that significance.

12. Provide detailed information about violation:

SGG's OQ Plan fails to separate programmatic changes (which should be included in the "Program Maintenance" section) from those changes which affect the performance of covered tasks [which should be included in the "Management of Change" (MOC) section]. Such separation would enhance the ability of readers to locate the information pertinent to each category.

The MOC section should categorize changes by significance, which in turn should dictate how the changes are to be communicated to affected individuals (employees, contractors, and third parties).

- Major changes are those which require a new evaluation, either because a new task has been introduced, or because existing evaluation criteria have changed significantly (thus requiring a reevaluation on a previously existing task). These changes should be communicated to affected individuals and evaluations performed prior to their next performance of the covered task.
- Minor changes (e.g., a change in the sequence of task performance steps) require timely notice to affected parties, but no evaluation or reevaluation is needed.
- Plan or covered task wording changes that have no impact on covered task performance may be communicated at upcoming safety meetings, job kick-off meetings, letters to contractors, etc.

The MOC section should clearly indicate that major changes require that individuals be evaluated and deemed qualified prior to allowing them to perform that covered task independently. For example, a new item of equipment (a pipeline component with which the operator has had no prior experience) may not be made operational until someone has been qualified to operate and maintain it. In this case, it would likely be the equipment vendor who furnishes operator training and evaluation service. The operator's program should recognize the vendor as an expert in the field, and accept the qualification training administered by the vendor (which must include any AOCs specifically associated with the maintenance and operation of that particular item of equipment). Once the vendor's training is complete (either in the manufacturing facility or during on-site simulation of actual use), individual evaluations may be performed (tests of knowledge, skills and abilities, as necessary) and each trained individual's qualification to operate it documented.

13. Public and/or environmental concerns in area of violation:

When an operator fails to provide current information pertaining to the performance of a covered task to the "qualified" individuals responsible for performing the task, the opportunity for incidents or accidents is increased.

14a. Persons Interviewed (partial list):

John Locantro **Title:** Regulatory Manager

Remy Daigneault **Title:** Superintendent

John Brennan **Title:** Superintendent

Tina Hollowell **Title:** Consultant (Regulatory Compliance Partners)

14b. Comments of persons interviewed:

SGG was receptive to making the remaining requested changes, but were not likely to accomplish the task before the assets were sold. Their data room was open for prospective buyers at the time of the inspection. [Note: The buyer turned out to be Enbridge, whose Transportation South affiliate was being OQ-inspected at the time the purchase agreement was announced.]

15. Supporting Documents/Materials			
Item No.	**Description (Include date)**	**Source of Documents**	**Remarks**
7	Pages 15 - 17 of SGG's OQ Plan (revised 07/15/04); "Program Maintenance" and "Management of Change".	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that SGG has inadequate instructions to individuals governed by the Plan to recognize and differentiate significant changes (those affecting how a covered task is performed) from less significant changes.

16. Inspector's Signature: Robert L. Brown Jr

Date: 8/9/05

Violation No. 5

11a. CFR § Violated: 192.805(g)

11b. Summarize what the regulation requires that operator did not do:

Reevaluation intervals should vary by covered task, based on a difficulty, importance and frequency of performance basis (a "DIF" analysis). Contrary to SGG's plan wording and information provided during the inspection, all tasks were assigned a 3-year reevaluation interval.

12. Provide detailed information about violation:

The last page of the section titled "Evaluation Process" of SGG's Plan addresses "Evaluation Intervals". This page describes a typical DIF analysis approach, with rounding to the next highest whole number of years (limited to a maximum of 5), to assigning subsequent evaluation frequency. However, an inspection of Appendix D (which maps the acceptable qualification methods to SGG's covered task list) reveals that all covered tasks have been assigned an arbitrary 3-year interval. A fixed 3-year interval makes no distinction between the qualifications required to perform mundane tasks versus those required of individuals performing tasks critical to the safe operation of the pipeline, such as Gas Control (Task #49).

The Plan fails to take into account the fact that some tasks require different intervals on the "competency to perform" portion of the 2-part qualification requirement for certificated individuals. Examples include welding on steel pipelines (6 months); plastic pipe fusion and ClockSpring (1 year); ASNT and NACE (5 years). The Plan also failed (according to SGG's consultant, present at the inspection) to incorporate the intent to evaluate infrequently-performed tasks just prior to performance, not on a regular basis (e.g., hot taps would fall in this category). The "Frequency (years)" column of Appendix D must be modified to reflect which tasks will be evaluated "prior to performance". The remaining tasks (including those that may be added as a result of Violation #1) should indicate a reevaluation interval that is supported by the rewritten "Evaluation Process" section of the Plan.

The "Evaluation Intervals" portion of the SGG Plan must be rewritten to reflect the actual intent of the operator (now ETGS) as it is made to correct the observed deficiencies and inconsistencies of it's own (and SGG's) plan.

13. Public and/or environmental concerns in area of violation:

When an operator fails to provide current information pertaining to the performance of a covered task to the "qualified" individuals responsible for performing the task, the opportunity for incidents or accidents is increased.

14a. Persons Interviewed (partial list):

John Locantro **Title:** Regulatory Manager

Remy Daigneault **Title:** Superintendent

John Brennan **Title:** Superintendent

Tina Hollowell **Title:** Consultant (Regulatory Compliance Partners)

14b. Comments of persons interviewed:

SGG was receptive to making the remaining requested changes, but were not likely to accomplish the task before the assets were sold. Their data room was open for prospective buyers at the time of the inspection. [Note: The buyer turned out to be Enbridge, whose Transportation South affiliate was being OQ-inspected at the time the purchase agreement was announced.]

15. Supporting Documents/Materials			
Item No.	Description (Include date)	Source of Documents	Remarks
8	Page8"Evaluation Intervals" and Appendix D "Third party Qualification Method Mapping to SGG Operator Qualification Tasks" of SGG's OQ Plan (revised 07/15/04)	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that SGG was inconsistent in applying it's methodology for establishing reevaluation intervals, and did not account for tasks requiring differing intervals based on technical competency requirements.
9	"Appendix D" to SGG's OQ Plan (an Excel spreadsheet containing 3 pages, Revision date 07/28/04)	SGG's OQ Plan, provided by John Locantro for this inspection	This exhibit shows that SGG provided instructions (in Exhibit 8) for establishing reevaluation intervals that were not followed. In addition, the intervals were established at an arbitrary 3 years for all covered tasks, rather than as established by the written procedure.

16. Inspector's Signature: Robert L. Brown Jr **Date:** 8/9/05

17. Compliance History Describe Violation / CPF No.				
Date	**Place**	**Noncompliance**	**Date WL**	**Outcome**
SEE	ENCLOSED	LIST OF CPF HISTORY	DETAILS	Various

18. Gravity of Offense

About average for this size operator; the "intent to comply" was there but fell short of "OQ2" expectations re: defining the basis for understanding the conditions necessary to ensure a complete capture of all compliance expectations for a largely performance-based rule.

19. Degree of Culpability

Uncontested.

20. Ability to Continue in Business

This operator's assets and management team have been merged into another operator, Enbridge Transportation Group South. That operator has it's own enforcement action pending relating to OQ. Neither action will have any effect on it's ability to continue in business.

21. Ability to Pay

Not at issue, as no CP is proposed.

22. Good Faith in Attempting to Achieve Compliance

SGG had several potential issues raised as a result of the mistakes made in their OQ Program. All the mistakes were typical of those made by operators who tried to interpret the rule's requirements without benefit of understanding the positions publicized by OPS during the four public meetings held during 2003 and subsequently posted on the OQ Website, http://primis.rspa.dot.gov/oq/index.htm. This is in spite of the Regulatory Manager's indication that he attended two of the public meetings, and had hired a consultant (Regulatory Compliance Partners) to help write the OQ Plan.

23a. Proposed Remedy

- ☐ **Warning Letter**
- ☐ **Civil Penalty: Recommended Amount $** xx,000.00
- ☐ **Compliance Order**
- ☐ **Hazardous Facility Order**
- ☒ **Notice of Amendment of O&M Plan**

23b. Analysis of Proposed Remedy

Violation 1 was a failure to ensure that "qualified" individuals could in fact independently perform (without being directed and observed by a qualified individual) assigned covered tasks. The plan also failed to set out qualification requirements for "certificated" individuals, including divers (a necessity for offshore operations). The remedy requires Enbridge to ensure that the plan provides that all employees, contractors and third parties who independently perform covered tasks on behalf of it's affiliates be properly "qualified", as that term is defined in §192.803 and §195.503.

Violation #2 was one of failure to present accurate definitions and the explanatory information necessary to properly interpret the performance requirements of §192.80(a). SGG translated a set of eWeb OQ training and evaluation modules into their own defined covered task list. As a result, a few tasks were "missed" and at least one was included that should not have been (as they did not perform that task). The remedy requires Enbridge to ensure that the plan that applies to its affiliates includes the missed tasks and deletes those which are not applicable to their operations.

Violation #3 was a failure to provide meaningful guidance to qualified individuals concerning the number of non-qualified individuals they may "direct and observe" in order to accomplish a covered task (referred to as "span of control"). The remedy requires ETGS to set specific, reasonable limits on span of control ratios on a task-by-task basis. For each task, the limit set must consider complexity, the consequences of improper performance, and frequency of performance. Ratios may vary all the way down to 1:0 (indicating that task will not be performed by a non-qualified individual). Guidance must provide examples of conditions which could warrant reducing the span of control, and must specify that if the qualified individual leaves the immediate area, performance of the covered task must cease until a qualified individual returns. The plan should also inform qualified individuals that they will be held accountable for the proper performance of the task.

Violation #4 involved inadequate covered task management of change procedures, which were intertwined with less important program maintenance changes. The remedy requires that the MOC section of ETGS's OQ Plan be integrated with the overall company's MOC process so that coordination between Engineering, Operations, Maintenance and Regulatory departments may result in planning for required evaluations to produce qualified individuals in advance of the need.

Violation #5 addressed SGG's failure to establish evaluation intervals that were commensurate with task complexity and criticality, or that recognized that certificated individuals have their certifications renewed on schedules which conflict with the arbitrarily selected 3-year subsequent evaluation interval. The remedy requires ETGS to clearly state the premises for establishing evaluation intervals, and to establish them in accordance with those premises, respecting the objections raised by OPS to prior attempts by both SGG and ETGS.

24. Region Director's Signature: **Date:**

R. M. Seeley 8/18/05

Director, Southwest Region

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 1 - SGG's OQ Plan, pages 2 - 4 of 28, Revision date 07/15/04		
Evidence	Obtained from	Identifying Witness
This exhibit shows the inaccurate definitions provided for the "Four Part Test" and includes the covered task list.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 2

IDENTIFICATION OF COVERED TASKS

Overview

The Operator has the responsibility for identifying covered tasks according to the Four-Part Test prescribed by the DOT Operator Qualification Rule. The covered task list was condensed from an initial task pool that was identified as a direct result of a thorough review of 49 CFR Parts 192 and 195 and a comprehensive study of all tasks performed on SGG's pipeline systems. The Four-Part test was applied to each task in the initial pool to determine tasks covered by the Operator Qualification Rule. See Appendix "E" for tasks that were considered but determined not to be covered.

The Four-Part Test provides that a covered task is one that meets each of the following four criteria:

1. The task is performed on a pipeline facility;
2. Is an operations or maintenance task as defined in subpart L or M of the regulation (and subpart I in regards to corrosion control and monitoring activities);
3. Is a task performed specifically as a requirement of 49 CFR 192; and
4. The task affects the operation or integrity of the pipeline.

Process to Determine if Task is Covered

Anytime a new activity is performed on the pipeline that may be considered covered, it must be given the 4-part test to determine applicability to the Operator Qualification Program. If it is determined that this is a new covered task, evaluation tools must be written and individuals must be qualified prior to performing the task. A MOC should also be issued to all personnel concerned.

If it is determined that a task or part of a task is no longer being performed on covered facilities the OQ Program should be documented in Appendix "E" with the other tasks that were considered but determined not to be covered.

Covered Tasks

1. Prevention of Accidental Ignition and Potential Ignition Sources – 49 CFR 192.75 1
2. Recognize and react to Abnormal Operating Conditions and Safety Related Conditions – 49 CFR 192.605(c) and 192.503.
3. Emergency Plans and Public and Contractor Education – 49 CFR 192.615 and 192.616
4. Excavation and Backfilling Safety – 49 CFR 192.319, 192.327, 192.605(b)(9) & 192.614
5. Pigging Pipelines – 49 CFR 192.605
6. Leak Surveys and Leak Classification – 49 CFR 192.5, 192.613, 192.614, 192.705, 192.706, 192.707, 192.709, 192.721 and 192.723
7. Pipeline Patrol and Population Density Determination – 49 CFR 192.5, 192.459, 192.607, 192.609, 192.611, 192.705, 192.706, 192.707, 192.721 and 192.723

8. Odorization – 49 CFR 192.624
9. Inspect Buried Pipe when Exposed – 49 CFR 192.455, 192.461, 192.465, 192.479 and 192.481
10. Leak Investigation – 49 CFR 192.617
11. Pipeline Failure Investigation – 49 CFR 192.613 and 192.617
12. Damage Prevention: Locating and Marking Pipeline Facilities – 49 CFR 192.614 and 192.616
13. Valve Operator Maintenance – 49 CFR 192.745 and 192.747
14. Valve Maintenance – 49 CFR 192.745 and 192.747
15. Valve Inspection – 49 CFR 192.745
16. Inspecting and Testing Regulators, Relief valves and Control Valves – 49 CFR 192.199, 192.201, 192.731, 192.739 and 192.743
17. Pressure Testing Steel and Plastic Pipelines – 49 CFR 192.503, 192.505, 192.507, 192.509, 192.511, 192.513, 192.515, 192.717, 192.725 and 192.727
18. Pipeline Leak Repair – 49 CFR 192.711, 192.713, 192.715, 192.717 and 192.719
19. Pipeline Purging – 49 CFR 192.629
20. Hot Tapping and Stopping – 49 CFR 192.627
21. Up-rating Pipeline Systems – 49 CFR 192.551, 192.553, 192.555 and 192.557
22. Abandonment of facilities – 49 CFR 192.727
23. Installation of Anodes – 192.475[b], 192.477 and 192.605[b][10][ii]
24. Pipeline Shutdown and Startup – 192.605
25. Installation of Steel Mains and Services – 49 CFR 192.361, 192.363, 192.365, 192.367 and 192.371
26. Vault Inspection and Entry Procedures – 49 CFR 192.749
27. Atmospheric Corrosion – 49 CFR 192.479, 192.481, 192.485, 192.461, 192.483, 192.487, 192.489 and 192.491
28. Cathodic Protection Troubleshooting – 49 CFR 192.463 and 192.465
29. Cathodic Protection - Rectifier Inspection – 49 CFR 192.463 and 192.465
30. Protective Coatings – 49 CFR 192.561
31. Installation of Test Stations – 49 CFR 192.463, 192 469 and 192.471
32. Conduct Annual Cathodic Protection Survey – 49 CFR 192.463
33. Electrical Insulator Inspection and Testing Casings – 49 CFR 192.467
34. Internal Corrosion Monitoring – 49 CFR 192.475, 192.477 and 192.605[b][10][ii]
35. Inspect Internal Pipe Surfaces – 49 CFR 192.475
36. Interference (AC and DC) – 49 CFR 192.467 and 192.473
37. Pipe-to-Soil Surveys – 49 CFR 192.465
38. Electric Arc Welding – 49 CFR 192.231, 192.233, 192.235, 192.241[a][b][c], 192.243 and 192.245[a][b]
39. Welder Qualifications – 49 CFR 192.255[a], 192.227 and 192.229
40. Weld Repairs and Welding Procedures – 49 CFR 192.241 and 192.245
41. Compressor Station Operations and Safety – 49 CFR 192.605

42. Compressor Station Operations-Reciprocating Units – 49 CFR 192.605[b][6][7][8]
43. Compressor Station Operations-Turbine Units – 49 CFR 192.605[b][6][7][8]
44. Inspecting and Testing of Relief valves or Devices at a Compressor Station – 49 CFR 192.731
45. Inspecting and Testing of the Gas Detection System at a Compressor Station – 49 CFR 192.736
46. Testing Emergency Shutdown Devices – 49 CFR 192.745
47. Inspection Activities for Tie-ins, Pipe replacements or other components connecting to an existing pipeline
48. Subsea Pipeline Inspection – 49 CFR 192.xxx
49. Gas Control

Abnormal Operating Conditions

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) indicate a condition exceeding design limits; or

(b) result in a hazard(s) to persons, property, or the environment.

Abnormal Operating Conditions (AOCs) have been written to imply the initial statement "recognize and respond to".... Thus, the AOC is written as "Leak from pipeline / tank". The implied statement is "Recognize and respond to leak from pipeline / tank".

Abnormal Operating Conditions (AOCs) include:

1. things that conceivably could go wrong during the task
2. things that could go wrong as a result of the task
3. things not directly related to the normal performance of the task that could be discovered to be wrong when performing the task

Note that these things do not necessarily meet the strict definition of Abnormal Operating Conditions as defined by the regulation. However, they ARE all things that a qualified person should be able to "react and respond to" when performing the task.

Abnormal Operating Conditions (AOCs) do not include:

1. doing a task incorrectly
2. not meeting the specifications or requirements related to the task
3. things that are NORMALLY checked and corrected during performance of the task (e.g. - "transmitter out of calibration" is not an AOC if the task is to "calibrate the transmitter")

Although some tasks have specific abnormal operating conditions that pertain only to that task or that task type, there are many AOCs that apply to all tasks and all qualified personnel should be able to recognize and respond to them. These are listed on the following page. Part of the evaluation process will include provisions to ensure employees and contractors know how to recognize and respond to these conditions.

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 2 - SGG's "Glossary of Terms", pages 21 - 23 of 28, Revision date 07/15/04		
Evidence	Obtained from	Identifying Witness
This exhibit shows the inaccurate definitions provided for "Covered Task", the "Four Part Test", "Operations and Maintenance Tasks" and "Tasks Performed on a Pipeline Facility".	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 2

Glossary of Terms

Abnormal Operating Condition

A condition identified by the Company that may indicate a malfunction of a component or deviation from normal operations that may indicate an operating condition that exceeds design limits or results in hazard (s) to person, property or the environment. Some examples of AOC's may include but are not limited to:

1) Unexpected hydrocarbon encounter (release, spill, hazardous atmosphere, and contamination)
2) Unexpected pressure deviations (increase, decrease, high, low or absent)
3) Activation of any safety device (relief valve, ESD, high pressure shutdown and high temperature shutdown).
4) Unexplained flow rate deviations (high flow, low flow, no flow).
5) Unexplained status change (unit start up, unit shut down, valve open, valve close, temperature change, flash, haze, co-mingling of products).
6) Fire / Explosion within the vicinity of the pipeline.
7) Interruption or failure of communications / Control system / Power
8) Pipeline system damage (line hit, lighting strikes, tornado, flood, hurricane, or earthquake).
9) Component Failure or Malfunctioning component (field and SCADA components including meter failure)
10) Abnormal facility condition (e.g.: exposed pipe, low CP levels, missing markers, atmospheric corrosion).

NOTE: A deviation from normal operations does not necessarily mean an abnormal operating condition exist as long as conditions are within the parameters identified by the company.

Covered Task

An activity by an individual or a group of individuals that (a) is performed on a pipeline facility and; (b) is an operations and maintenance task and; (c) is required by part 195; and (d) effects the operation or integrity of the pipeline.

Evaluation

A process established and documented by the Company, to determine whether an individual is qualified to perform a cover task.

Four Part Test

A test that is applied to any task to determine if it meets the requirements of a "covered task" for the purposes of this program. A task must meet ALL FOUR of these conditions to be considered a covered task. The four parts of the test are:

1. Is the task performed on a pipeline facility,
2. Is the task associated with operations or maintenance,
3. Is the task required by Part 192 or 195, and
4. Does the task affect the operation or integrity of the pipeline?

Grandfathered Employees

Employees performing DOT related tasks as of October 27, 1999. The initial evaluation of these employees can consist solely of work performance history review.

Individual

A person, who on behalf of the company, performs one or more covered task on a pipeline facility operated by the company.

Incident

Any of the following events:

- An event that involves a release of gas from a pipeline and
  - A death, or personnel injury necessitating in-patient hospitalization, or
  - Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more
- An event that is significant, in the judgment of the operator

Initial Qualification

Qualification, at any time, of individuals for the first time under this program.

Maintenance

Maintenance is the process of maintaining property or equipment, including pipelines, to preserve it and prevent it from failure and ensure that it will continue to perform its intended function.

Management	Area Operations Manager, the Operations, Regulatory Manager and the Vice President, Engineering & Operations
New Construction	Construction of a new pipeline that is not simply a replacement or repair of a pre-existing pipeline. Tasks associated with new construction are not typically "covered tasks", except for tie-ins and/or construction being conducted in close proximity to existing covered pipeline facilities.
Operate	Start, stop, open, close and monitor
Operations and Maintenance Tasks	Activities done by an individual or group of individuals (a) to perform a function on a pipeline facility; or (b) to upkeep of a pipeline facility. 1. A "New construction task" changes to an operations and maintenance task when the pipeline facility is being commissioned or during the act of connecting to an active pipeline facility. 2. Emergency response activities are **<u>not</u>** Operations and Maintenance task. 3. Activities on pipelines that have never been in service or pipelines that are isolated or physically not connected to a source of hazardous liquid or fabrication of new installations are not Operation and Maintenance task.
Performed on a pipeline facility	An activity that is performed by an individual or group of individuals whose performance directly impacts the pipeline facility. 1. **Pipeline Facility** is new and existing pipe, right of ways and any equipment, facility or building used in the transportation of a hazardous liquid or gas. 2. **Activity** means physical, visual, or mental effort directed at achieving a results. 3. Removed from the system means that part of the pipeline system is physically removed or isolated from the pipeline system. 4. Pipeline System means all parts of a pipeline facility through which a hazardous liquid moves in transportation (line pipe, valves, appurtenances, pumps, meters, tanks, etc.).
Performing Covered Task	Effect October 28, 2002, before any contractor can personnel can perform a covered task on any pipeline facility, the Company will: • Ensure that contractor complies with OQ requirements, regulations and Company requirements • Verify that contractor personnel are qualified to perform specific applicable covered task via the API/NCCER qualification and NCCER National Registry programs. • Perform random audits of contractors OQ compliance process.
Qualified Individual	An individual is evaluated and • Can perform assigned covered task • Can react to abnormal operating conditions • Compliance documentation has been completed
Subsequent Qualification	Re-evaluation of an individual's qualifications, after the initial qualification, at the interval established by the operator.
Tasks Performed on a Pipeline Facility	An activity that is performed on a pipeline component that is physically connected to the pipeline facility. Note that pipeline components that have been physically removed from the pipeline facility, such as relief valves that are sent to a shop for repair, are no longer considered to be "on" the pipeline facility, and tasks performed on those components while not physically connected to the pipeline facility are not "covered tasks".

Third Party Entities

Any other entity that performs covered tasks on the pipeline. These will be considered as contractors for the purpose of this plan.

Transitional Qualification

Qualification completed by October 28, 2002, of individuals who have been performing a covered task on a regular basis prior to the effective date of the rule, October 27, 1999.

Work Performance History Review

An evaluation of a person's prior performance on the job in order to establish their qualification to perform that job. This type of evaluation does not require any input or feedback from the person whose prior performance is being evaluated.

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 3 - Pages 6 – 7 of SGG's OQ Plan, Revision date 07/15/04		
Evidence	Obtained from	Identifying Witness
This exhibit shows that SGG's employee evaluations assess only the knowledge component of the complete knowledge, skills and ability "package" needed to show that someone can perform a covered task.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 3

EVALUATION PROCESS

Overview

The operator must ensure through evaluation that individuals performing covered tasks are qualified. Qualified means that an individual has been evaluated and can perform the covered task and can recognize and react to abnormal operating conditions. All employees and contractors performing covered tasks after October 28, 2002 will be qualified or supervised by someone who has been qualified.

Evaluation means a process established and documented by SGG to determine an individual's ability to perform a covered task by any of the following:

a) written examination,
b) oral examination,
c) work performance history review,
d) observation of employee while performing the covered task,
e) performance on the job performing the covered task,
f) on the job training,
g) simulations (computer based eWebOQ), or
h) some other form of assessment.

Shell Gas Gathering will use the attached form listed as Exhibit "A" to document the written or oral evaluation of individuals for a covered task. Individuals qualified through computer-based evaluation (eWebOQ) will have that evaluation documented using the various eWebOQ training reports (Exhibit "B"). These records will be maintained for a period of 5 years at the local field office along with other DOT inspection documentation records.

Evaluation Method	"Transitional Qualification"	"Initial Qualification"	"Subsequent Qualification"
Written Exam	YES	YES	YES
Oral Exam	YES	YES	YES
Work performance history review	YES As long as employee was successfully performing work October 26, 1999	May not be used as the sole evaluation method	May not be used as the sole evaluation method after October 28, 2002
Performance on the job	YES	NO	NO
On-the-job training	YES	NO	NO
Simulation (Computer Based eWebOQ)	YES	YES	YES
Other	YES	NO	NO

These methods will be consistently applied and all individuals performing the same covered task will be evaluated using consistent methods.

Transitional Qualification

Transitional Qualification applies to those individuals who were hired by SGG prior to the implementation of the Operator Qualification Program and performed the designated covered task on behalf of SGG prior to October 26, 1999. SGG qualified these individuals by having them complete the EWebOQ CBT Modules.

If the individual is unsuccessful at fulfilling all of the requirements for the transitional evaluation process for the designated covered task, the individual cannot be re-evaluated according to this process. The individual may however be evaluated according to the Initial Evaluation Process.

Initial Evaluation Process

Initial evaluation applies to those individuals who do not currently possess a qualification for the designated covered task and have never possessed a qualification for the covered task. Prior to evaluation, these individuals will be paired with a qualified person to gain on the job training for each covered task for which they are to be evaluated. Once the Qualified Person determines the individual is ready for evaluation, his Supervisor will perform the evaluation. An individual may qualify for a covered task by successfully passing (with a score of 80%) the respective written, oral or computer exam for that designated covered task. If the initial evaluation process for a specific covered task results in an evaluation status of unsuccessful, the individual may be evaluated again at his own discretion. If the second evaluation process results in an unsuccessful evaluation, any subsequent evaluations will be administered in the following manner:

1. The Operations-Regulatory Manager will notify the individual's direct supervisor (either the Operations Superintendent or Operations Foreman) that the individual's evaluation for a specific covered task has been unsuccessful.
2. The supervisor will call the individual into the respective area office and in a one-on-one setting "coach" the individual regarding the particulars of the specific covered task. This coaching may involve both classroom and field instruction.
3. When the supervisor is satisfied that the individual has mastered the specific covered task, he will proctor the individual during subsequent evaluations of the covered task to be given in the respective area office.

Subsequent Evaluation Process

Subsequent evaluation applies to those individuals attempting to be re-evaluated in a specific covered task. Subsequent evaluation is performed following the same procedures as initial evaluation.

U.S. Department of Transportation
Office of Pipeline Safety
Southwest Region

EXHIBIT TAB

Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC

Exhibit No. 4 - Page 18 of SGG's OQ Plan, Revision date 07/15/04 - "Contractor Qualifications"

Evidence	Obtained from	Identifying Witness
This exhibit shows that the plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified (as they are different from the typical "specialized" contractor discussed under "Contractor Qualifications").	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission

Investigator Name: Bob Brown Title: General Engineer

Exhibit 4

CONTRACTOR QUALIFICATIONS

SGG utilizes contractors that are qualified under this plan and also contractors who provide their own qualifications. The contractors providing their own qualifications will be considered "Specialty Contractors" for the purposes of this plan. The contractors qualified under this plan will be treated like SGG employees. There are also third party entities that perform covered tasks on the pipelines due to their location (i.e. – owners of platforms). These individuals will be treated as Specialty Contractors for the purposes of this plan. Exhibit C of this plan further describes these third party entities and how they were qualified.

It is the responsibility of the Specialty Contractor to provide qualified, competent workers under the terms of its specific contract with SGG. SGG will not assess nor will it evaluate the competencies of the Contractor employees to perform covered tasks. A Specialty Contractor must qualify its employees through either the National Center for Construction, Education and research (**"NCCER"**) or the Operator Qualifications Solutions Group (**"OQSG"**) and insure that all of the Specialty Contractor employees who perform covered tasks on behalf of SGG are qualified to perform those tasks or will be directly supervised by someone who is qualified to perform those covered tasks.

Specialty Contractors must subscribe to ISNetworld. The Contractor provides qualification information to ISNetworld prior to working for SGG. This will allow SGG to check contractor qualifications online. ISNetworld has incorporated the information matrix in Exhibit D into its database.

Upon review of the information provided by the Contractor (via ISNetworld), SGG Management will designate as qualified under its Operator Qualification program those Contractor employees that it deems acceptable. This designation lasts for the duration of the contract or for a maximum of three years, whichever is less.

Prior to a Specialty Contractor beginning work on the pipeline or pipeline facility, a SGG representative will ensure that the individual knows how to recognize and respond to any AOCs that may happen at this facility. This will be done at least once each evaluation period for ongoing jobs or for Specialty Contractors that regularly perform the covered task at the facility.

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 5 - Page 26 of SGG's OQ Plan, Revision date 07/15/04 – Exhibit C, "Contractor Qualifications"		
Evidence	Obtained from	Identifying Witness
This exhibit is included to supplement the allegations made in Exhibit No. 4. Exhibit No. 5 is a "special" case of the "Specialty Contractor" category, and addresses the use of "third party" (gas producer) employees on offshore producing platforms to perform covered tasks.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 5

Exhibit C
Contractor Qualifications

Shell Gas Gathering, LLC uses third party entities to perform certain covered tasks on some of its offshore pipelines. Those entities, the tasks they perform and the locations are described below.

Shell Exploration & Production Company - SEPCo

SEPCo operates several production platforms where SGG pipelines originate. At these locations SEPCo performs the following covered tasks:

- Launching and receiving of pigs
- Testing of relief valves
- Testing of mainline valves

The SEPCo locations where these tasks are performed are:

- GB 128 "A"
- GC 65 "A"
- WD 143 "A"

SEPCo used OQSG evaluation modules to qualify their employees. SGG has reviewed those modules relevant to the tasks performed on our lines and approve them under this plan. SGG has been provided records of these evaluations. SEPCo will annually provide SGG with any updates to their qualification plan / methods and records of qualified individuals.

BP Pipeline Company (BP)

BP operates the MP 260 "P" platform. SGG's Spirit Pipeline (MMS Segment No. 11680) terminates at this platform. At this location, BP performs the following covered tasks:

- Receiving of pigs
- Testing of relief valves
- Testing of mainline valves

BP prepares employees for testing using study guides, OJT and other equivalent means. Then they are given a written and practical evaluation for an initial evaluation. Re-qualification will only require written evaluations with practical tests being optional. If the employee scores 100% he is qualified for the covered task, if he scores between 70% and 99% the evaluator reviews the answers with the employee for clarity and assumes responsibility for proficiency. 100% after review will allow the employee to be qualified anything less or an initial score less than 70% and the employee fails the qualification. Employees who fail the qualification are treated as follows:

- 1st and 2nd Attempts: Placed in "non-qualified status" and attends personalized training. Afterwards, he is evaluated again.
- 3rd Attempt: The employee is considered unable to perform assigned task and disciplinary action for non-performance will apply.

All other Specialty Contractors will qualify their employees through NCCER or OQSG and will subscribe to ISNetworld to maintain their qualification records.

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 6 - SGG's treatment of "Non-Qualified Individuals", page 10 of 28, Revision date 07/15/04		
Evidence	Obtained from	Identifying Witness
This exhibit shows that SGG relied entirely on qualified individuals and their supervisors to interpret spans of control for the various covered tasks.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 6

NON-QUALIFIED INDIVIDUALS

Allow individuals that are not qualified pursuant to the evaluation process to perform a covered task if directed and observed by an individual that is qualified.

SGG will in some cases utilize temporary employees or contract personnel that are not documented in our Operator Qualification program to perform covered tasks. This will be acceptable, as defined in 192.805(c), only while under the close supervision of an individual who possesses a current qualification for the designated covered task. The supervising individual must be able to direct the actions of the individual performing the covered task and must be able to take immediate corrective action, if necessary. The Qualified individual must be able to communicate with the non-qualified individual even if he speaks and comprehends a language other than English. The number of non-qualified individuals that can be directly supervised by a qualified individual is dependent on the severity of the task.

A non-qualified individual should not perform the following tasks:

- #12 Damage Prevention: Locating and Marking Pipeline Facilities
- #20 Hot tapping and Stippling
- #21 Conduct Annual Cathodic Protection Survey
- #28 Cathodic Protection Troubleshooting
- #29 Cathodic Protection – Rectifier Inspection
- #38 Electric Arc Welding
- #39 Welder Qualifications
- #40 Weld Repairs and Welding Procedures
- #47 Inspection Activities for Tie-ins, Pipe Replacements, or Other Components Connecting to an Existing Pipeline.
- #48 Subsea Pipeline Inspection

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 7 - SGG's treatment of "Program Maintenance" vs. ""Management of Change, pages 15 - 17 of 28, Revision date 07/15/04		
Evidence	Obtained from	Identifying Witness
This exhibit shows that SGG has inadequate instructions to individuals governed by the Plan to recognize and differentiate significant changes (those affecting how a covered task is performed) from less significant changes.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 7

Program Maintenance

The program must be updated when:

- Pipeline Operations are changed in ways that affect this program
- Pipeline Equipment and Facilities are changed in ways that affect this program, including the use of new equipment and new technology
- Employee Job Descriptions are changed in ways that affect this program
- Written Procedures for covered tasks are added, deleted, or modified
- Company Organization is changed in a way that affects this program
- Company Policies are changed in a way that affects this program
- Training Offered / Required changes
- Regulations involving covered task are changed in a way that affects this program

Whenever there is a change such as described above that may affect this program, the following will be done:

1. The program will be evaluated to determine the effect.
2. Work procedures will be modified / created as necessary.
3. Evaluation tools will be modified / created as necessary.
4. The written plan will be modified as necessary.
5. Meetings will be held with affected personnel to inform them of the changes. Changed procedures will be handed out at this time. Additional qualification requirements will be explained and a time frame decided for re-qualification if needed. Contractors who are on hand will also attend this meeting.
6. The employee dealing directly with the contract company will determine the changes affecting the qualification of the individuals supplied by that company and will contact them with the changes. This will be done in person or by certified mail to ensure the contract company knows of the changes. The contract company will then send documentation to the company that they have supplied these changes to their affected personnel.
7. Personnel who do not qualify in the allotted time will go to a pending qualification file and will be supervised by qualified personnel according to the provisions in this manual until they meet the new qualification criteria.

Although the plan and evaluation tools will be updated as frequently as needed to accommodate changes to the pipeline system; management will review this plan annually to determine if there are any additional updates needed. During this review, it will also be determined if the evaluations have been effective in ensuring that the personnel performing the covered tasks are qualified. This review will also be used to assemble employee feedback on program effectiveness and needed improvements. These will be reviewed by management and incorporated as appropriate. Any concerns from this review will be handled immediately.

MANAGEMENT OF CHANGE

Overview

Communicate changes that affect covered tasks to individuals performing those covered tasks.

The Operator Qualification Program establishes responsibility for:

- Change of operating procedures;
- Update or modification to the Operator Qualification Program; and
- Communication of the substance and impact of change.

Change of Operating Procedures

Operating and maintenance personnel will attend various training classes and monitor various trade documentation to learn new and changing methods for pipeline inspection and maintenance. As new methods are being adopted, the operations and maintenance practices will be updated to reflect these standards. During the annual review of the operations and maintenance manual the respective covered task evaluation for operator qualification will be amended and a notice for personnel to be re-trained and evaluated on the new methods will be sent to all field supervisors.

Any changes to local operating procedures, hardware or protective devices will be documented by a Management of Change form as contained in HSE0004 and reviewed with the local operating personnel before the changes are implemented. Operational settings that remain within the Maximum and Minimum ranges as defined on the locations Protective & Control Device Drawing can be made without a Management of Change form being prepared, reviewed and executed.

Update or Modification to the Operator Qualification Program

The potential need to update or modify the Operator Qualification Program may be identified by an individual, supervisor, manager or vice president; however, this program establishes specific responsibility for monitoring with the intent of identifying changes that may impact the program or the performance of covered tasks. The Operations, Regulatory Manager has the responsibility to review and determine the appropriateness of proposed updates or modifications to the Operator Qualification Program. He will consult with subject matter experts and Management to make that determination. He will implement updates and modifications as appropriate and notify management of such.

Communication of Change

Management has the responsibility for notification of all individuals in regard to changes that may impact the performance of covered tasks. If these changes are significant they may require re-evaluation. If so, appropriate changes need to be written into the evaluations. The re-evaluations should be performed in a timely fashion. The Operations, Regulatory Manager has the responsibility to update the Operator Qualification Plan as part of the annual update to SGG's Procedural Manual for Operations, Maintenance, Risk Management and Emergency Response.

The SGG Supervisor in charge of overseeing Specialty Contractors must also ensure that these changes are communicate to them as appropriate.

Changes will be communicated using any of the following:

- Email
- Memo
- Meetings
- Certified Mail (Specialty Contractors)

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 8 - SGG's treatment of "Reevaluation Intervals" (Plan page 8 of 28, Revision date 07/15/04)		
Evidence	Obtained from	Identifying Witness
This exhibit shows that SGG provided instructions for establishing reevaluation intervals that were not followed, per Exhibit No. 7. In addition, the instructions provided were insufficient to establish realistic intervals for all covered tasks.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit

Evaluation Intervals

Each covered task has an evaluation interval that governs when an individual must be re-evaluated. A subject matter expert ("SME")in the designated discipline area determined the appropriate evaluation interval for each covered task. The duration of an interval must not exceed five years. SGG may, at its discretion, change the evaluation interval for any or all of the covered tasks at any time.

The following process was used to determine the re-evaluation frequencies for each covered task:

1. It was determined that there are three areas in which a task should be weighted. They are frequency, difficulty, and the consequence of performing the task incorrectly. Each was given the same amount of weight in the determination.
2. Numbers were assigned to evaluate each factor as follows:
   a. Frequency - More Frequently Than Annual = 1.5, Annual = 1, Less Frequent = 0.5
   b. Difficulty - Easy - 1.5, Moderate = 1, Very = 0.5
   c. Consequence of Performing Wrong - Little - 1.5, Moderate = 1, Very = 0.5
3. It was then determined which of these were appropriate for each factor for each task. Results were rounded to the next whole year.
4. When there is a certification involved in performing a task or part of a task, the interval of the certification will take precedence over the interval determined in this analysis.

U.S. Department of Transportation Office of Pipeline Safety Southwest Region		
EXHIBIT TAB		
Name of Operator: Enbridge Transportation Group South via Purchase of Shell Gas Gathering, LLC		
Exhibit No. 9 - "Appendix D" to SGG's OQ Plan (an Excel spreadsheet containing 3 pages, Revision date 07/28/04).		
Evidence	Obtained from	Identifying Witness
This exhibit shows that SGG provided instructions (in Exhibit 6) for establishing reevaluation intervals that were not followed. In addition, the intervals were established at an arbitrary 3 years for all covered tasks, rather than as established by the written procedure.	John Locantro, Regulatory Manager	Jason Terry, OPS SWR Greg Johnson, Texas Railroad Commission
Investigator Name: Bob Brown	Title: General Engineer	

Exhibit 9

Appendix D

Shell Gas Gathering accepts those qualification procedures listed below. For each task you may choose any one column (eWebOG, OQSG or NCCER Learning Series) to satisfy SGG Requirements. A blank space means that, even if available, the procedure is not accepted by SGG at this time.

"And" means that all tests or checklists within the box are required. "Or" means that either of the tests or checklists within the box is acceptable.

Third Party Qualification Method Mapping To SGG Operator Qualification Tasks

TASK #	TASK NAME	eWebOQ Module	OQSG Module	NCCER Learning Series	API/COOQ TasksList	Frequency (years)	Comments
1	Prevention of Accidental Ignition and Potential Ignition Sources	100				3	
2	Recognize and React to Abnormal Operating Conditions	101	All	67107	AOC	3	Each individual OQSG module contains Abnormal Operating Conditions
3	Emergency plans and Public and Contractor Education	102				3	
4	Excavation and Backfilling	106	CT19, CT20 and CT35	62107 and 62206	17, 18 and 39	3	all API/COOQ subtasks must be completed
5	Pigging Pipelines	107	CT41	62303	29	3	ditto
6	Leak Surveys and Leak Classification	200	CT16 and CT45	62201and 62206	15 and 52	3	ditto
7	Pipeline Patrol and Population Density Determination	201				3	
8	Odorization	202	CT52	67104 and 67105	57 and 58	3	
9	Inspect Buried Pipe when exposed	205	CT10	61105	5	3	all API/COOQ subtasksmust be completed
10	Leak Investigation	206				3	
11	Pipeline Failure Investigation	207				3	
12	Damage Prevention: Locating and Marking Pipeline facilities	300	CT15	62106	14	3	all API/COOQ subtasks must be completed
13	Valve Operator Maintenance	400	CT42 and CT23	63306, 63307, 63308, 64204, 64208 and 66102	19.5, 19.6, 19.7, 21.1, 21.4 and 21.5	3	
14	Valve Maintenance	401	CT42	63107, 66306, 66307 and 66308	19.1, 19.2, 19.3, 19.4 and 21.2 and 21.3	3	
15	Valve Inspection	402	CT22	62203	20	3	all API/COOQ subtasks must be completed
16	Inspecting and Testing Regulators, Relief valves and Control valves	402	CT24 and CT26	63205	23 and 24	3	
17	Pressure Testing Steel and Plastic Pipelines	403	CT37	62207	41	3	

TASK #	TASK NAME	eWebOQ Module	OQSG Module	NCCER Learning Series	API/COOQ TasksList	Frequency (years)	Comments
18	Pipeline Leak Repair	409	CT36	62304 and 62306	40.1, 40.2, 40.3, 40.4 and 40.5	3	
19	Pipeline Purging	411	CT48	67104 and 67105	50 and 51	3	
20	Hot Tapping and Stoppling	412	CT36	62304 and 62306	40.6, 40.7, 40.8, 40.9 and 40.91	3	
21	Up-rating Pipeline Systems	413	CT51	67104 and 67105	56	3	
22	Abandonment of Facilities	414	CT32	63209	36	3	
23	Installation of Anodes	415	CT08	61201	9	3	
24	Pipeline Shutdown and Start-up	416	CT39	67104 and 67105	43	3	
25	Installation of Steel Mains and Services	420				3	
26	Vault Inspection and Entry Procedures	421	CT46	62310	59	3	
27	Atmospheric Corrision	500	CT06	61106, 61206, 61207 and 61208	7.1	3	
28	Cathodic Protection Troubleshooting	501	CT08	61201, 61202, 61203 and 61204	4.1	3	
29	Cathodic Protection-Rectifier Inspection	502	CT03	61108	3	3	all API/COOQ subtasks must be completed
30	Protective Coatings	503	CT14	61106, 61107, 61207 and 61208	13	3	ditto
31	Installation of Test Stations	504	CT08	61109	2	3	ditto
32	Conduct Annual Cathodic Protection Survey	505	CT01	61108, 61203 and 61205	1.1, 1.2, 1.4 and 1.5	3	
33	Electrical Insulator Inspection and Testing Casings	506	CT01	61109	2	3	all API/COOQ subtasks must be completed
34	Internal Corrosion Monitoring	507	CT09 and CT12	61111	10	3	
35	Inspect Internal Pipe Surfaces	507	CT13	61110	12	3	ditto
36	Interference (AC and DC)	508	CT01	61203	1.3	3	
37	Pipe-to-Soil Surveys	509	CT01	61108	1.1	3	
38	Electric Arc Welding	600				3	
39	Welder Qualifications	601				3	
40	Weld Repairs and Weld Procedures	602	CT38	62308	42	3	all API/COOQ subtasks must be completed
41	Compressor Station Operations and Safety	700, 704, 705 and 706				3	
42	Compressor Station Operations-Reciprocating Units	701	CT58			3	
43	Compressor Station Operations-Turbine Units	703	CT57			3	
44	Inspecting and Testing of Relief Valves or devices at a Compressor Station	700	CT56			3	

TASK #	TASK NAME	eWebOQ Module	OQSG Module	NCCER Learning Series	API/COOQ TasksList	Frequency (years)	Comments
45	Inspecting and Testing of the Gas Detection System at a Compressor Station	700	CT54	64210	55	3	
46	Testing Emergency Shutdown Devices	402	CT50	67104 and 67105	54	3	
47	Inspection Activities for Tie-ins, Pipe replacements or other Components connecting to an existing pipeline		CT34	62205 and 62401	38	3	all API/COOQ subtasks must be completed
48	Subsea Pipeline Inspection		CT02U			3	
49	Gas Control	800, 900, 901 and 902				3	

Enbridge Offshore (Gas Gathering) L.L.C.
1100 Louisiana Suite 3300
Houston, Texas 77002

ENBRIDGE™

August 30, 2005

CERTIFIED MAIL (7004 1160 0007 3733 6529)
RETURN RECEIPT REQUESTED

Mr. Rodrick M. Seeley
Director, Southwest Region
Office of Pipeline safety
8701 South Gessner, Suite 1110
Houston, TX 77074

RECEIVED SEP 2005

Re: CPF No. 4-2005-2001M
Notice of Amendment

Mr. Seeley:

On October 10 and 11, 2004, the Office of Pipeline Safety ("OPS") and the Texas Railroad Commission ("TRC") conducted an onsite pipeline safety inspection of Shell Gas Gathering, LLC's ("SGG's") Operator Qualification Plan ("OQ") at their office in Houston. Subsequent to this inspection, Enbridge (U.S.), Inc, purchased SGG's assets on December 31, 2004. Enbridge Offshore (Gas Gathering) L.L.C. ("EOGG") is the successor to SGG.

The required amendments to SGG's OQ Plan as itemized in the OPS letter of August 18, 2005 will be incorporated into the new Enbridge Transportation South Operator Qualification Plan (to be transmitted under separate cover). Enbridge does not intend to contest the OPS findings nor request a hearing. However, with employees' efforts being consumed with recovery from the effects of Hurricane Katrina for the next several weeks, Enbridge requests an extension of 60 days for the submittal of these revised procedures to your office.

If you have any questions or require additional information, please call John Locantro at 713-353-5672.

Sincerely,

Richard Adams

Rich Adams
Vice President

cc: Scott Peterson
Garry Worone
Allan Schneider
Fred Whitted

U.S. Department
of Transportation
Pipeline and
Hazardous Materials Safety
Administration

8701 South Gessner, Suite 1110
Houston, TX 77074

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CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 8, 2005

Mr. Rich Adams
Vice President
Enbridge Offshore (Gas Gathering) L.L.C.
1100 Louisiana
Suite 3300
Houston, Texas 77002

RE: **Request for Time Extension - Response to Notice of Probable Violation (NOPV) Letter dated August 18, 2005 (Shell Gas Gathering)**

CPF No. 4-2005-2001M

Dear Mr. Adams:

Enbridge Energy Company, Inc. (Enbridge) submitted a Request for Time Extension dated August 30, 2005, regarding the referenced NOA, specifically, requesting an extension beyond the 30 day requirement.

We have reviewed your request for time extension and grant the extension of an additional 60 days (until November 1, 2005) in order to ensure that there is adequate time for review and written response of the items noted in CPF No. 4-2005-2001M.

If you have additional questions, please feel free to contact my office at 713-272-2859.

Sincerely,

R. M. Seeley
Director, Southwest Region

Enbridge Offshore (Gas Transmission) L.L.C.
1100 Louisiana, Suite 3300
Houston, TX 77002
www.enbridge-us.com

ENBRIDGE™

D

RECEIVED
OCT 31 2005
BY:

October 28, 2005

Mr. Rodrick M. Seeley
Director, Southwest Region
Office of Pipeline Safety
8701 South Gessner, Suite 1110
Houston, TX 77074

NOV 01 2005

RE: CPF No. 4-2005-2001M

Dear Mr. Seeley,

Subsequent to a pipeline safety inspection of Shell Gas Gathering, LLC [now known as Enbridge Offshore (Gas Transmission) L.L.C.] Operator Qualification (OQ) records and procedures conducted on October 10-11, 2004, Enbridge has received your Notice of Amendment (Notice) dated August 18, 2005. Enbridge appreciates the opportunity to respond to this evaluation and trusts that this input may assist in resolving any outstanding issues

Enbridge is dedicated to operator excellence and has a strong commitment to ensuring the safety of the public and the protection of the environment. In response to the specific items in the Notice the following is offered:

Item No. 1
192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a.) Identify covered tasks;

A. The Plan "Overview" section defines "operations and maintenance tasks" (part 2 of the 4-part test) so only those items defined in subparts I, L & M of Part 192 may be considered. The rule's preamble was very clear about O & M tasks being dependent on other subparts of the code for performance criteria. The "Glossary of Terms" contains other definitions which indicate some tasks may have been erroneously excluded from the covered task list. Definitions provided in the regulations must be preserved as written, and not modified by an operator. OPS has posted acceptable definitions at http://primis.rspa.dot.gov/oq/index.htm (in the OQ Home website's Glossary). The problematic definitions contained in the OQ Plan are:

- **"Covered Task"**
- **"Four Part Test"**
- **"Operations and Maintenance Tasks"**
- **"Performed on a Pipeline Facility"**
- **"Task Performed on a Pipeline Facility"**

Response: The terms noted above have been defined in Exhibit G: Glossary of Terms and Acronyms of the revised Enbridge Operator Qualification (OQ) Manual. The specific definitions from the OQ Manual are enclosed as Attachment 1.

B. SGG indicated to the inspection team that Task #27, Atmospheric Corrosion, did not in fact cover "painting" an above-ground pipeline to protect it from atmospheric corrosion, clearly a covered task.

Response: This covered task is now listed as Task No. 7 in Exhibit A: Covered Task List of the revised OQ Manual. The specific details of this task as taken from the OQ Manual are enclosed as Attachment 2.

C. There is no "Small pipe, fittings and tubing" task, which ensures individuals recognize these small items on high pressure pipelines can present extreme hazards if one is not competent to install, maintain, operate and/or replace them and are aware of the AOCs involved.

Response: This item will be addressed as part of an upcoming modification to the OQ Manual. The modification will include the addition of the following task to Section 13.1 – Exhibit A: Covered Task List:

Task Name: Small Piping/Tubing Repair/Replacement
Description: This task consists of the activities related to the installation, maintenance, operation, and replacement of small piping or tubing that is under high pressure.
Re-Evaluation Frequency: 4
Span-of-Control: 2
Re-Evaluation Method: Performance Evaluation

The modification will also include the addition of the above noted task to Section 13.5 – Exhibit E: Re-Evaluation Frequencies:

Title: Small Piping/Tubing Repair/Replacement
Frequency: 1.5
Difficulty: 1.5
Consequences: 1
Interval: 4

This modification will be distributed to all OQ manual holders as part of the next scheduled revision.

D. The OQ Plan should include language clearly indicating that covered tasks, whether performed in normal, abnormal or emergency situations, should be performed by qualified individual, or by others who are directed and observed by a qualified individual.

Response: This item is addressed in Section 2.5 – Emergency Response in the revised OQ Manual. Section 2.5 from the OQ Manual is enclosed as Attachment 3.

Item No. 2
192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(b.) Ensure through evaluation individuals performing covered tasks are qualified;

Re: 192.803 Definitions

***Evaluation* means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:**

...[list of permissible methods omitted]

***Qualified* means that an individual has been evaluated and can:**
a) Perform assigned covered tasks; and
b) Recognize and react to abnormal operating conditions.

A. The inspection revealed all employee evaluations currently assess only the knowledge component of the complete knowledge, skills and ability (KSA) "package" that demonstrates an individual can in fact perform those assigned covered tasks which may be physically and/or mentally challenging or have severe consequences if performed improperly.

Response: This item is addressed in Section 6.2 – Ongoing Evaluation in the revised OQ Manual. Section 6.2 from the OQ Manual is enclosed as Attachment 4.
B. The plan does not address a "cooling off" period between failing a knowledge test and being allowed to retake the test.

Response: This item is addressed in Section 3.4 – Unsuccessful Qualification Action Steps in the revised OQ Manual. Section 3.4 from the OQ Manual is enclosed as Attachment 5.

C. The various computer based training modules (CBTs) used for employee training and evaluations were developed by an independent vendor and may not reflect the procedures contained in SGG's own Operations, Maintenance and Emergency Response manual. The Plan should provide assurance there is a valid relationship between the evaluations conducted under this system and the procedures actually followed by the employees.

Response: This item is addressed in a correction to the OQ Manual. The correction includes the addition of the following language to the second paragraph of Section 7.0 – Operator Qualification Program Maintenance: "*This review will include employee input on how the third party training and evaluations follow the procedures used in the field. Additional training and evaluation will be provided as necessary to ensure personnel are qualified to perform the Enbridge written procedures.*"

D. The plan does not specifically discuss the use of "certificated" contractors or how they are to be qualified. Such individuals must present a certificate indicating their current competence to perform specialized work. In order to become "qualified, these individuals must also be evaluated on the AOCs the operator has defined as those which may be encountered during performance of the covered task.

Response: This item is addressed in Section 9.0 – Contractor Qualifications in the revised OQ Manual. Section 9.0 from the OQ Manual is enclosed as Attachment 6.

Item No. 3
192.805 Qualification program.

> **(c.). Allow individuals not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;**

A. SGG'S OQ Plan fails to provide any meaningful guidance to qualified individuals concerning to the number of non-qualified individuals they may "direct and observe" to accomplish a covered task. The ratio of qualified to non-qualified individuals is referred to as "span of control".

Response: This item is addressed in Section 4.0 – Non-Qualified Individuals and in Section 13.1 – Exhibit A: Covered Task List (Span of Control) in the revised OQ Manual. Section 4.0 and page 1 of Exhibit A from the OQ Manual are enclosed as Attachment 7.

B. SGG's OQ Plan does not explain its use of various forms of the term "supervise", leaving that term open to individual interpretation. "Direct and observe" is the preferred term.

Response: This item is addressed in Section 4.0 – Non-Qualified Individuals in the revised OQ Manual enclosed as part of Attachment 7.

C. SGG's OQ Plan provided a list of tasks that a non-qualified "should" not perform, even if directed and observed by a qualified individual. The tasks listed are those which require specialized knowledge, training skills and abilities and are appropriate to this category. However, the language should be strengthened (non-qualified individuals "must" not perform the tasks listed).

Response: This item is addressed in Section 4.0 – Non-Qualified Individuals and in Section 13.1 – Exhibit A: Covered Task List in the revised OQ Manual. Both of these sections are enclosed as Attachment 7.

Item No. 4
192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

> **(f.) Communicate changes which affect covered tasks to individuals performing those covered tasks;**

A. SGG's OQ Plan currently addresses this topic over two sections, "Program Maintenance" and "Management of Change" (MOC). Those aspects addressing ordinary OQ program updates and modifications (e.g., changes that have no impact on the performance of covered tasks) should be addressed within the Program Maintenance section and plans for communicating those types of changes described therein. Changes fitting the criteria of paragraph (f) above (those affecting covered tasks) should be addressed within the MOC section. These changes should be categorized by their relative significance, which in turn should dictate how and when the changes are to be communicated to affected individuals.

Response: This item is addressed in Section 8.0 – Management of Change in the revised OQ Manual. Section 8.0 from the OQ Manual is enclosed as Attachment 8.

B. The OQ Rule does not provide for a "grace" period during which non-qualified individuals may be evaluated on a covered task they are already

performing without benefit of being directed and observed by a qualified individual. The MOC section of ETGS's OQ Plan must be integrated with the overall company's MOC process so coordination between Engineering, Operations, Maintenance and Regulatory departments may result in planning for required evaluations to produce qualified individuals in advance of the need.

Response: This item is addressed in Section 8.0 – Management of Change in the revised OQ Manual. Section 8.0 from the OQ Manual is enclosed as Attachment 8.

Item 5
192.805 Qualification program.

> **(g.) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.**

A. The "Evaluation Intervals" portion of the SGG Plan describes a typical "difficulty, importance, and frequency" (DIF) analysis approach to assigning subsequent evaluation frequency, with rounding to the next highest whole number of years (limited to a maximum of 5 years). Additionally, the inspection revealed that SGG's intent was to evaluate individuals of infrequently performed tasks just prior to performance. However, an inspection of Appendix D (which maps the acceptable qualifications methods to SGG'S covered to SGG's covered task list) reveals that all covered tasks were assigned an arbitrary 3-year interval.

Response: This item is addressed in Section 3.8 – Evaluation Intervals, Section 13.1 – Exhibit A: Covered Task List, and Section 13.5 – Exhibit E: Re-Evaluation Frequencies in the revised OQ Manual. Section 3.8 is enclosed as Attachment 9, page one of Exhibit A is enclosed as part of Attachment 7, and page one of Section 13.5 is enclosed as Attachment 10

B. The covered task list must be modified to reflect which infrequently performed tasks will only require evaluations prior to performance. The remaining task (including those that may be added as a result of Item #1 above) should indicate a reevaluation interval supported by the rewritten "Evaluation Process" section of the Plan, which must reflect the actual intent of the new operator (ETGS).

Response: This item is addressed in Section 13.1 – Exhibit A: Covered Task List (Re-Evaluation Frequency). Task #29 from Exhibit A reflects the manner in which this item is addressed throughout the OQ Manual and is enclosed as Attachment 11.
Enbridge continually seeks to further develop and maintain strong, quality partnerships with the Office of Pipeline Safety in assuring full compliance with all

regulations through open and ongoing communications. Enbridge is dedicated to operator excellence and is strongly committed to operating a safe and reliable pipeline system while protecting the public, our employees, and the environment.

If you have any questions, please do not hesitate to contact me. Thank you once again for the opportunity to respond to the noted issues.

Sincerely,

Scott R. Peterson

Scott Peterson
Manager, Compliance and Systems Integrity
Enbridge Energy Company, Inc.
(713) 821-2176

Enclosures (11)

cc: Doug Krenz (w/o enclosures)
Garry Worone (w/o enclosures)
Rich Adams (w/o enclosures)

COVERED TASK - An activity by an individual or a group of individuals that (a) is performed on a pipeline facility and; (b) is an operations and maintenance task and; (c) is required by 49 CFR Part 192 or 195; and (d) effects the operation or integrity of the pipeline.

ATTACHMENT 1

FOUR PART TEST - A test that is applied to any task to determine if it meets the requirements of a "covered task" for the purposes of this program. A task must meet ALL FOUR of these conditions to be considered a covered task. The four parts of the test are:

1. Is the task performed on a pipeline facility,
2. Is the task associated with operations or maintenance,
3. Is the task required by Part 192 or 195, and
4. Does the task affect the operation or integrity of the pipeline?

OPERATIONS AND MAINTENANCE TASKS - Activities done by an individual or group of individuals (a) to perform a function on a pipeline facility; or (b) to upkeep of a pipeline facility.

1. A "New construction task" changes to an operations and maintenance task when the pipeline facility is being commissioned or during the act of connecting to an active pipeline facility.
2. Emergency response activities are not Operations and Maintenance task.
3. Activities on pipelines that have never been in service or pipelines that are isolated or physically not connected to a source of hazardous liquid or fabrication of new installations are not Operation and Maintenance task.

PERFORMED ON A PIPELINE FACILITY - An activity that is performed by an individual or group of individuals whose performance directly impacts the pipeline facility.

1. **Pipeline Facility** is new and existing pipe, right of ways and any equipment, facility or building used in the transportation of a hazardous liquid or gas.
2. **Activity** means physical, visual, or mental effort directed at achieving a results.
3. **Removed from the system** means that part of the pipeline system is physically removed or isolated from the pipeline system.
4. **Pipeline System** means all parts of a pipeline facility through which a hazardous liquid moves in transportation (line pipe, valves, appurtenances, pumps, meters, tanks, etc.)

Task No.	Name	Description	Re-Evaluation Frequency	Span-of-Control	Re-Evaluation Method	
					Enbridge Employee	Contractor[2]
7	Prevention of Atmospheric Corrosion	Each component in the pipe system that is exposed to the atmosphere must be cleaned and coated with a suitable material to prevent atmospheric corrosion, and this protection must be maintained.	3	3	EWebOQ 100ACCIG, 101ABNOR, 500ATMO, 510 ATMPO, LQ100 Performance Evaluation	OQSG CT06 Performance Evaluation NCCER 61106, 61207, 61208, 61206, & 67107 NCCER Performance Evaluations PV071, PV072, PV073, PV074, PV075, PV076, & PV077
					NACE Certification	NACE Certification EWebOQ 100ACCIG, 101ABNOR, 500ATMO, 510 ATMPO, LQ100

ATTACHMENT 2

2.5 - Emergency Response

All activities that occur during an emergency that would be considered a normal operations or maintenance task if it were not for the emergency will be performed by a qualified individual. This includes opening / closing valves, resetting alarms, blowdown, shutdown, etc.

6.2 - Ongoing Evaluation

Enbridge Management MAY use any combination of the following to periodically check individual performance to determine that covered tasks are being performed properly:

- Internal audits,
- Third party audits or inspections,
- Assessments,
- Employee review or feedback,
- Technical specialist review, and
- On-the-job spot checks.

The local Enbridge Operations Superintendent or Operations Supervisor will use good judgment to determine if an individual requires re-evaluation of his ability to adequately perform a covered task. Management, at its discretion, may suspend an individual's qualification if there is reason to believe that an individual is no longer qualified to perform the covered task.

Reasons for such action include, but are not limited to:

- Inability to perform the essential functions of the covered task with or without reasonable accommodation, (including physical or mental disability)
- Unsatisfactory performance,
- Violation of Enbridge Drug and Alcohol Policy,
- Individual's request not to perform the covered task, or
- Excessive time has elapsed since the individual last performed the task.

3.4 - Unsuccessful Qualification Action Steps

If the initial evaluation process for a specific covered task results in an unsuccessful evaluation status, the individual may be evaluated again after 24 hours. If the second evaluation process results in an unsuccessful evaluation, another evaluation will be administered in the following manner:

1. The Operations Manager will notify the individual's direct supervisor that the individual's evaluation for a specific covered task has been unsuccessful.
2. The supervisor will conduct one-on-one training with the individual regarding the specific requirements of the covered task. This training may involve both classroom and field instruction.
3. When the supervisor is satisfied that the individual has mastered the specific covered task, he will allow the individual to attempt qualification again.

9.0 - Contractor Qualifications

Enbridge utilizes contractors that are qualified under this plan and also contractors who provide their own qualifications as accepted under this plan.

It is the responsibility of the Contractor to provide qualified, competent workers under the terms of its specific contract with Enbridge. Enbridge has reviewed the evaluation methods and criteria used by the following named consortiums and has found them to be compatible with the qualification standards set by Enbridge. A Contractor must qualify its employees through either the National Center for Construction, Education and Research ("NCCER"), eWebOQ or the Operator Qualifications Solutions Group ("OQSG") and insure that all of the Specialty Contractor employees who perform covered tasks on behalf of Enbridge are qualified to perform those tasks or will be directly supervised by someone who is qualified to perform those covered tasks.

Contractors must subscribe to ISNetworld. The Contractor must provide qualification information to ISNetworld prior to working for Enbridge. This will allow Enbridge to check contractor qualifications online.

Upon review of the information provided by the Contractor (via ISNetworld), Enbridge Management will designate as qualified under its Operator Qualification program those Contractor employees that it deems acceptable. This designation lasts for the duration of the contract or until that individual's evaluation date expires.

Prior to a Contractor beginning work on the pipeline or pipeline facility, an Enbridge representative will ensure that the individual knows how to recognize and respond to any AOCs that may happen at this facility. This will be done at least once each evaluation period for ongoing jobs or for Contractors that regularly perform the covered task at the facility. This will be documented using the form in *Exhibit F: Specialty Contractor Form* or its equivalent.

4.0 - Non-Qualified Individuals

Enbridge will allow individuals that are not qualified pursuant to the evaluation process to perform a covered task if directed and observed by an individual that is qualified.

Enbridge will in some cases utilize non-qualified personnel to perform covered tasks. This will be acceptable, as defined in 192.805(c) and 195.505(c), only while under the direction and observation of an individual who possesses a current qualification for the designated covered task (i.e. Qualified Individual). The Qualified Individual must be able to direct the actions of the individual performing the covered task and must be able to take immediate corrective action, if necessary. The Qualified individual must be able to communicate with the non-qualified individual even if he speaks and comprehends a language other than English. The number of non-qualified individuals that can be directly supervised by a qualified individual is dependent on the severity of the task and the existence of limiting environmental conditions. The maximum number of non-qualified individuals that a Qualified Individual may supervise is listed in *Exhibit A: Covered Task List* (Span-of-Control) of this manual. This number may be reduced on a case-by-case basis if circumstances warrant. Examples of these conditions are: line of sight obstructions, rain, fog, loss of daylight, etc.

The above also applies to an individual who is working on their initial qualification; those who have had their qualification suspended due to an accident or for cause or have allowed the re-evaluation interval to lapse.

Exhibit A: Covered Task List shows tasks that may not be performed by a non-qualified individual (i.e. Span-of-Control = 0).

13.0 - Appendices

13.1 - Exhibit A: Covered Task List

(Evaluation Frequency, Span-of-Control & Method of Evaluation)

Task No.	Name	Description	Re-Evaluation Frequency	Span-of -Control	Re-Evaluation Method: Enbridge Employee	Re-Evaluation Method: Contractor[2]
1	Conduct Annual Surveys	Annual surveys are conducted each calendar year for each operator's pipeline system that is under cathodic protection to ensure that the protection is adequate. This task is related to the collection of data and does not include analysis. This task includes: close interval survey, measurement of pipe-to-soil potentials, measurement of casing-to-soil potentials, testing to detect interference and/or to ensure electrical isolation from foreign structures, inspection and electrical test of bonds, and measurement of tank bottom-to-soil potentials.	4	2	EWebOQ 100ACCIG, 101ABNOR, 509PSSUR, 506INSUL, LQ100 & LQ416 Performance Evaluation	OQSG CT01 Performance Evaluation
						NCCER 61108, 61205, 61203, 67107 & Performance Evaluations PV011, PV012, PV013, PV014, PV015
					NACE Certification	EWebOQ 100ACCIG, 101ABNOR, 509PSSUR, 506INSUL, LQ100 & LQ416
						NACE Certification

[2] The contractor may use any of the third party evaluation methods listed in this column. However, if more than one module is listed for a particular company, then all of those must be taken. For example, all of the NCCER modules and Performance Evaluations must be completed to be considered qualified. Also, a person with an industry certification must have documentation of AOCs according to that section of the plan.

8.0 - Management Of Change

As operations and maintenance practices change, the respective covered task evaluation for operator qualification will be amended as appropriate. Should these changes impact training, evaluation methods or frequencies, this will be communicated to all affected personnel.

During annual program reviews or whenever there is a change such as described above that may affect this program, the following will be done:

1. The program will be evaluated to determine the effect.
2. Work procedures will be modified or created as necessary.
3. Evaluation tools will be modified or created as necessary.
4. The written plan, including the covered task list, will be modified as necessary.
5. Personnel will be informed of these changes as described below:

   Minor Change - These changes require informal communication such as a memo or an email. These may include, but are not limited to: procedure number changes, task number changes, equipment name changes, etc.

   Middle Change - These changes require a more formal method of communication such as an informal meeting or an email requiring a response. An example of these changes is procedure changed to modify steps. The updated procedure should be distributed at this time.

   Major Change - These changes require a meeting with all individuals that perform the covered task and may include a training session. Examples of this type of change are discovery of a new task or a procedure being re-written or substantially updated. Changed procedures will be handed out at this time. Additional qualification requirements will be explained and a time frame decided for re-evaluation if needed. The re-evaluation must be performed prior to the change taking affect. Contractors who are on hand will also attend this meeting. This meeting will be documented.
6. For contractors impacted by this change, the employee dealing directly with the contract company will determine the changes affecting the qualification of the individuals supplied by that company and will contact them with the changes. This will be done in person or by certified mail or ISNetworld to ensure the contract company knows of the changes. The contract company will then send documentation to Enbridge that they have supplied these changes to their affected personnel.
7. Personnel who do not qualify in the allotted time will no longer be considered qualified and will be supervised by a qualified individual according to the provisions in this manual until they meet the new qualification criteria.

3.8 - Evaluation Intervals

Each covered task has a corresponding evaluation interval that governs when a qualified individual must be re-evaluated. *Exhibit E: Re-evaluation Frequencies* identifies the re-evaluation intervals for each covered task.

The following process was used to determine the re-evaluation intervals for each covered task:

1. It was determined that there are three areas in which a task should be weighted. They are frequency, difficulty, and the consequence of performing the task incorrectly. Each was given the same amount of weight in the determination.

   Numbers were assigned to evaluate each factor as follows:

   (a) Frequency

More Frequently Than Annual = 1.5

Annual = 1

Less Frequent = 0.5

Difficulty

Easy = 1.5

Moderate = 1

Very = 0.5

Consequence of Performing Wrong

Little = 1.5

Moderate = 1

Strong = 0.5

2. All three factors were summed to produce the re-evaluation interval. Tasks that are performed less frequently than the re-evaluation interval listed in *Exhibit E: Re-evaluation Frequencies* may be re-evaluated prior to the next time the task is to be completed, even if that falls outside of the re-evaluation interval prescribed in *Exhibit E: Re-evaluation Frequencies.*

3. When there is a certification involved in performing a task or part of a task, the interval of the certification will take precedence over the interval determined in this analysis. Aside from the technical expertise expected of individuals possessing such certifications, Enbridge will verify that such individuals have been fully qualified as required, and that AOC evaluation has been included in their qualifications.

4. Welders must maintain their qualifications by following requirements in 49 CFR 195.222 and/or 49 CFR 192.227. In addition to these qualification requirements, AOC training will take place at the intervals prescribed in *Exhibit E: Re-evaluation Frequencies* for welding tasks.

ATTACHMENT 10

13.5 - Exhibit E: Re-evaluation Frequencies

Task No.	Title	Frequency	Difficulty	Consequence	Interval[4]	Comment
1	Conduct Cathodic Protection System Surveys	1	1.5	1.5	4	
2	Install and Maintain Cathodic Protection Test Leads	1	1.5	1.5	4	
3	Inspect Rectifiers	1.5	1.5	1	4	
4	Maintain Rectifier	1	0.5	0.5	2	
5	Inspect Buried Pipe When Exposed	1	1	0.5	2.5	
6	Electrically Inspect Bare Pipe	0.5	1	0.5	2	
7	Prevention of Atmospheric Corrosion	1	1	0.5	2.5	
8	Measure Wall Thickness	1	1	0.5	2.5	
9	Remediate External Corrosion	1	0.5	1	2.5	
10	Monitor Internal Corrosion	1	1	1	3	
11	Remediate Internal Corrosion	1	0.5	1	2.5	
12	Inspect Internal Pipe Surface	0.5	1	0.5	2	
13	Application and Repair of External Coating	0.5	1.5	1.5	3.5	
14	Place and Maintain Line Markers	1.5	1.5	1	4	
15	Inspect Surface Conditions of Right-of- Way	1.5	1.5	1.5	4.5	
16	Inspect Navigable Waterway Crossings	0.5	1.5	1.5	3.5	This is only required every 5 years. The evaluation will be performed prior to the task or every 2 years, whichever is longer.
17	Provide Temporary Marking of Buried Pipelines Prior to Excavation	1.5	1.5	0.5	3.5	

[4] This interval is rounded up to the nearest whole number for re-evaluation.

Task No.	Name	Description	Re-Evaluation Frequency	Span-of-Control	Re-Evaluation Method	
					Enbridge Employee	Contractor[2]
29	Protect Breakout Tanks from Static Electricity, Lightning, and Stray Electrical Currents	This task consists of the activities necessary to protect breakout tanks from the hazards of static electricity, lightning, and stray electrical currents.	This task is not performed on a routine basis. Individuals will be qualified prior to conducting task or every 2 years whichever is greater	0	Written Exam Performance Evaluation	NCCER 62303
					API Certified	API Certified

ATTACHMENT 11

U.S. Department
of Transportation

Pipeline and
Hazardous Materials
Safety Administration

8701 S. Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 24, 2006

Mr. Rich Adams
Vice President, Operations & Engineering
Enbridge Energy Company, Inc.
1100 Louisiana
Suite 3300
Houston, Texas 77002

CPF No. 4-2005-2001M

Dear Mr. Adams:

On October 10 and 11, 2004, representatives from the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Texas Railroad Commission, pursuant to chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of the Shell Gas Gathering, LLC (SGG) Operator Qualification plan, procedures, and records in Houston, Texas. As a result of the inspection, SGG was issued a Notice of Amendment on August 18, 2005. This Notice proposed amendment of your procedures to assure safe operation of your pipeline facility.

SGG submitted its amended procedures on October 28, 2005. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

U.S. Department
of Transportation

Pipeline and
Hazardous Materials
Safety Administration

Central Region
Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

WARNING LETTER
AND
NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 19, 2005

Mr. Dan Tutcher
President
Enbridge Energy L.P.
1100 Louisiana Suite 2950
Houston, Texas 77002

CPF No. 3-2005-5021

Dear Mr. Tutcher:

On May 20, 2004, a representative of the Minnesota Office of Pipeline Safety (MN-OPS) acting as an Interstate Agent for the Office of Pipeline Safety (OPS), received notification of a crude oil leak at an above-ground break-out tank in the Clearbrook Terminal. Pursuant to Chapter 601 of 49 United States Code, an investigation of the incident was initiated.

As a result of the investigation, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

   a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

   c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

   (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

The investigation revealed that Enbridge Energy L.P.'s (Enbridge) Operation and Maintenance Manual (O&M) was deficient in providing guidance needed when conducting the required inspections of the above-ground storage tanks (AST). Specifically, there was no guidance in determining what items pertaining to the AST's were to be inspected including tank foundations, dikes, appurtenances, and invasive plant and animal actions. The procedure also did not indicate when the inspections needed to occur, or how the pertinent information would be directed to the appropriate personnel so that corrective actions to correct any deficiencies noted would be done.

The evidence, as presented during the investigation, clearly shows there were cavities under and around the "D" door that allowed flexion of the fiberglass liner and the floor plates, which contributed significantly to the release. Interviews revealed that there had been an ongoing problem (since 1998) with burrowing animals in the tank yard. Your personnel stated that they addressed the problem by eliminating the animals. However, no additional procedures were written to require continuing surveillance for burrowing animals or anything that could undermine the integrity of the tank bottom. Additionally, there were no procedures written for corrective action, should those conditions be found.

2. **§195.432 Breakout tanks.**

§195.432(b) requires that each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).

§195.432(d) requires that the intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.

Enbridge did not begin the monthly in-service inspection of the breakout tanks in the Clearbrook Terminal until January of 2002. The inspections should have begun on May 3, 1999.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persist up to a maximum of $1,000,000 for any series of violations. The Compliance Officer has reviewed the circumstances and supporting documents involved in item 2 and has decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

With regard to item 1, this Notice of Amendment serves as your notification that this office considers your procedures/plans inadequate. Under 49 C.F.R. §190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or a request for a hearing within 30 days after receipt of this Notice. If you do not wish to contest this Notice of Amendment, you may provide your revised procedures within 90 days of receipt of this notice. After reviewing the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 C.F.R. §190.237.

Please refer to CPF No. 3-2005-5021 in any correspondence on this matter.

Sincerely,

Ivan A. Huntoon
Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

Enclosure

cc: Charles Kenow - MNOPS

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ENBRIDG

RECEIVED

06/17/05

June 16, 2005

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2005-5021

Dear Mr. Huntoon:

In response to the Warning Letter and Notice of Amendment we received dated May 19, 2005, stemming from a crude oil leak in an above-ground breakout tank, we offer the following:

1A. The investigation revealed that Enbridge Energy L.P.'s (Enbridge) Operation and Maintenance Manual (O&M) was deficient in providing guidance needed when conducting the required inspections of the above-ground storage tanks (AST). Specifically, there was no guidance in determining what items pertaining to the AST's were to be inspected including tank foundations, dikes, appurtenances, and invasive plant and animal actions.

Response:
Tank Inspections are addressed in the Enbridge Operating and Maintenance Manual Book 3: Pipeline Facilities, Subject Number 09-02-02. Guidance on items pertaining to AST's that are to be inspected can be found under the "Routine Inspections" heading as follows:

"Visually inspect the exterior of aboveground storage tanks monthly for:

- *Evidence of leaks (e.g., on shell, flanges, mixers)*
- *Changing conditions (e.g., shell distortions, settlement or heaving, active corrosion)*
- *Condition of the foundation, paint coatings, floating roof, insulation systems, and appurtenances*

NOTE: For more information, see the Routine In-Service Tank Inspection Report in the Tank Management database, or the applicable Maximo Job Plan."

The Maximo Job Plan for routine monthly tank inspections lists the following inspection points:

- *Check for leaks on shell, flanges, mixers or other.*
- *Check for new signs of shell distortions, settlement or heaving, active corrosion, oil or water in tank lot / pad or on roof.*
- *Check the foundation for conditions of excessive spelling, cracking, wash-out, rotting animal nesting, etc.*
- *Check the paint for fading, flaking, peeling, scratched, gouged, etc.*
- *Check the floating roof for paint condition, buckling, rolling ladder, secondary seal, foam dam, etc.*

- *Other – Check the insulation, mixers, stairs, other appurtenances, fire protection piping, etc.*

The routine in-service monthly tank inspection report lists the applicable O&MP and API 653 references as well as the following inspection points:

- *Check for leaks on shell, flanges, mixers or other*
- *Check for new signs of shell distortions, settlement or heaving, active corrosion, oil or water in tank lot/pad or on roof*
- *Foundation (excessive spelling, cracking, wash-out, rotting, animal nesting, etc.)*
- *Paint (fading, flaking, peeling, scratched, gouged, etc.)*
- *Floating Roof (paint condition, buckling, rolling ladder, secondary seal, foam dam, etc.)*
- *Other: (insulation, mixers, stairs, other appurtenances, fire protection piping, etc.)*

Enbridge believes that these procedures adequately define the scope of the routine inspections and meet the current DOT requirements.

1B. The procedure also did not indicate when the inspections needed to occur, or how the pertinent information would be directed to the appropriate personnel so that corrective actions to correct any deficiencies noted would be done.

Response:
Book 3: Pipeline Facilities, Subject Number 09-02-02, Table 1, Summary of Atmospheric Tank Inspections, details the type, frequency, and appropriate employee (either company or contract) responsible for completing Routine In-Service, Annual In-Service, Formal In-Service, and Formal Out-of-Service inspections. For Routine In-Service inspections, the table states that the frequency is monthly, and the inspection is performed by an employee *"knowledgeable in tank farm operations, specifics of the tank, and characteristics of the product stored; or, for field tanks, competent person in accordance with API 12R1, Appendix A.2".*

Book 3: Pipeline Facilities, Subject Number 09-02-02, describes how information would be directed to the appropriate personnel for corrective action. The following is written in the Responsibilities section under Corrective Action:

"Site supervisors are responsible for reviewing routine and annual atmospheric tank inspection reports, and for:
- *Evaluating the need for repairs*
- *Initiating and monitoring repairs*
- *Consulting with the regional engineer, contract inspector, and Operations Services for unusual or major repairs*
- *Ensuring completed repairs are documented*

NOTE: Major repairs include re-leveling a tank, welding within the floor-to-shell critical zone, or any work requiring a hydrotest."

Enbridge feels that the existing procedures adequately define the inspection intervals and timelines, as well as responsibilities associated with the inspection and review of the results. However, Enbridge does acknowledge that at the time of the OPS investigation, a gap did exist in the documentation of corrective action to deficiencies noted during the routine inspections. To enhance the ability to track the progress of the remediation of the deficiencies noted, Enbridge has modified both the Routine and Annual In-Service Tank Inspection Forms to include a Maximo Work Order tracking number for each deficiency requiring corrective action. The remediation activities and follow-up documentation will be tracked in Maximo until the deficiencies are resolved. In addition, the Routine and Annual In-Service Tank Inspection Forms include a review and sign off by the Site Supervisor who is responsible to monitor and record completion of action items identified by the Inspector.

1C. The evidence, as presented during the investigation, clearly shows there were cavities under and around the "D" door that allowed flexion of the fiberglass liner and the floor plates, which contributed significantly to the release. Interviews revealed that there had been an ongoing problem (since 1998) with burrowing animals in the tank yard. Your personnel stated that they addressed the problem by eliminating the animals. However, no additional procedures were written to require continuing surveillance for burrowing animals or anything that could undermine the integrity of the tank bottom. Additionally, there were no procedures written for corrective action, should those conditions be found.

Response:
Enbridge believes that our existing procedures are adequate to address the issue of burrowing animals and that no modification is necessary. Animal nesting is specifically listed on the Routine In-Service Tank Inspection Form, and "Cavities under foundation" is listed in the Maximo Job Plan. The procedures for corrective action are listed in the response to item1B.

2. Enbridge did not begin the monthly in-service inspection of the breakout tanks in the Clearbrook Terminal until January of 2002. The inspections should have begun on May 3, 1999.

Response:
Enbridge had a formal In-Service inspection process in place prior to the May 3, 1999 date specified in §195.432(d). Routine In-Service inspections were completed on a weekly basis in conjunction with tank level gauging. Inspection results were documented on the tank gauging forms and were logged through the tank gauging spreadsheets. In 2002, Enbridge implemented a more formal documentation process. Inspections are now completed monthly and are documented through the Routine In-Service Tank Inspection Report. Enbridge maintains the Routine In-Service Tank Inspection Reports for a minimum of two years.

We trust that the above information sufficiently addresses the concerns noted in your May 19, 2005 letter. Should you have any further questions or concerns, please contact me.

Sincerely,

Mark Willoughby

c: Art Meyer
Steve Irving
Mark Sitek
Charles Kenow - MNOPS

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

November 3, 2006

Mr. Terry McGill
President
Enbridge Energy, L.P.
1100 Louisiana, Suite 3300
Houston, Texas 77002

CPF No. 3-2005-5021

Dear Mr. McGill:

On May 20, 2004, a representative of the Minnesota Office of Pipeline Safety (MN-OPS) acting as an Interstate Agent for the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of Enbridge Energy, L.P. at the Clearbrook, Minnesota, Terminal where a leak had occurred. As a result of the investigation, Enbridge Energy, L.P. was issued a Warning Letter and Notice of Amendment on May 19, 2005. This Notice proposed amendment of your Operations and Maintenance Manual to assure safe operation of your pipeline facility.

Enbridge submitted a response letter on June 16, 2005. My staff has reviewed the response and it appears that all of the inadequacies outlined were shown to be addressed in your existing procedures. Also the gap in documentation of corrective action has been addressed satisfactorily.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

Donald E. Moore

for Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

- *Other – Check the insulation, mixers, stairs, other appurtenances, fire protection piping, etc.*

The routine in-service monthly tank inspection report lists the applicable O&MP and API 653 references as well as the following inspection points:

- *Check for leaks on shell, flanges, mixers or other*
- *Check for new signs of shell distortions, settlement or heaving, active corrosion, oil or water in tank lot/pad or on roof*
- *Foundation (excessive spelling, cracking, wash-out, rotting, animal nesting, etc.)*
- *Paint (fading, flaking, peeling, scratched, gouged, etc.)*
- *Floating Roof (paint condition, buckling, rolling ladder, secondary seal, foam dam, etc.)*
- *Other: (insulation, mixers, stairs, other appurtenances, fire protection piping, etc.)*

Enbridge believes that these procedures adequately define the scope of the routine inspections and meet the current DOT requirements.

1B. The procedure also did not indicate when the inspections needed to occur, or how the pertinent information would be directed to the appropriate personnel so that corrective actions to correct any deficiencies noted would be done.

Response:
Book 3: Pipeline Facilities, Subject Number 09-02-02, Table 1, Summary of Atmospheric Tank Inspections, details the type, frequency, and appropriate employee (either company or contract) responsible for completing Routine In-Service, Annual In-Service, Formal In-Service, and Formal Out-of-Service inspections. For Routine In-Service inspections, the table states that the frequency is monthly, and the inspection is performed by an employee *"knowledgeable in tank farm operations, specifics of the tank, and characteristics of the product stored; or, for field tanks, competent person in accordance with API 12R1, Appendix A.2".*

Book 3: Pipeline Facilities, Subject Number 09-02-02, describes how information would be directed to the appropriate personnel for corrective action. The following is written in the Responsibilities section under Corrective Action:

"Site supervisors are responsible for reviewing routine and annual atmospheric tank inspection reports, and for:

- *Evaluating the need for repairs*
- *Initiating and monitoring repairs*
- *Consulting with the regional engineer, contract inspector, and Operations Services for unusual or major repairs*
- *Ensuring completed repairs are documented*

NOTE: Major repairs include re-leveling a tank, welding within the floor-to-shell critical zone, or any work requiring a hydrotest."

Enbridge feels that the existing procedures adequately define the inspection intervals and timelines, as well as responsibilities associated with the inspection and review of the results. However, Enbridge does acknowledge that at the time of the OPS investigation, a gap did exist in the documentation of corrective action to deficiencies noted during the routine inspections. To enhance the ability to track the progress of the remediation of the deficiencies noted, Enbridge has modified both the Routine and Annual In-Service Tank Inspection Forms to include a Maximo Work Order tracking number for each deficiency requiring corrective action. The remediation activities and follow-up documentation will be tracked in Maximo until the deficiencies are resolved. In addition, the Routine and Annual In-Service Tank Inspection Forms include a review and sign off by the Site Supervisor who is responsible to monitor and record completion of action items identified by the Inspector.

1C. The evidence, as presented during the investigation, clearly shows there were cavities under and around the "D" door that allowed flexion of the fiberglass liner and the floor plates, which contributed significantly to the release. Interviews revealed that there had been an ongoing problem (since 1998) with burrowing animals in the tank yard. Your personnel stated that they addressed the problem by eliminating the animals. However, no additional procedures were written to require continuing surveillance for burrowing animals or anything that could undermine the integrity of the tank bottom. Additionally, there were no procedures written for corrective action, should those conditions be found.

Response:
Enbridge believes that our existing procedures are adequate to address the issue of burrowing animals and that no modification is necessary. Animal nesting is specifically listed on the Routine In-Service Tank Inspection Form, and "Cavities under foundation" is listed in the Maximo Job Plan. The procedures for corrective action are listed in the response to item1B.

2. Enbridge did not begin the monthly in-service inspection of the breakout tanks in the Clearbrook Terminal until January of 2002. The inspections should have begun on May 3, 1999.

Response:
Enbridge had a formal In-Service inspection process in place prior to the May 3, 1999 date specified in §195.432(d). Routine In-Service inspections were completed on a weekly basis in conjunction with tank level gauging. Inspection results were documented on the tank gauging forms and were logged through the tank gauging spreadsheets. In 2002, Enbridge implemented a more formal documentation process. Inspections are now completed monthly and are documented through the Routine In-Service Tank Inspection Report. Enbridge maintains the Routine In-Service Tank Inspection Reports for a minimum of two years.

We trust that the above information sufficiently addresses the concerns noted in your May 19, 2005 letter. Should you have any further questions or concerns, please contact me.

Sincerely,

Mark Willoughby

c: Art Meyer
Steve Irving
Mark Sitek
Charles Kenow - MNOPS

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 27, 2007

Mr. Terry L. McGill
President
Enbridge Energy Partners, LP
1100 Louisiana, Suite 3300
Houston, TX 77002

CPF 3-2007-1011M

Dear Mr. McGill:

On October 17-20, 2005, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Michigan Public Service Commission, pursuant to Chapter 601 of 49 United States Code inspected your procedures for Enbridge Energy's Vector Pipeline operation and maintenance in Griffith, IN.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Enbridge Energy's (Enbridge's) Vector Pipeline plans or procedures, as described below:

1. **§192.465 External corrosion control: Monitoring**
   (d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

   Enbridge's procedure in the Corrosion Control Book, Chapter 3, Section 6 needs to be clarified to indicate the timeframe for the remediation of deficiencies.

2. **§192.715 Transmission lines: Permanent field repair of welds**
Each weld that is unacceptable under §192.241(c) must be repaired as follows:
(b) A weld may be repaired in accordance with §192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;
(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and
(3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains.

Enbridge's procedures in Book 4, Section 02-02-07 need to be clarified to address these issues specifically for gas lines.

3. **§192.727 Abandonment or inactivation of facilities**
(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

Enbridge's procedures in Book 3, Section 06-02-04 need to clarify abandonment versus deactivated pipelines.

4. **§192.751 Prevention of accidental ignition**
Each operator shall take steps 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, including the following:
(c) Post warning signs, where appropriate.

Enbridge's procedures in Book 3, Section 03-02-03 needs to be clarified as to where warning signs are posted.

<u>Response to this Notice</u>

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

Your staff has submitted revised procedures addressing all four items noted in this Notice. PHMSA has reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected. Corrected procedures have been received in electronic format.

No further action is necessary and this case is now closed. Thank you for your cooperation.

In correspondence concerning this matter, please refer to **CPF 3-2007-1011M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 21, 2007

Mr. Terry McGill
President
Enbridge Pipelines LLC – North Dakota
1100 Louisiana
Suite 3300
Houston, TX 77002

CPF 3-2007-5022

Dear Mr. McGill:

On January 25, 2007, the Pipeline and Hazardous Materials Safety Administration (PHMSA) was notified of an incident involving a pipeline operated by Enbridge Pipelines LLC – North Dakota (Enbridge). The incident occurred near Stanley, ND in Mountrail County at the Stanley pump station. The information available to this office indicated that a rupture at the station occurred and resulted in a release of crude oil. Subsequent investigation revealed that the cause of the release was thermal expansion of a section of pipe that was inadvertently isolated while doing some work at the station. The National Response Center (NRC) number assigned to this incident was 824671.

As a result of our review of this incident, it appears that you have committed a probable violation of the pipeline safety regulations, Title 49, Code of Federal Regulations. The probable violation is:

1. **§195.406 Maximum operating pressure.**

§195.406(b) requires that no operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

Enbridge allowed a section of line to exceed 110% of the maximum operating pressure by not providing a pressure relief device on a temporarily idled line filled with crude oil that was inadvertently isolated during a construction project.

On January 25, 2007, Enbridge experienced a failure and release of crude oil at the Stanley Station in North Dakota. Due to construction activity, a section of station piping was isolated with crude oil in the line. The isolation was done with a blind flange on one end and a one-way check valve on the other. During the day, the outside temperature increased approximately 15.3°, from 35.6° F to 50.9° F. The pressure in the line exceeded 100% SMYS (1470 psig) of the pipe and subsequently ruptured. The maximum operating pressure was 980 psig.

Enbridge's procedure 4.2, titled "Requirements for Pressure Relief", specifies when relief devices are needed to be installed on the system. Section 4.2.1 specifically indicates the following: *"Pressure relief shall be installed on isolated systems, such as tank farm piping, manifolds, mainline pumps (if required), and isolated main line loops where a pressure rise phenomenon can occur as a result of thermal expansion."*

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that you be preliminarily assessed a civil penalty of $105,000 for Item 1.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 3-2007-5022** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

Cc: Brian Johnson
North Dakota Manager

Response Options for Pipeline Operators in Compliance Proceedings

The requirements of 49 C.F.R. Part 190, Subpart B (§§ 190.201–190.237) govern response to Notices issued by a Regional Director, Pipeline and Hazardous Materials Safety Administration (PHMSA).

Be advised that all material submitted by a respondent in response to an enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

I. **Procedures for Responding to a NOTICE OF PROBABLE VIOLATION:**

Within 30 days of receipt of a Notice of Probable Violation, the respondent shall respond to the Regional Director who issued the Notice in the following way:

a. When the Notice contains a proposed **CIVIL PENALTY*** --

1. Pay the proposed civil penalty and advise the Regional Director of the payment. This authorizes PHMSA to make findings and to close the case with prejudice to the respondent. Payment terms are outlined below;

2. Submit written explanations, information, or other materials in response to the allegations and/or seek elimination or mitigation of the proposed civil penalty. Refer to 49 C.F.R. § 190.225 for assessment considerations, which include the respondent's ability to pay and the effect on the respondent's ability to stay in business, upon which civil penalties are based; or

3. Request a hearing as described below to contest the allegations and/or proposed assessment of a civil penalty.

b. When the Notice contains a proposed **COMPLIANCE ORDER*** --

1. Notify the Regional Director that you intend to take the steps in the proposed compliance order;

2. Submit written explanations, information, or other materials in answer to the allegations in the Notice and object to or seek clarification of the proposed compliance order items in whole or in part; or

3. Request a hearing as described below to contest the allegations and/or proposed compliance order items;

c. <u>When the Notice contains a **WARNING ITEM** --</u>

No written response is required. The respondent is warned that if it does not take appropriate action to correct these items, enforcement action will be taken if a subsequent inspection reveals a violation.

* Failure of the respondent to respond to the Notice within 30 days of receipt constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

II. Procedures for Responding to a NOTICE OF AMENDMENT*--

Within 30 days of receipt of a Notice of Amendment, the respondent shall respond to the Regional Director who issued the Notice in the following way:

a. Notify the Regional Director of your plans to address the inadequacies identified in the Notice;

b. Submit written explanations, information, or other materials in answer to the allegations in the Notice and/or object to or seek clarification of the proposed amendment items in whole or in part; or

c. Request a hearing as described below to contest the allegations in the Notice.

* Failure of the respondent to respond to the Notice within 30 days of receipt constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

III. Procedure for Requesting a Hearing

A request for a hearing must be in writing and accompanied by a statement of the issues that the respondent intends to raise at the hearing. The issues may relate to the allegations, new information, or to the proposed compliance order or proposed civil penalty amount. Refer to 49 C.F.R. § 190.225 for assessment considerations upon which civil penalties are based. A respondent's failure to specify an issue may result in waiver of the right to raise that issue at the hearing. The respondent's request must also indicate whether or not respondent will be represented by counsel at the hearing. Failure to request a hearing in writing within 30 days of receipt of a Notice waives the right to a hearing. In addition, if the amount of the proposed civil penalty or the proposed corrective action is less than $10,000, the hearing will be held by telephone, unless the respondent submits a written request for an in-person hearing. Complete hearing procedures can be found at 49 C.F.R. § 190.211.

IV. **Extensions of Time**

An extension of time to prepare an appropriate response to a Notice may be granted, at the agency's discretion, following submittal of a written request to the Regional Director. The request must indicate the amount of time needed and the reasons for the extension. The request must be submitted within 30 days of receipt of the Notice.

V. **Freedom of Information Act**

Any material prepared by PHMSA, including the violation report, the Notice, and any order issued in this case, and any material provided to PHMSA by the respondent, may be considered public information and subject to disclosure under the Freedom of Information Act (FOIA). If the information you provide is security sensitive, privileged, confidential or may cause your company competitive disadvantages, please clearly identify the material and provide justification why the documents, or portions of a document, should not be released under FOIA. If we receive a request for your material, we will notify you if PHMSA, after reviewing the materials and your provided justification, determines that withholding the materials does not meet any exemption provided under the FOIA. You may appeal the agency's decision to release material under the FOIA at that time. Your appeal will stay the release of those materials until a final decision is made.

VI. **Small Business Regulatory Enforcement Fairness Act Information**

The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of the Pipeline and Hazardous Materials Safety Administration, call 1-888-REG-FAIR (1-888-734-3247) or go to http://www.sba.gov/ombudsman/dsp_faq.html.

VII. PAYMENT INSTRUCTIONS

Civil Penalty Payments of Less Than $10,000

Payment of a civil penalty of less than $10,000 proposed or assessed, under Subpart B of Part 190 of the Pipeline Safety Regulations can be made by certified check, money order or wire transfer. Payment by certified check or money order (containing the CPF Number for this case) should be made payable to the "Department of Transportation" and should be sent to:

Federal Aviation Administration
Mike Monroney Aeronautical Center
Financial Operations Division (AMZ-341) P.O. Box 25082
Oklahoma City, OK 73125-4915

Wire transfer payments of less than $10,000 may be made through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfer should be directed to the Financial Operations Division at (405) 954-8893, or at the above address.

Civil Penalty Payments of $10,000 or more

Payment of a civil penalty of $10,000 or more proposed or assessed under Subpart B of Part 190 of the Pipeline Safety Regulations must be made wire transfer (49 C.F.R. § 89.21 (b)(3)), through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfers should be directed to the Financial Operations Division at (405) 954-8893, or at the above address.

INSTRUCTIONS FOR ELECTRONIC FUND TRANSFERS

(1) RECEIVER ABA NO. 021030004	(2) TYPE/SUB-TYPE (Provided by sending bank)
(3) SENDING BANK ABA NO. (Provided by sending bank)	(4) SENDING BANK REF NO. (Provided by sending bank)
(5) AMOUNT	(6) SENDING BANK NAME (Provided by sending bank)
(7) RECEIVER NAME TREAS NYC	(8) PRODUCT CODE (Normally CTR, or as provided by sending bank)
(9) BENEFICIAL (BNF) = AGENCY LOCATION CODE BNF = /ALC-69-14-0001	(10) REASONS FOR PAYMENT Example: PHMSA - CPF # / Ticket Number/Pipeline Assessment number

INSTRUCTIONS: You, as sender of the wire transfer, must provide the sending bank with the information for blocks (1), (5), (7), (9), and (10). The information provided in Blocks (1), (7), and (9) are constant and remain the same for all wire transfers to the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #1 - RECEIVER ABA NO. - "021030004". Ensure the sending bank enters this 9-digit identification number; it represents the routing symbol for the U.S. Treasury at the Federal Reserve Bank in New York.

Block #5 - AMOUNT - You as the sender provide the amount of the transfer. Please be sure the transfer amount is punctuated with commas and a decimal point. **EXAMPLE: $10,000.00**

Block #7 - RECEIVER NAME - "TREAS NYC". Ensure the sending bank enters this abbreviation. It must be used for all wire transfers to the Treasury Department.

Block #9 - BENEFICIAL - AGENCY LOCATION CODE - "**BNF=/ALC-69-14-0001**". Ensure the sending bank enters this information. This is the Agency Location Code for the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #10 - REASON FOR PAYMENT - "**AC-payment for PHMSA Case # /** To ensure your wire transfer is credited properly, enter the case number/ticket number or Pipeline Assessment number, and country."

NOTE: A wire transfer must comply with the format and instructions or the Department cannot accept the wire transfer. You as the sender can assist this process by notifying the Financial Operations Division (405) 954-8893 at the time you send the wire transfer.

May 2007

AUG 2 -

AUG 2 4 2007

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

PART A – INSPECTION IDENTIFICATION

CPF #: 3-2007-5022	[ ] Gas [ ] LNG X Hazardous Liquid	**Date of Inspection:** January 25, 2007
PHMSA/State Inspector name and organization: Hans Shieh / PHMSA Central Region		

PART B – OPERATOR INFORMATION

Pipeline operator/owner: Enbridge Pipelines LLC – North Dakota	**OPID:** 15774	**Inspection location:** Stanley, ND	**Inspection Unit #:** 1373
Company Official name, title, telephone, FAX#: Mr. Terry McGill President 713-821-0003; 713-821-2080 (fax)		**Mailing address of Company Official:** 1100 Louisiana Houston, TX 77002	

Nature and size of operator's system (total miles, HCA miles, products, environmental conditions, employees):

Enbridge Pipelines, Inc. operates one of the largest crude oil and petroleum products pipeline systems in Canada and the United States. Enbridge transports these products through more than 8500 miles of pipeline with diameters ranging from 12 inches to 48 inches. Enbridge has more than 1200 employees for the entire company.

The Enbridge Pipelines LLC - ND system has approximately 558 miles of pipeline in North Dakota and Minnesota. 66.7 miles of that system have been classified as HCAs. The system delivers crude oil from northwest North Dakota and delivers the product to Clearbrook, MN.

Portion of system inspected (locations and facilities):

Stanley, ND pump station. Accident investigation of pipe failure. Investigation was not on-site.

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

PART C – VIOLATION and CIVIL PENALTY INFORMATION
Note: Information shown in Part C of this Pipeline Safety Violation Report relates to probable violations, proposed compliance orders, and proposed civil penalties

VIOLATION NUMBER 1

Identify the regulation violated with the part, section, and most specific paragraph of Title 49, such as 192.309(b)(3)(ii):

195.406(b) Maximum operating pressure.

How did the operator violate the regulation?:

Enbridge allowed a section of piping at the Stanley, ND pump station to exceed 110% of the maximum operating pressure which led to the rupture of the pipe.

Provide additional detail regarding the violation, including the duration and extent of the violation:

In November of 2006, Enbridge began the process of replacing a mainline pump at the Stanley, ND station and reconfiguring the suction and discharge piping. During the construction, Enbridge inadvertently left a section of line isolated aboveground with crude oil in it. The line was capped on one end with a blind flange and isolated on the other end with a one way check valve. See attachment B for the drawings of where the isolated section was located.

On January 25, 2007, the isolated line was still exposed when the ambient temperature increased from 35.6° F to 50.9° F during the day. As a result, the line ruptured due to thermal expansion of the product. The volume of the spill was 215 barrels. Estimated thermal calculations obtained from Enbridge indicated that the pressure in the pipeline could have reached 1837 psi. The specifics of the line section that failed were as follows: 10.75" diameter, 0.188" wall thickness, X-42 pipe. The design pressure of this pipe section was 1470 psi. The maximum operating pressure of this pipe was 980 psig, per Enbridge's 7000-1 Report (Exhibit G).

Enbridge's procedure 4.2, titled "Requirements for Pressure Relief", specifies when relief devices are needed to be installed on the system. Section 4.2.1 specifically indicated the following: *"Pressure relief shall be installed on isolated systems, such as tank farm piping, manifolds, mainline pumps (if required), and isolated main line loops where a pressure rise phenomenon can occur as a result of thermal expansion."*

Provide a description of the evidence:

Attachment A is a map of the Enbridge ND system

Attachment B is a schematic of the station and a close-up of the isolated section

Attachment C is a copy of NRC Reports 824671

Attachment D is a copy of Enbridge's procedure.

Attachment E is a copy of Enbridge's internal investigation

Attachment F is a copy of Pictures taken by Enbridge personnel at the site.

Attachment G is a copy of the Final 7000-1 report for this incident.

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

How might this violation have impacted public safety? Was this potential impact in an HCA?:

This violation had minimal impact to public safety and did not occur in an HCA. The location of the rupture was in a pump station, whose access is strictly controlled by Enbridge personnel.

How might this violation have impacted the environment? Was this potential impact in an HCA?:

This violation had minimal impact to the environment and did not occur in an HCA. The location was in a pump station and the release was contained entirely on company property. The product did not migrate into any water sources or underground wells.

Person(s) interviewed [include each person's name, title, and an explanation of why this person's knowledge is important in establishing the violation:

Matt Faith, Supervisor of Engineering and Technical Services.

Comments of person(s) interviewed regarding the violation:

Mr. Faith indicated that when he talked to the technician at the station, the technician replied that he should have taken the flap off the one way check valve, but simply forgot to do so.

For IM Inspections only, enter the Area Finding & Risk Category data (from Table 1A or 1B of the *Enforcement Guidance for Liquid and Gas Transmission IM*)

- Area Finding: click here to enter
- Risk Category (A-E) click here to enter

Proposed action: (check one)	X	**NOPV w/ civil penalty**	[ ]	**NOPV w/ civil penalty & compliance order**
	[ ]	**NOPV w/ compliance order**	[ ]	**Other:** [describe - click here]

Civil Penalty Assessment Considerations For This Violation:

<Complete sections C1, C2 and C3 only if a civil penalty is proposed for this violation>

C1 — Degree of the operator's culpability:

Enbridge is well aware of the regulations, and their procedures reflected the need for over-pressure protection.

C2 — Good faith in attempting to achieve compliance:

None – Was an oversight.

C3 — Additional comments applicable to civil penalty:

In the past, Enbridge has shown good faith in trying to achieve compliance. Enbridge was very cooperative during this investigation.

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

PART D – History of Prior Offenses

Note: Complete Part D only if at least one of the probable violations has a proposed civil penalty

PRIOR OFFENSES (for the 5 year period prior to the approx. date of this inspection's NOPV letter)				
Date of Final Order	**CPF #**	**What type of enforcement action(s) (CO, CP) are in the Final Order ?**	**Number of offenses in Final Order**	**Identify the regulation(s) violated (Part, Section, and specific Paragraph)**
5/17/2004	4-2002-5015	CO, CP	2	195.432(a)

Press TAB in cell above to add rows

Note: This case is for Enbridge Energy LP (Op Id 11169). There were no previous citations with CP for Enbridge Pipelines LLC (Op Id 15774). They are all under the same company, but have different operator id's.

Inspector's signature & organization **Date:**

Hans Shieh 8/20/07

PHMSA Region Director's signature **Date:**

Ivan A. Huntoon 8/20/07

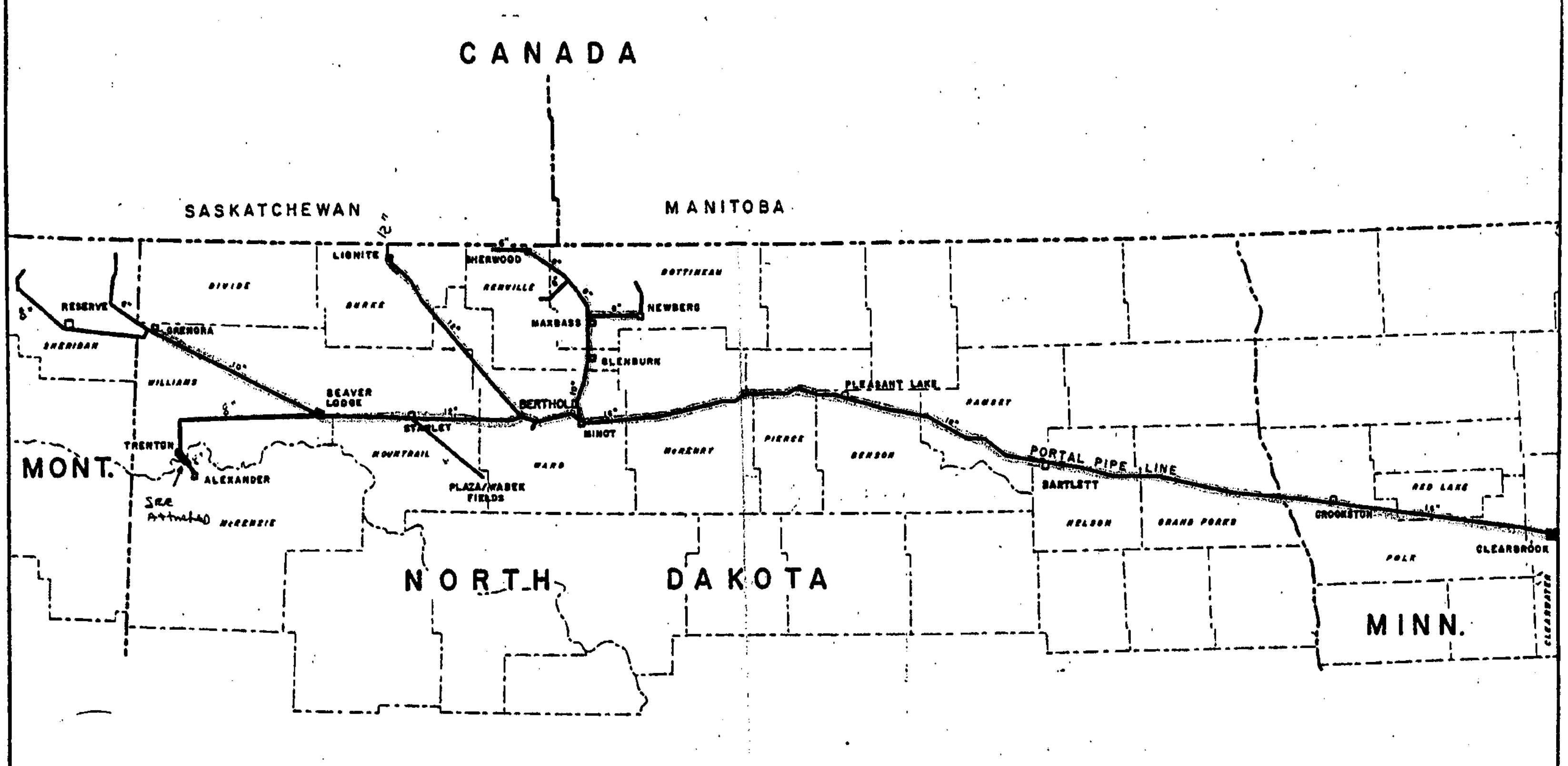
(Rev. 3/07)

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit A			
Name of Operator: **Enbridge Pipelines LLC – North Dakota**			
Violation number(s) supported by the evidence	**Evidence (attached)**	**Obtained from**	**Identifying Witness**
N/A	Map of the Enbridge Pipelines – North Dakota system.	Enterprise	N/A

Press TAB in above cell for more rows



LEGEND

- ▫ PUMP STATION
- PIPELINE
- Pipeline - DOT regulated

NO	DATE	DESCRIPTION	DWN	CHKD	APP
1	1/3/84	ADDED STATIONS			

REVISIONS

PORTAL PIPE LINE COMPANY

SYSTEM MAP

DWN J.D.S.	DATE 8-3-83	SCALE 1"=30 MI.
CHKD		DWG. NO.
APP		MAP-300

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

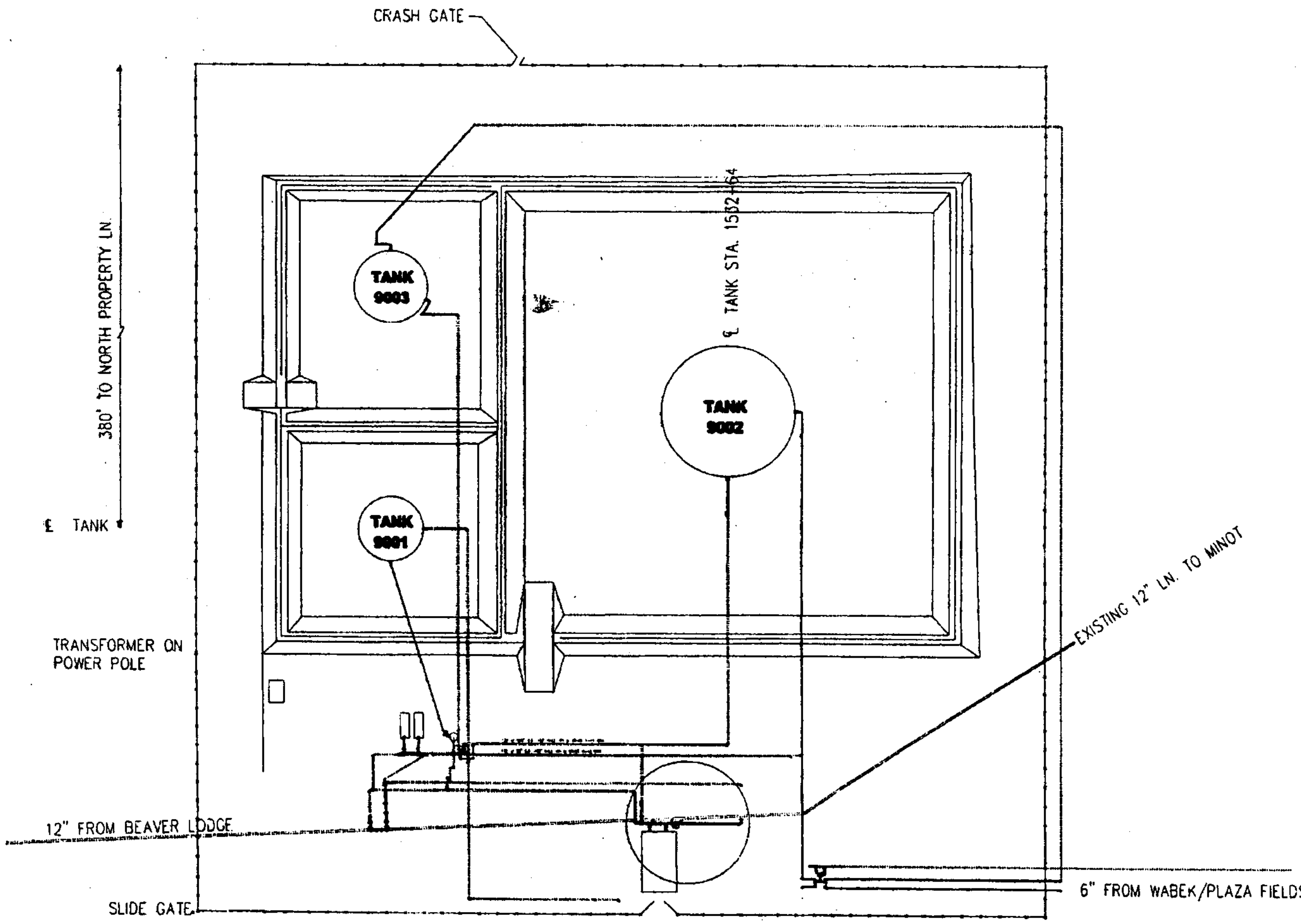
Evidence Exhibit B

Name of Operator: **Enbridge Pipelines LLC – North Dakota**

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	Schematic of the station and a close-up of the locked in section	Enbridge	N/A

Press TAB in above cell for more rows

RESPONSE #1



NO	REVISION	DATE	APPR	BY
-	-	-		
-	-	-		
2				
1	ADDED SECOND PUMP	9/10/04		DJV

ENBRIDGE PIPELINES (ND)

STANLEY (ND) STATION

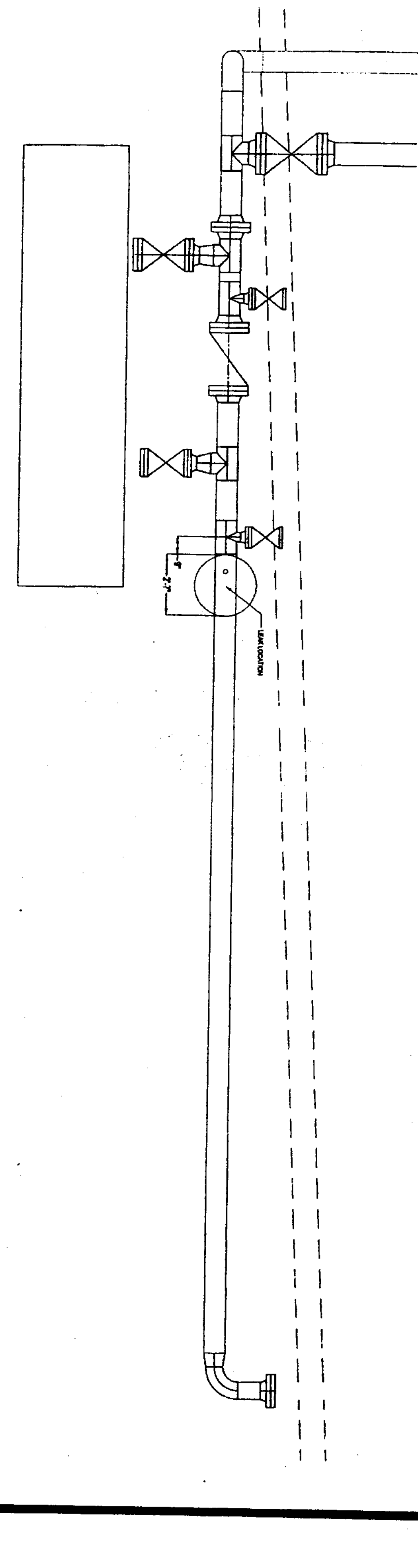
PLOT PLAN

PROJECT:

SCALE:	1"=60'-0"	DATE:	3/2/2002	DRAWN:	DJV
CHECK:	S. HARRIM	APPR:	S. HARRIM	DATE:	3/24/2002

B-82-1.2-17051-0-17 PLT

RESPONSE #1



PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit C

Name of Operator: **Enbridge Pipelines LLC – North Dakota**

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	NRC Report 824671	PHMSA Central Region	N/A

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PHMSA Pipeline & Hazardous Materials Safety Administration

HMIS->INCIDENTS->TELEPHONICS

(Version 2.0.00 PROD) Rules of Behaviour Home Lc M

[Return to Search]

<< Previous 1..1 of 1 << Save >>

☐ Rescinded **Comments** (max 250 characters)

NRC Number:	**824671**		
Call Date:	**01/25/2007**	**Call Time:**	**19:00:03**

Caller Information

First Name:	GARY	Last Name:	BLOWERS
Company Name:	ENBRIDGE PIPELINES ND LLC		
Address:	2505 16TH AVE		
City:	MINOT	State:	ND
Country:	USA	Zip:	
Phone 1:	7016282092	Phone 2:	
Organization Type:	PRIVA	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	GARY	Last Name:	BLOWERS
Company Name:	ENBRIDGE PIPELINES ND LLC		
Address:	2505 16TH AVE		
City:	MINOT	State:	ND
Country:	USA	Zip:	
Phone 1:	7016282092	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	ND	County:	MOUNTRAIL
Nearest City:	STANLEY	Zip Code:	

CALLER HAD NO FURTHER INFORMATION.

Latitude

Degrees: Minutes: Seconds: Quadrant:

Longitude

Degrees: Minutes: Seconds: Quadrant:

Distance from City:		Direction:	
Section:	27 NW OF SV	Township:	156N
Range:	91W	Milepost:	

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit D

Name of Operator: **Enbridge Pipelines LLC – North Dakota**

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	Enbridge Procedure, Section 4.2	Enbridge	N/A

Press TAB in above cell for more rows

4.2 Requirement for Pressure Relief

The following section identifies locations and situations where pressure relief capabilities are typically required.

When evaluating the risk of exceeding MOP, consideration of the following factors may warrant a more conservative approach to line protection:

a. frequency of facility use;
b. dependency on proper operator response and equipment reliability; and
c. condition and age of the pipe.

It is important to recognize that changes to piping, valving, and/or control configuration may be sufficient to eliminate the risk of MOP violation and should be considered before concluding that pressure relief is required.

4.2.1 Stations, Terminals, and Idle Loops

Pressure relief is required on low-pressure valve manifold or metering systems (PN 20 [ANSI 150]) when such facilities could experience main line pressure. For metering systems, pressure relief shall be provided both upstream and downstream of the meters, with set points configured as to preferentially relieve metered flows. This minimizes the frequency of unmetered reliefs while ensuring that the system is protected even if there is an equipment failure within the metering system itself.

***Comment:** Pressure relief for metering systems should not relieve unmetered oil unless the relief volumes can be measured. If relief does occur upstream of the meters, relief volumes may be determined by tank gauging. Refer to Engineering Standard No. D09-101: Oil Measurement, Mechanical.*

Pressure relief shall be installed on isolated systems, such as tank farm piping, manifolds, main line pumps (if required), and isolated main line loops where a pressure rise phenomenon can occur as a result of thermal effects. Small capacity relief valves or cross connecting piping shall be considered for these installations.

While it is acceptable to relieve small, non-contaminating thermal expansion volumes into an adjacent piping facility, it is important to consider the cascade effect of pressure relief devices. Sequential relief valve settings should be stepped down for each piping system downstream of the first relief device, ultimately relieving into an open vessel.

4.2.2 Mainline Locations

Mainline pressure relief may be required to protect the pipe upstream of delivery locations due to the piping configuration, frequency of remote valve operation, and the potential for a holding PCV failure at these locations.

Mainline pressure relief may also be required due to the static head resulting from significant pipeline elevation profile changes.

4.2.3 Hydraulic Evaluation

It may not be immediately evident whether site specific conditions lead to the requirement for pressure relief. A hydraulic study of the situation may be required.

RESPONSE #3

When a pressure relief system is required in accordance with Engineering Standard No. D12-104: Pressure Relief, then the full flow pressure relief valve shall be located upstream of the meters; refer to Figure 6.3: Single Metering Facilities Recommended Layout.

Comment: *Receipt metering systems shall have both upstream and downstream pressure relief with the upstream rupture disc set at 345 kPa (50 psi) higher than the pressure relief valve setting on the downstream side. Refer to Engineering Standard No. D12-104: Pressure Relief, Figure 6.1B: Relief Systems — Receipt Metering.*

Pressure relief protecting custody transfer equipment shall have a rupture disc installed between the relief device and the upstream isolation valve to confirm the relief system integrity. Proper instrumentation should also be provided to alert the operator of a relief condition and enable time logging of the event for manual reconciliation of relieved volumes.

Pressure relief with full flow capability shall be provided when the pipeline operations of connecting carriers could result in system overpressure.

Thermal relief shall be provided on all above ground sections of pipe that can be isolated and shall be set to relieve at the MOP of the connected piping. On each meter run, the thermal relief shall be located downstream of the meter to eliminate the possibility of unmetered discharge. A thermal relief valve shall be required on each end of the prover pipe or near each launching chamber.

Comment: *Experience has indicated that the ball can freeze in the chamber and the prover can overpressure with only one thermal relief.*

Although product relieved to sump is not measured in conventional ways, it is important, for product inventory management purposes, to be able to determine the point from which product is relieved. On liquid systems, open telltale drains will provide a means to determine the point of relief. On NGL service, drain lines from relief valves may require in-line flow switches or piping provision for their possible future installation. Inventory management of amounts relieved is handled by Operations, through sump level measurement at scheduled station checks on routine checks, and recorded in the station log.

4.10.3 Overhead Crane System

A dual rail overhead crane system shall be installed. The structure and crane shall be designed with sufficient capacity for the regular maintenance activities and removal of the heaviest component in the meter system, including valves, strainers, piping, or meters; refer to Clause 4.2.1.6: Ease of System Operation, and Clause 4.3.1: General Layout.

RESPONSE #3

4.12.7 Control Valve Stations

Isolation and bypass valves shall be provided for all station discharge pressure control valve installations. The Project Engineer shall determine requirements for isolation and bypass valves for delivery or holding pressure control valve stations.

Isolation and bypass valves shall be gate valves.

Drain valves shall be provided upstream and downstream of all control valves.

4.12.8 Pressure Relief Requirements

Pressure relief for station and terminal piping systems shall be installed, when it can be shown there is a probability for exceeding the maximum operating pressure.

A pressure relief system must be provided in the design to protect piping systems for the following circumstances:

a. low pressure systems, when positioning of valves could subject tank manifold, meter manifold, or other low pressure piping to main line pressure;
b. piping that can be isolated by closing the valves, when thermal heating of the piping will cause overpressure by thermal expansion; and
c. piping, which in an emergency condition could be exposed to fire, shall be provided with a means of relieving thermal expansion and vapors generated. This is of particular concern in systems containing NGL.

The following methods or combination of methods can achieve protection of pipeline equipment against excessive pressure:

a. emergency closure of the valves to isolate the facility from the pressure source;
b. high discharge pressure shutdown controls, which will stop pumps that are the source of the overpressure; and
c. fluid relief by a pressure relieving device, such as a pressure safety surge protection valve or rupture disk to a drain or vent system.

Pressure relief valves shall be used in applications for which there is a demonstrable need to provide a level of protection over that provided by computer based and "hard wired" control systems.

The set pressure of a relieving device shall be as high as feasible to reduce the likelihood of discharge. The Project Engineer should allow for a relief valve setting of the MOP of the affected piping, plus 8 per cent, less the differential across the valve at the design flow rate.

Thermal relief valves shall be selected to prevent "simmering." Simmering occurs when the initial relief setting and the reset pressure are too far apart; thus, the valve does not reset properly after relieving.

Pipeline hydraulics must be carefully evaluated to avoid exceeding the MOP of the system. Surge relief valves on main line service shall typically be a Daniel "Dan-Flo" or equal. The relief valve shall be installed with a positive shutoff valve upstream to facilitate verification of the valve setting, according to the requirements of CSA-Z662. A downstream maintenance isolation valve should also be installed. A flow switch or fiber

PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit E

Name of Operator: **Enbridge Pipelines LLC – North Dakota**

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	Enbridge's Internal Investigation Report	Enbridge	N/A
1	Enbridge's Thermal Calculations	Enbridge	N/A

Press TAB in above cell for more rows

Enbridge LP Incident Post-Mortem Template

ENBRIDGE

- Stanley Station Piping Rupture
- January 25, 2007

Jan 2006 Version

Table of Contents

ENBRIDGE

Post-Mortem Participants

ENBRIDGE

Date:	Location:	
Name	**Job Title**	**Company**
Matt Faith	Supervisor, Engineering & Technical Services	EPND
Kevin Gault	Safety Coordinator	EPND
Gary Blowers	Area Supervisor	EPND
Mike Moeller	Operations Manager	EPND

Incident Description

ENBRIDGE

Date (DD/MM/YY)	25/01/2007
Time	3:50 p.m. CST
Location (Identify country, region, MP)	Stanley Station, Stanley, ND Mountrail County
High Level Summary of Event	Station piping ruptured due to thermal expansion.

Incident Description

Insert relevant pictures to assist with incident description

ENBRIDGE

Notifications

ENBRIDGE

Date	Time	Notification Summary
January 25, 2007 January 25, 2007	3:50 p.m. CST 3:52 p.m.	Control Center:Brian Dolezal notified Control Center. Joe Dobson notified Mike Moeller of possible leak
January 25, 2007	3:53 p.m.	**On-Call Staff:** Brian Dolezal notified Gary Blowers
January 25, 2007	3:50 p.m.	**First Responder:** Brian Dolezal was working on site
N/A		Public Emergency Responders (911, Police, Fire, etc.):

Notifications

ENBRIDGE

Date	Time	Notification Summary
January 25, 2007	3:59 p.m. 3:55 p.m.	Management: Gary Blowers contacted Mike Moeller Control Center notified Brian Johnson
January 25, 2007	 5:55 p.m. 6:05 p.m. 6:10 p.m.	Regulatory Agencies (DOT, TSB, NEB, etc.): Gary Blowers Contacted NRC, Rep. 824671, talked to McCrossen Gary contacted ND Health Dept. Rick Robinson (ND Health Dept.) returned call.
January 25, 2007	 3:58 p.m. 5:45 p.m.	Contractors: Gary contacted Diamond B Trucking SK&S On Site
N/A		Shippers:

Notifications

ENBRIDGE

Date	Time	Notification Summary
N/A		Mutual Aid Groups:
N/A		Others as Applicable:

Notifications

ENBRIDGE

Learnings – Outline deficiencies and opportunities for improvement (missed notifications, duplications, limitations with existing communication tools (cell phones, radios), inaccuracy of phone listings, inadequate functionality of reference tools, etc.).

- NDDH was contacted using their toll free number (800-472-2121) to report the release.
- Kris Roberts of the NDDH Water Quality Dept stated his inspector at Sawyer landfill (where contaminated soil was hauled) was surprised to see the trucks from an Enbridge spill he was not aware of.
- Communication link break down was determined to be internal to the NDDH (per Kris Roberts).
- **Solution:** Once we notify NDDH via the 800 number, we need to complete an "Environmental Incident Form" on-line at http://www.health.state.nd.uc/ehs/eir/eirform.htm

Site Safety – Hazards

ENBRIDGE

Hazards – Detail the hazards encountered during the emergency (ignition sources, weather, vapors, electrical, lighting, etc.). Specify if the hazards were handled in accordance with O&MP standards.

- **Benzene Vapors-**Half masks worn until concentrations confirmed to be less than 0.5 ppm
- **Free Product –** Hazard Assessment completed prior to equipment used to clean up free product as per Book 7 Section 04-02-01
- **Freezing Temperatures-**Slips/Trips/Falls discussed at tailgate meetings

Learnings – Outline deficiencies and opportunities for improvement.

- **Unfamiliarity with operation of benzene monitoring equipment**
- **Solution: Kevin Gault to cover benzene monitoring during Hazwopper training in spring of 2007.**

Site Safety – PPE

ENBRIDGE

Personal Protective Equipment – Outline types of personal protective equipment used (hearing protection, safety glasses, respirator, etc.).

- **FR Clothing, Safety Boots, Half Mask Respirators with organic vapor cartridge, high visibility vests, gloves, air monitors**
- **Fire extinguishers with safety watch**

Learnings – Outline deficiencies and opportunities for improvement.

- Not all contractors show up on site with FR clothing
- Solution: Kevin Gault to research and purchase some disposable FR coveralls for contractor use

Site Safety – Safety & Response Equipment

ENBRIDGE

Safety & Response Equipment - Detail types of safety equipment used (firefighting, signage, gas detection, first aid, communication tools, etc.).

- Minot ER Equipment Trailer mobilized.
- Shovels, squeegees used extensively
- Back hoe and front end loader used to scrape up and load contaminated soil/snow

Learnings – Outline deficiencies and opportunities for improvement.

- None noted

Safety – Personal Injuries

ENBRIDGE

Personal Injuries – Detail any close calls or injuries associated with the incident.

- None

Learnings – Outline deficiencies and opportunities for improvement.

Public Safety

ENBRIDGE

Public Safety – Outline actions taken to protect public safety (protective zones, evacuations, elimination of ignition sources, traffic control, notification, etc.).

- Majority of spill was inside station fence line
- Where spill was outside station fence line, barricade tape was used to mark off restricted area.

Learnings – Outline public complaints, deficiencies and opportunities for improvement.

- None noted

Site Security & Administration

ENBRIDGE

Security and Administrative – Detail the site security and administrative controls used during the incident response (access control points, area isolation, road blocks, permitting, sign-in logs, gas detection logs, etc.).

- Sign-In log utilized
- Contractors Safety and site Orientated
- Visitors reported to Office designated as command post
- Adsorbent pads used at entry/exit to hot zone for decontamination

Learnings – Outline deficiencies and opportunities for improvement (hazards not addressed, site control and access issues, inadequate emergency responder coordination, poor communications, etc.).

- None Noted

Response Team Mobilization

ENBRIDGE

Mobilization – Detail timelines for the mobilization of the emergency response teams (first responders, secondary responders, mutual aid resources, police and fire departments, etc.).

- Operations Staff were on site at time of incident
- Mike Massine notified to mobilize men and equipment from Minot at 3:57 p.m.
- Minot based men and equipment arrive on sit at 5:15 p.m.
- SK&S Crew arrived on site at 5:45 p.m.

Learnings – Outline deficiencies and opportunities for improvement.

- **None noted**

Incident Command System (ICS)

ENBRIDGE

ICS – Detail ICS roles and responsibilities, and if a unified command structure was initiated.

- IC – Mike Massine
- Safety Officer – Kevin Gault
- Ops Chief – Gary Blowers

Learnings – Outline deficiencies and opportunities for improvement.

- **None noted**

Shutdown / Isolation / Discharge Control

ENBRIDGE

Release Control – Detail the measures taken to control the discharge at the source. Specify whether or not they were in accordance with O&MP procedures.

- Brian Dolezal requested ECC to shutdown Stanley pumps per procedure
- Brian closed SYMV104 manually
- Gary requested ECC to close SYMV108

- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- **None noted**

Containment

ENBRIDGE

Containment – Detail the containment measures implemented. Specify whether or not they were in accordance with O&MP procedures.

- Free product migrated to the east and collected in a naturally low spot outside station fence
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- **Free product could have been kept inside the fence line with station berming**
  - **Develop station containment program and budget for starting in 2008**

Recovery

ENBRIDGE

Recovery – Detail the effectiveness of the recovery measures used during the response. Specify whether or not they were in accordance with O&MP procedures.

- Naturally occurring low spot allowed majority of free product to be recovered using tank truck.
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- None noted

Sensitive Areas

ENBRIDGE

Sensitive Areas – List all potentially impacted sensitive areas (as defined in the O&MP standards) and outline the effectiveness of the emergency response in protecting them.

- Town of Stanley is an HCA, however not affected at by release
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- None noted

Remediation Disposal

ENBRIDGE

Remediation Disposal – Detail the disposal of the recovered material and contaminated debris. Specify whether or not it was in accordance with O&MP procedures.

- Contaminated materials hauled to Sawyer Landfill by Earthworks trucks
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- None noted

Communications

ENBRIDGE

Communications – Detail the effectiveness of the communication procedures. Specify whether or not they were in accordance with O&MP procedures.

- Cell phones were used extensively with good success.
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- None Noted

Transportation

ENBRIDGE

Transportation – Detail the effectiveness of the modes of transportation (water, air, land) used during the response.

- All travel was by land and site has good access immediately off paved highway

Learnings – Outline deficiencies and opportunities for improvement.

- None noted

Personnel Support

ENBRIDGE

Personnel Support – Detail the level of support provided to personnel associated with the response (accommodations, meals, administration, work space, etc.).

- Stanley station/office used as command area/dining area/warm-up shelter with good success

Learnings – Outline deficiencies and opportunities for improvement.

- None Noted

Equipment Maintenance & Support

ENBRIDGE

Equipment Maintenance & Support – Detail the effectiveness of the emergency response equipment maintenance support. Specify whether or not all emergency equipment was inspected and accounted for after use (in accordance with O&MP procedures).

- Squeegees and shovels were used extensively and accounted for
- Adsorbent pads were used and disposed of properly
- All in accordance with O&MP procedures

Learnings – Outline deficiencies and opportunities for improvement.

- None Noted

Procurement

ENBRIDGE

Procurement – Detail the effectiveness of the procurement system for personnel, response equipment and support equipment.

- Earth Movers and SK&S contacted and crews and equipment mobilized effectively

Learnings – Outline deficiencies and opportunities for improvement.

- United Rentals after hours number was not answered when called to rent light plant
- Solution: Mike Moeller to call and confirm number and procedure

Documentation

Documentation – Detail how records of the response were developed and maintained. Specify whether or not the incident events were documented in accordance with O&MP standards.

- ECC used 'Receiving Emergency Information Form"
- Gary, Kevin, Mike used note pads to document notes

Learnings – Outline deficiencies and opportunities for improvement.

- Some responders/personnel do not keep sufficient notes
- Solutions:
  - Raise Awareness in ER Exercises (done for ice slotting Feb 13, 2007) Action Mike Moeller
  - Helene Long, company attorney, is invited to discuss documentation do's and don'ts at ER Team Meeting July 10 Action Mike Moeller

Investigation Findings

ENBRIDGE

Investigation Findings – Detail the incident investigation findings (immediate, physical and root causes), and associated improvement opportunities.

- Immediate Causes – Failure to follow procedure, inadequate protective equipment
  - Several references in Engineering Standards to ensure thermal protection is provided for section of pipe with potential to be isolated.
  - No thermal relief was installed on isolated piping after modification to piping
- Basic Causes – Inadequate evaluation of change
  - Development of project scope did not include a hazard operations review
- Corrective Actions
  - Raise awareness of dead legs and their susceptibility to thermal expansion with operations staff
    - **Action: Mike Moeller to Review in local EH&S meetings by March 31, 2007**
  - Perform a system review of dead leg piping
    - **Action: Matt Faith to complete a system wide review of station/terminal piping, identify dead legs and develop mitigation plan by July 31, 2007**
  - Revise O&MP to include guidelines to ensure modifications to piping do not create dead legs.
    - **Action: Matt Faith to issue critical revision to GSM by March 15, 2007**

Incident Review Action Plan

ENBRIDGE

Action Plan – Detail action items, specifying assigned responsibilities and timelines.

- **Action: Mike Moeller to raise awareness of dead legs in local EH&S meetings by March 31, 2007**
- **Action: Matt Faith to complete a system wide review of station/terminal piping, identify dead legs and develop mitigation plan by July 31, 2007**
- **Action: Matt Faith to issue critical revision to GSM by March 15, 2007**
- **Action: Mike Moeller to raise awareness to the importance of documentation of events, actions, calls, etc during a response via ER Exercises February 13, July 11 and August 8, 2007. (Ice slotting exercise completed February 13,2007)**
- **Action: Mike to invite Helene Long (company attorney) to address legal aspect of documentation to ER Team at its July meeting.**
- **Action; Mike Moeller to call and confirm United Rentals after hours number and procedure for procuring rental equipment after hours by March 15, 2007.**
- **Action: Matt Faith to develop station containment program and budget for starting in 2008.**
- **Action: Kevin Gault to research and purchase disposable FR coveralls to be used by contractors on site of a release clean up. Due April 30, 2007.**
- **Action: Kevin Gault to review benzene monitor operation at Hazwopper training in spring of 2007. (Scheduled for February 27 and March 20, 2007)**
- **Action: Mike Moeller to ensure reporting procedure to NDDH is communicated and procedure is updated in ERD for 2008 revision. (email sent from Rachael Shetka to all supervisors February 7, 2007)**

Other Items of Interest

ENBRIDGE

EQUATIONS

Vtp	**= Vstd x CTL x CPL x CTS x CPS** is the volume (in cubic meters) required at test pressure P (in Bars), and temperature T (in 'C).	(1)
Vstd	is the volume (in cubic meters) at standard conditions (T = 15'C, and P = 0 Bars gauge). **=[3.14159 x (D - 2 x wt)^2)/4] x L** D = Outside Diameter in meters, wt = Wall Thickness in meters, and L = length in meters.	(2)
CTL	is the correction factor for the effect of temperature on liquid hydrocarbons, as per API Table 54. is a function of density (at std condictions) and temperature. rounded to 4 decimal places.	
CPL	is the correction factor for the effect of pressure on liquid hydrocarbons, as per API Table 11.2.1M. is a function of density (at std condictions) and temperature. rounded to 4 decimal places.	
CTS	is the correction factor for the effect of temperature on steel pipe. **=(1+((T-15)*3.35*10^(-5)))** rounded to 4 decimal places. T = Temperature in 'C. 3.35x10^(-5) = Coefficient of cubical expansion for mild steel, per °C	(3)
CPS	is the correction factor for the effect of temperature on steel pipe. **=(1+(P*ID/(2.1*10^6*wt)))** rounded to 4 decimal places. P = pressure in Bars. ID = inner diameter in meters. wt = wall thickness in meters. 2.1x10^6 = Modulus of elasticity for steel, in bars.	(4)

Conversation Table

6.625	in	to	168.275	mm
0.5	in	to	12.7	mm
20	ft	to	6.096	m
0	mile	to	0	m
1200	psi	to	82.7	Bar
0	F	to	-17.8	C

Stanley Pressure Temperature Correlations

100% SMYS is 1470 psi
1.25 X this amount may have been generated by as little as a 9 degree rise in temp
It is not unreasonable that this could have resulted in the piping due to the cold night (-10 C) and warm (5 C) afternoon temp

Enter OD, wt, L, and density. If you know the volume of the 'station', adjust the length to obtain the required volume.

Pipe/Crude Data

Pipe Size:	273.05 OD (mm)	10.75	OD (in)
	4.7752 w.t. (mm)	0.188	w.t. (in)
Length:	6.0 meters	0.03788	miles
Volume at STD	5.690 m3		
Density of Crude	870 kg/m3 at 15 C		

Enter initial pressure and temperature. Note that temp. is to be entered in 'C, and should be the average temp.

Initial Conditions

Pressure:	58.6 Bars	850 psi
Temperature:	2 C	
CTL:	1.0105	
CPL:	1.0037	
CTS:	0.9996	
CPS:	1.0015	
C eq	1.0154	
Volume at Init Cond	5.778 m3	

Enter final pressure. The final average temperature will be calculated.

Final Conditions

Pressure:	126.7 Bars	1837 psi
Temperature:	10.50 C	8.50
CTL:	1.0036	
CPL:	1.0085	
CTS:	0.9998	
CPS:	1.0033	
C eq	1.0153	
Volume at final Cond	5.777 m3	

PIPELINE SAFETY VIOLATION REPORT

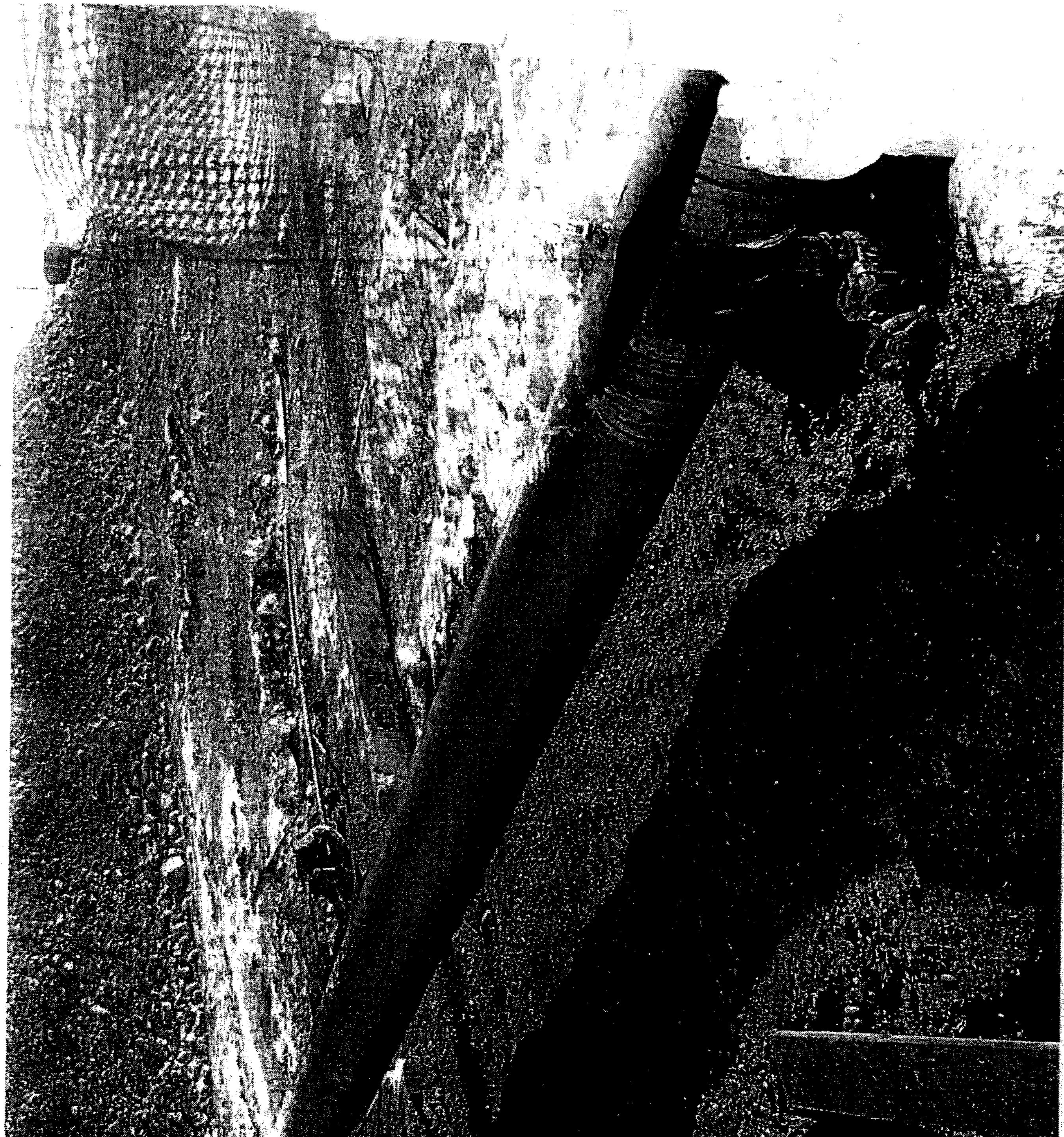
United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit F

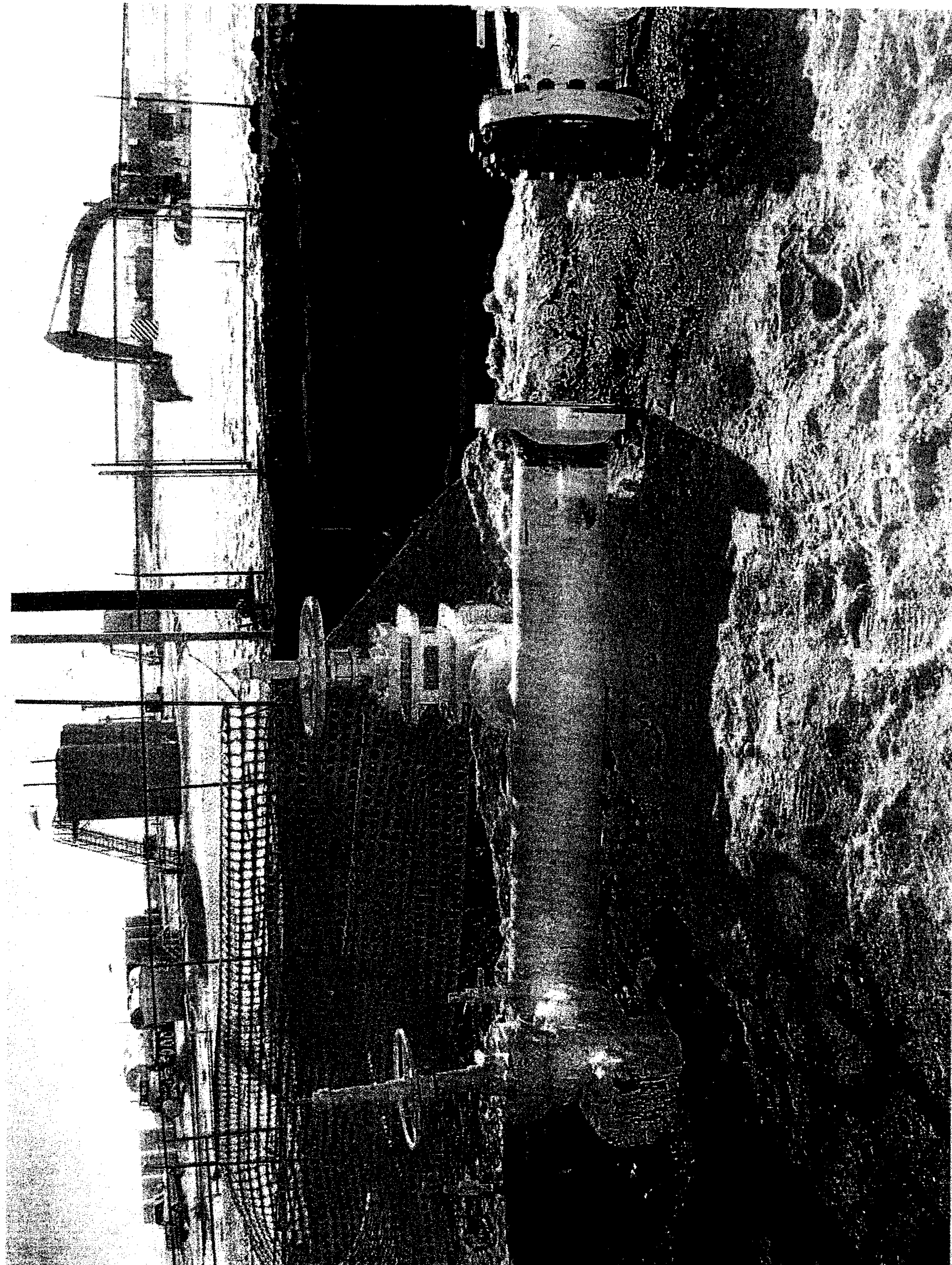
Name of Operator: Enbridge Pipelines LLC – North Dakota

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	Pictures of the release site	Enbridge	N/A

RESPONSE #6

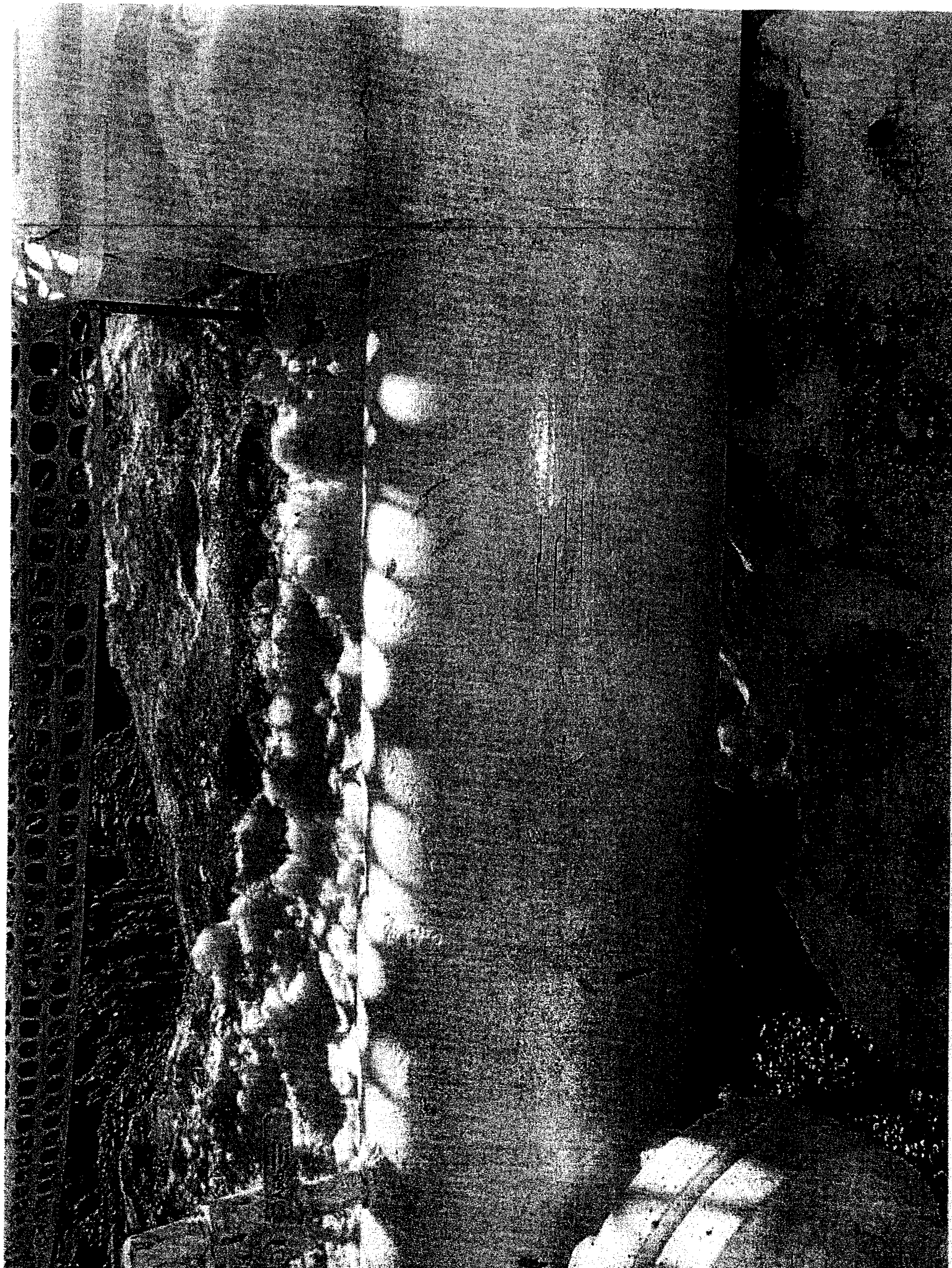


RESPONSE #8

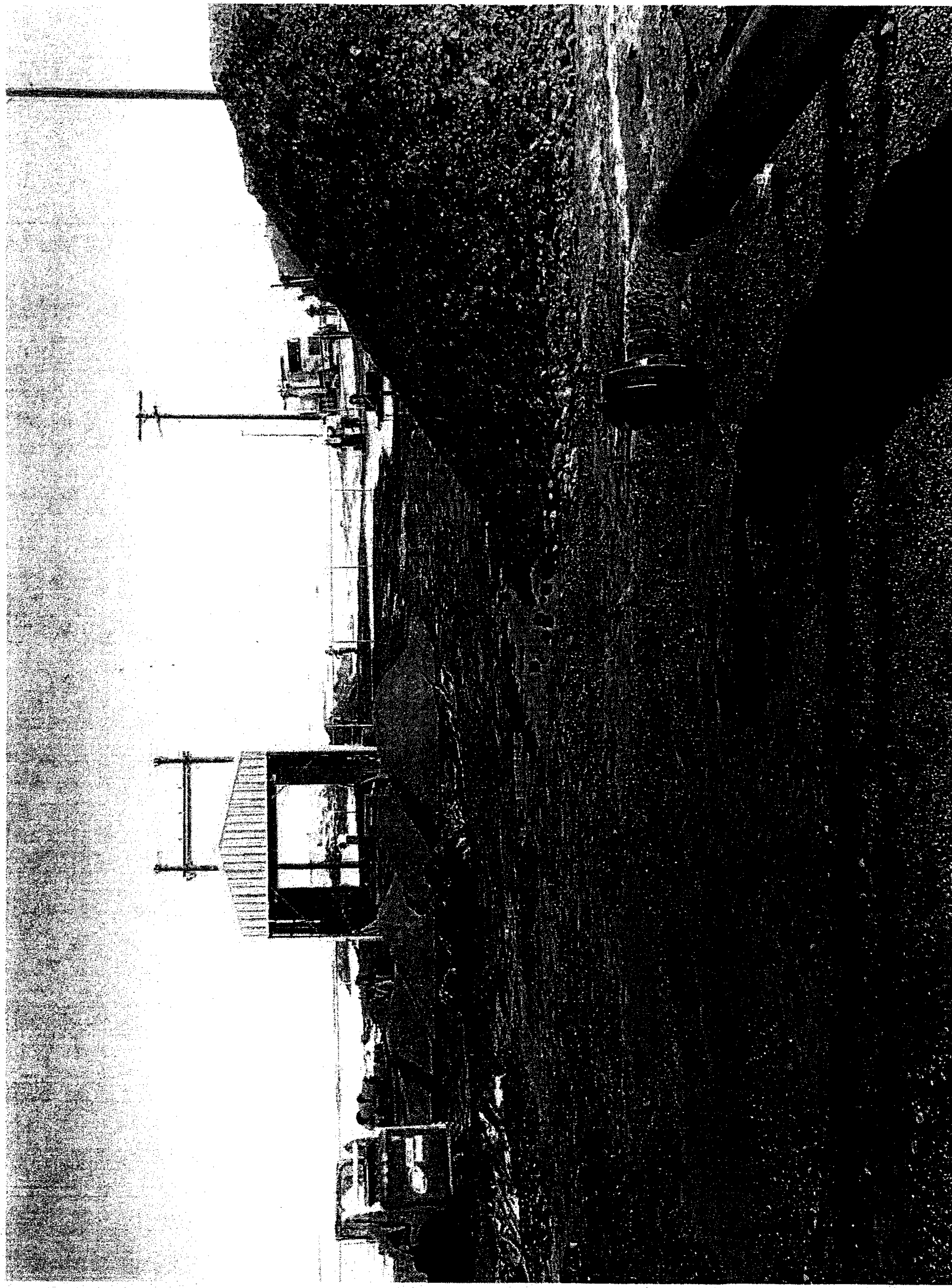


RESPONSE #8

RESPONSE #8

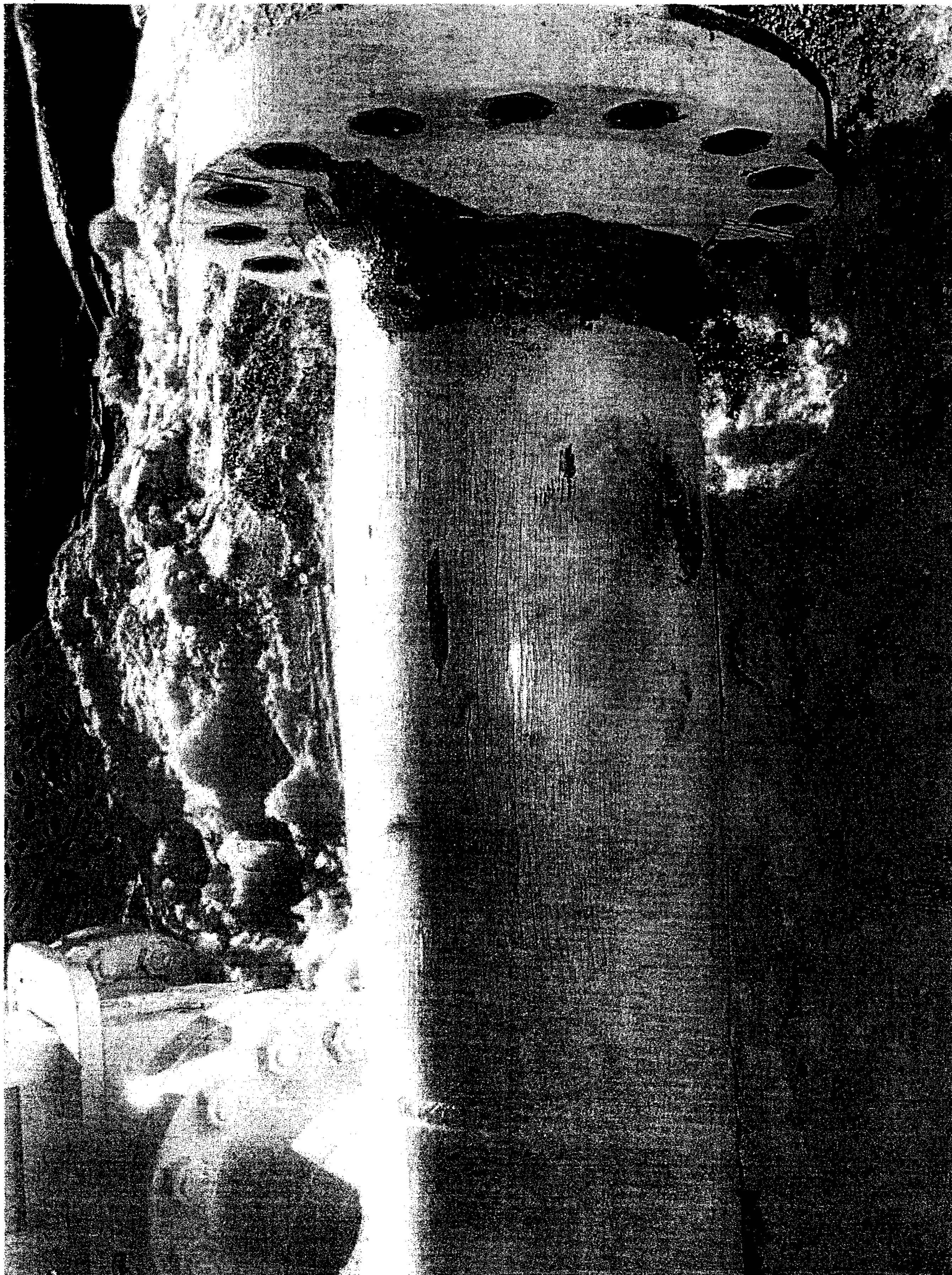


RESPONSE #8



RESPONSE #8

RESPONSE #8



PIPELINE SAFETY VIOLATION REPORT

United States Department Of Transportation
Pipeline and Hazardous Materials Safety Administration

Evidence Exhibit G

Name of Operator: **Enbridge Pipelines LLC – North Dakota**

Violation number(s) supported by the evidence	Evidence (attached)	Obtained from	Identifying Witness
1	7000-1 Report	PHMSA	N/A

Press TAB in above cell for more rows

Form Approved
OMB No. 2137-0047

U.S. Department of Transportation
Research and Special Programs Administration

ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date feb 21,2007
No. 20070043 -- 5589
(DOT Use Only)

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov.*

PART A – GENERAL REPORT INFORMATION Check: ☐ Original Report ☒ Supplemental Report ☒ Final Report

1. a. Operator's OPS 5-digit Identification Number (if known) / 15774 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if known) / /
   c. Name of Operator ENBRIDGE PIPELINES (NORTH DAKOTA) LLC
   d. Operator street address 2505 16TH ST SW, SUITE 200
   e. Operator address MINOT WARD ND 58701
   City, County, State and Zip Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident
/ 1545 / hr. / 01 / month / 25 / day /2007/ year

3. Location of accident
(If offshore, do not complete a through d. See Part C.1)
   a. Latitude: 48-17-10 Longitude: 102-25-30
   (if not available, see instructions for how to provide specific location)
   b. STANLEY MOUNTRAIL
   City, and County or Parish
   c. ND 58784
   State and Zip Code
   d. Mile post/valve station ○ or survey station no. ○
   (whichever gives more accurate location)

4. Telephone report
/ 824671 / NRC Report Number / 01 / month / 25 / day /2007/ year

5. Losses *(Estimated)*

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 0
Cost of emergency response phase	$ 62000
Cost of environmental remediation	$ 6000
Other Costs	$ 0
(describe)	

Operator Losses:

Value of product lost	$ 750
Value of operator property damage	$ 7000
Other Costs	$ 0
(describe)	
Total Costs	$ 75750

6. Commodity Spilled ● Yes ○ No
(If Yes, complete Parts a through c where applicable)
   a. Name of commodity spilled CRUDE OIL
   b. Classification of commodity spilled:
   ○ HVLs /other flammable or toxic fluid which is a gas at ambient conditions
   ○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditions
   ○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
   ● Crude oil

c. Estimated amount of commodity involved :
● **Barrels**
○ **Gallons (check only if spill is less than one barrel)**
Amounts:
Spilled : 215
Recovered: 200

CAUSES FOR SMALL SPILLS ONLY (5 gallons to under 5 barrels) *(For large spills [5 barrels or greater] see Part H)*

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Outside Force Damage**
○ **Material and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

PART B – PREPARER AND AUTHORIZED SIGNATURE

VALERIE K. LAVIK
(type or print) Preparer's Name and Title
(701) 857-0852
Area Code and Telephone Number
VALERIE.LAVIK@ENBRIDGE.COM
Preparer's E-mail Address
(701) 857-0809
Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Code and Telephone Number

Form RSPA F 7000-1 (01-2001)

PART C – ORIGIN OF THE ACCIDENT (Check all that apply)

1. Additional location information
   a. Line segment name or ID **STANLEY STATION**
   b. Accident on Federal land other than Outer Continental Shelf ☐ Yes ■ No
   c. Is pipeline interstate? ■ Yes ☐ No

Offshore: ☐ Yes ■ No *(complete d if offshore)*
d. Area ______ Block # ______
State / ______ / or Outer Continental Shelf ☐

2. Location of system involved (*check all that apply*)
   - [X] Operator's Property
   - [ ] Pipeline Right of Way
   - [X] High Consequence Area (HCA)?
   Describe HCA **US OPA**

3. Part of system involved in accident
   - ☐ Above Ground Storage Tank
   - ☐ Cavern or other below ground storage facility
   - ■ Pump/meter station; terminal/tank farm piping and equipment, including sumps
   - ☐ Other *Specify:* ______
   - ☐ Onshore **pipeline**, including valve sites
   - ☐ Offshore **pipeline**, including platforms

If failure occurred on Pipeline, complete items a - g:

a. Type of leak or rupture
   - ☐ Leak: ☐ Pinhole ☐ Connection Failure *(complete sec. H5)*
     ☐ Puncture, diameter *(inches)* ______
   - ☐ Rupture: ☐ Circumferential – Separation
     ☐ Longitudinal – Tear/Crack, length *(inches)* ______
     Propagation Length, total, both sides *(feet)* ______
   - ☐ N/A
   - ☐ Other ______

b. Type of block valve used for isolation of immediate section:
   Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
   Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ______ ft

d. Distance between valves ______ ft

e. Is segment configured for internal inspection tools? ☐ Yes ☐ No

f. Had there been an in-line inspection device run at the point of failure? ☐ Yes ☐ No ☐ Don't Know
   ☐ Not Possible due to physical constraints in the system

g. If *Yes*, type of device run (*check all that apply*)

Device	Year run
☐ High Resolution Magnetic Flux tool	Year run: ______
☐ Low Resolution Magnetic Flux tool	Year run: ______
☐ UT tool	Year run: ______
☐ Geometry tool	Year run: ______
☒ Caliper tool	Year run: ______
☐ Crack tool	Year run: ______
☐ Hard Spot tool	Year run: ______
☐ Other tool	Year run: ______

4. Failure occurred on
   - ☐ Body of Pipe ■ Pipe Seam ☐ Scraper Trap
   - ☐ Pump ☐ Sump ☐ Joint
   - ☐ Component ☐ Valve ☐ Metering Facility
   - ☐ Repair Sleeve ☐ Welded Fitting ☐ Bolted Fitting
   - ☐ Girth Weld
   - ☐ Other *(specify)* ______

Year the component that failed was installed: / **1983** /

5. Maximum operating pressure *(MOP)*
   a. Estimated pressure at point and time of accident: **1700** *PSIG*
   b. MOP at time of accident: **980** *PSIG*
   c. Did an overpressurization occur relating to the accident? ■ Yes ☐ No

PART D – MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / **10** / in.
2. Wall thickness / **.12** / in.
3. Specification **API X42** SMYS / **42000** /
4. Seam type **ERW**
5. Valve type **N/A**
6. Manufactured by **UNKNOWN** in year / ______ /

PART E – ENVIRONMENT

1. Area of accident
   - ☐ In open ditch
   - ☐ Under pavement
   - ■ Above ground
   - ☐ Underground
   - ☐ Under water
   - ☐ Inside/under building
   - ☐ Other ______

2. Depth of cover: ______ inches

PART F – CONSEQUENCES

1. Consequences *(check and complete all that apply)*

a.

	Fatalities	Injuries
Number of operator employees:		**0**
Contractor employees working for operator:		**0**
General public:		**0**
Totals:		**0**

b. Was pipeline/segment shutdown due to leak? ■ Yes ☐ No
   If Yes, how long? **0** days **6** hours **0** minutes

c. Product ignited ☐ Yes ■ No d. Explosion ☐ Yes ■ No

e. ☐ Evacuation *(general public only)* / ______ / people
   Reason for Evacuation:
   - ☐ Precautionary by company
   - ☐ Evacuation required or initiated by public official

f. Elapsed time until area was made safe:
   / ______ / hr. / ______ / min.

2. Environmental Impact
   a. Wildlife Impact: Fish/aquatic ☐ Yes ■ No
      Birds ☐ Yes ■ No
      Terrestrial ☐ Yes ■ No
   b. Soil Contamination ■ Yes ☐ No
      If Yes, estimated number of cubic yards: **296**
   c. Long term impact assessment performed: ☐ Yes ■ No
   d. Anticipated remediation ■ Yes ☐ No
      If Yes, check all that apply: ☐ Surface water ☐ Groundwater ☒ Soil ☒ Vegetation ☐ Wildlife

   e. Water Contamination: ☐ Yes ■ No *(If Yes, provide the following)*
      Amount in water ______ barrels
      Ocean/Seawater ☐ No ☐ Yes
      Surface ☐ No ☐ Yes
      Groundwater ☐ No ☐ Yes
      Drinking water ☐ No ☐ Yes *(If Yes, check below.)*
      ☐ Private well ☐ Public water intake

H5 – MATERIAL AND/OR WELD FAILURES

Material

14. ☐ Body of Pipe => ☐ Dent ☐ Gouge ☐ Bend ☐ Arc Burn ☐ Other ____________

15. ☐ Component => ☐ Valve ☐ Fitting ☐ Vessel ☐ Extruded Outlet ☐ Other ____________

16. ☐ Joint => ☐ Gasket ☐ O-Ring ☐ Threads ☐ Other ____________

Weld

17. ☐ Butt => ☐ Pipe ☐ Fabrication ☐ Other ____________

18. ☐ Fillet => ☐ Branch ☐ Hot Tap ☐ Fitting ☐ Repair Sleeve ☐ Other ____________

19. ☐ Pipe Seam => ☐ LF ERW ☐ DSAW ☐ Seamless ☐ Flash Weld ☐ HF ERW ☐ SAW ☐ Spiral ☐ Other ____________

*Complete a-g if you indicate **any** cause in part H5.*

a. Type of failure:
☐ Construction Defect => ☐ Poor Workmanship ☐ Procedure not followed ☐ Poor Construction Procedures
☐ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? ☐ Yes ☐ No

c. Was part which leaked pressure tested before accident occurred? ☐ Yes, *complete d-g* ☐ No

d. Date of test: /__________/ yr. /______/ mo. /______/ day

e. Test medium: ☐ Water ☐ Inert Gas ☐ Other ____________________

f. Time held at test pressure: /______/ hr.

g. Estimated test pressure at point of accident: ____________________ *PSIG*

H6 – EQUIPMENT

20. ☐ Malfunction of Control/Relief Equipment => ☐ Control valve ☐ Instrumentation ☐ SCADA ☐ Communications ☐ Block valve ☐ Relief valve ☐ Power failure ☐ Other ____________

21. ☐ Threads Stripped, Broken Pipe Coupling => ☐ Nipples ☐ Valve Threads ☐ Dresser Couplings ☐ Other ____________

22. ☐ Seal Failure => ☐ Gasket ☐ O-Ring ☐ Seal/Pump Packing ☐ Other ____________

H7 – INCORRECT OPERATION

23. ■ Incorrect Operation

a. Type: ☐ Inadequate Procedures ☐ Inadequate Safety Practices ■ Failure to Follow Procedures
☐ Other ____________________

b. Number of employees involved who failed a post-accident test: drug test: /___U___/ alcohol test /___U___/

H8 – OTHER

24. ☐ Miscellaneous, *describe:* ____________________

25. ☐ Unknown
☐ Investigation Complete ☐ Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART I – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

STANLEY STATION CONTAINS PIPING FROM A DIESEL UNIT THAT WAS REMOVED IN 2004. THIS PIPING WAS USED FOR EXISTING PISTON PUMPS THAT INJECT PRODUCT FROM THE STANLEY TANKS UNTIL NOVEMBER OF 2006. IN NOVEMBER OF 2006, DISCHARGE PIPING FROM THE INJECTION PUMPS WAS MODIFIED. THIS MODIFICATION LEFT APPROXIMATELY 80 FEET OF 10£1 PIPE IDLED SUBJECT TO DISCHARGE PRESSURE. OF THIS 80 FEET OF PIPE, 20 FEET WAS ISOLATED WITH A CHECK VALVE. JANUARY 25TH WAS THE WARMEST DAY OF THE YEAR WITH LOCAL TEMPERATURES REACHING 43 DEGREES F. THIS 20 FEET OF PIPING ISOLATED FROM THE REST WAS EXPOSED TO THERMAL EXPANSION. THIS CREATED A PRESSURE LARGE ENOUGH TO RUPTURE THE PIPE ON THE DOWNSTREAM SIDE OF THE CHECK VALVE. THE CHECK THEN ALLOWED OIL TO FLOW FROM THE MAINLINE THROUGH THE DISCHARGE PIPING, THROUGH THE CHECK AND OUT OF THE RUPTURED STATION PIPE. PRESSURE WAS ESTIMATED USING CALCULATIONS BASED ON OBSERVED TEMPERATURE RISE. THE RELEASE WAS ISOLATED, CONTAINED AND IMMEDIATELY CLEANED UP. THE FLAPPER WAS REMOVED FROM THE CHECK VALVE TO ELIMINATE THE CAUSE OF THE INCIDENT.

PART G – LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? Yes ■ No
2. Was the release initially detected by? (check one):
   - CPM/SCADA-based system with leak detection
   - Static shut-in test or other pressure or leak test
   - ■ Local operating personnel, procedures or equipment
   - Remote operating personnel, including controllers
   - Air patrol or ground surveillance
   - A third party
   - Other (specify) ______________
3. Estimated leak duration days 0 hours 0

PART H – APPARENT CAUSE

Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. See the instructions for guidance.

H1 – CORROSION

1. External Corrosion
2. Internal Corrosion

(Complete items a – e where applicable.)

a. Pipe Coating: Bare; Coated

b. Visual Examination: Localized Pitting; General Corrosion; Other ______________

c. Cause of Corrosion: Galvanic; Atmospheric; Stray Current; Microbiological; Cathodic Protection Disrupted; Stress Corrosion Cracking; Selective Seam Corrosion; Other ______________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
No; Yes, Year Protection Started: /____________/

e. Was pipe previously damaged in the area of corrosion?
No; Yes => Estimated time prior to accident: /______/ years /______/ months Unknown ☐

H2 – NATURAL FORCES

3. Earth Movement => Earthquake; Subsidence; Landslide; Other ______________
4. Lightning
5. Heavy Rains/Floods => Washouts; Flotation; Mudslide; Scouring; Other ______________
6. Temperature => Thermal stress; Frost heave; Frozen components; Other ______________
7. High Winds

H3 — EXCAVATION DAMAGE

8. Operator Excavation Damage (including their contractors/Not Third Party)
9. Third Party *(complete a-f)*

a. Excavator group: General Public; Government; Excavator other than Operator/subcontractor

b. Type: Road Work; Pipeline; Water; Electric; Sewer; Phone/Cable; Landowner-not farming related; Farming; Railroad; Other liquid or gas transmission pipeline operator or their contractor; Nautical Operations; Other ______________

c. Excavation was: Open Trench; Sub-strata (boring, directional drilling, etc...)

d. Excavation was an ongoing activity (Month or longer) Yes; No; If Yes, Date of last contact /________/

e. Did operator get prior notification of excavation activity?
Yes; Date received: /______/ mo. /______/ day /__________/ yr. No
Notification received from: One Call System; Excavator; Contractor; Landowner

f. Was pipeline marked as result of location request for excavation? No; Yes *(If Yes, check applicable items i - iv)*
   - i. Temporary markings: Flags; Stakes; Paint
   - ii. Permanent markings:
   - iii. Marks were (check one): Accurate; Not Accurate
   - iv. Were marks made within required time? Yes; No

H4 – OTHER OUTSIDE FORCE DAMAGE

10. Fire/Explosion as primary cause of failure => Fire/Explosion cause: Man made; Natural
11. Car, truck or other vehicle not relating to excavation activity damaging pipe
12. Rupture of Previously Damaged Pipe
13. Vandalism

Enbridge Pipelines (Lakehead) L.L.C.
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Superior, WI 54880-5247
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Jay Johnson
Senior Compliance Coordinator
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jay.johnson@enbridge.com

ENBRIDGE

September 18, 2007

Ivan A Huntoon
Central Region – PHMSA
901 Locust Street, Room 462
Kansas City MO 64106-2641

RE: CPF - 3 - 2007 - 5022

Dear Mr. Huntoon:

Pursuant to the above mentioned Pipeline and Hazardous Materials Safety Administration (PHMSA) Notice of Probable Violation and Proposed Civil Penalty, Enbridge Pipelines North Dakota LLC (EPND) is submitting written explanations, information and other materials regarding the merits of the allegations. EPND is seeking mitigation or elimination of the proposed civil penalty as outlined in the Response Options for Pipeline Operators in Compliance Proceedings.

EPND's request to mitigate the proposed civil penalty is based on:

1. EPND's effective response to incident and cleanup,
2. EPND's prompt and effective mitigative and corrective actions,
3. Minimal impact to Public Safety and the Environment,
4. EPND's cooperative response and open relationship with PHMSA,
5. EPND's excellent operational history.

As detailed in the post mortem template, (previously submitted) EPND responded quickly and effectively to isolate and limit the release. Ensuing containment, all free product was recovered and all impacted soil was properly disposed. The release was totally contained on EPND property and therefore did not pose any threats to public safety. However, ground water monitoring wells were installed in the vicinity to ensure no product escaped the containment area.

Following the incident, a committee comprised of subject matter experts from Operations, Engineering and Management developed a list of corrective actions and lessons learned utilizing the Det Norske Veritas Systematic Cause Analysis Technique. Both root cause and non-critical improvements were identified. From this a revision to the Operating and Maintenance Manual was issued which was immediately reviewed by all engineering and field personnel. The Incident Report was also circulated for review. In addition, EPND has completed a Facility Integrity Risk Assessment on all station facilities and has focused efforts to address dead leg, idle and low flow piping.

During the course of investigating this incident, EPND kept Central Region PHMSA updated via phone and electronic communications such as; photographs, thermal calculations and the root cause analysis. It is our policy to determine the cause and communicate the corrective measures within the Enbridge companies to avert any possible reoccurrences. As part of our investigations, we value the comments and concerns expressed by PHMSA and take them all into consideration.

Materials attached for your review are:

- Operating and Maintenance Procedures Manual revision
- Incident Investigation corrective action status list
- Facility Integrity Assessment Program

In conclusion, EPND is committed to operating in full regulatory compliance and has an excellent record of working jointly with PHMSA to ensure pipeline safety. Therefore, we respectfully request that PHMSA review our request to mitigate or eliminate the proposed civil penalties. If you have any questions or require additional information please contact Jay Johnson in our Superior office at 715/394-1512.

Sincerely,

Steve Irving by TmP

Steve Irving
Director, System Integrity and Compliance

cc: Janet Holder
Brian Johnson
Jay Johnson
Terry McGill
Mark Willoughby

Gathering Systems O&MP Manual

ENBRIDGE

REVISION REQUEST

Name: Matt Faith Date: 02/21/07

Subject Title: Overview of Pipeline Repair/Replacement/Relocation/Abandonment
Subject No.: 11.1 (page 141)

Existing wording: None

Proposed wording: Considerations when modifying station or above ground piping:

1. Does modification create a section of dead leg below ground piping that could result in a corrosion risk? Modify design or refer to "Facilities Integrity Management Program guideline for the management of corrosion of facility piping" for mitigative requirements.
2. Does modification create a section of isolated piping that could be exposed to overpressure due to thermal effects? Refer to Enbridge Standard D12-104 Pressure Relief for requirements.
3. Can the modification be done to eliminate, reduce or simplify the existing piping?

Reason for Change: Added to clarify design requirements and reference Enbridge standards to incorporate when changing above ground or station piping. This is a recommendation following the overpressure incident at Stanley Station.

CRITICAL REVISION 01

Forward to the Manual Administrator, Val Lavik , in the EPND Regional Office

Item	Description	Status	Comments
1	Raise awareness of dead legs and their susceptibility to thermal expansion	Complete	Awareness raised in safety meeting as incident and OMP revision was discussed. Specifically the thermal effect was discussed and ways to avoid, and requirements of the Engineering standard
2	Perform System review of dead leg piping	Complete	Additional resources were obtained to complete a total system review prior to 3rd Quarter.
3	Revise O&MP to include guidelines to ensure modifications do not create dead legs	Complete	Reader is referred to engineering standard and advised to consult it when modifying piping

ENBRIDGE

Facility Integrity Assessment Program

For The Enbridge North Dakota System

Overview

- Problem Statement
- Risk Ranking Overview
- Risk Ranking Sample Station
- Results
- Corrosion Management Process

Problem Statement

- Pipeline systems are inherently susceptible to corrosion, both external and internal.
- The intent of this program is to serve as a guideline for the identification of dead legs, idle pipe and low flow pipe at station and terminal facilities.
- This program has been adapted from Enbridge mainline system and has not been done before on the North Dakota system.

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Risk Ranking Factors

- There are six factors considered in this program. Each factor is given a relative weight. These weights are determined from Industry and Enbridge standards. They are:

Environmental (EV)	= 45%
Piping Age (AG)	= 10%
Usage (UG)	= 20%
Line Product (LP)	= 15%
Size (SZ)	= 5%
Physical Distribution (PD)	= 5%

Risk Ranking Score

- Each Risk Ranking Factor will be assigned a score between 1 and 5 from the following definitions.

Environmental (EV) = 45%

- **Category 5** - Zones close to water; in the event of a leak, crude oil will go to the source and remedial action will be downstream using booms or contingency equipment.
- **Category 4** - Zones close to water channels; in case of leak it has to be stopped by closing the site drainage block valves.
- **Category 3** - Pipes that are in headers and manifolds that can be initially contained but depending on the leak can drain to a water channel
- **Category 2** - Pipe completely inside of dikes or piping that in case of a leak the product can be confined without risk of water contamination.
- **Category 1** - Not specified

Piping Age (AG) = 10%

- **Category 5** - Over 40 years old
- **Category 4** - From 30 to 40 years old
- **Category 3** - From 20 to 30 years old
- **Category 2** - From 10 to 20 years old
- **Category 1** - Less than 10 years old

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Usage (UG) = 20%

- **Category 5** - Completely idle
- **Category 4** - Used rarely or not often
- **Category 3** - Used once a year
- **Category 2** - Used twice a year
- **Category 1** - Used every month

Note, if idle leg is purged with Nitrogen then it is not at risk and is not considered in the program

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Line Product (LP) = 15%

- **Category 5** - Heavy Sour Crude Oil
- **Category 4** - Medium Sour and Heavy Sweet Crude Oils
- **Category 3** - Light Sour and Medium Sweet Crude Oils
- **Category 2** - Diesel, Gasoline and Kerosene
- **Category 1** - Light Sweet Crude Oil, Condensate and NGL

*All Sour is category 5, Blended Sweet is category 4 and Sweet is category 3.

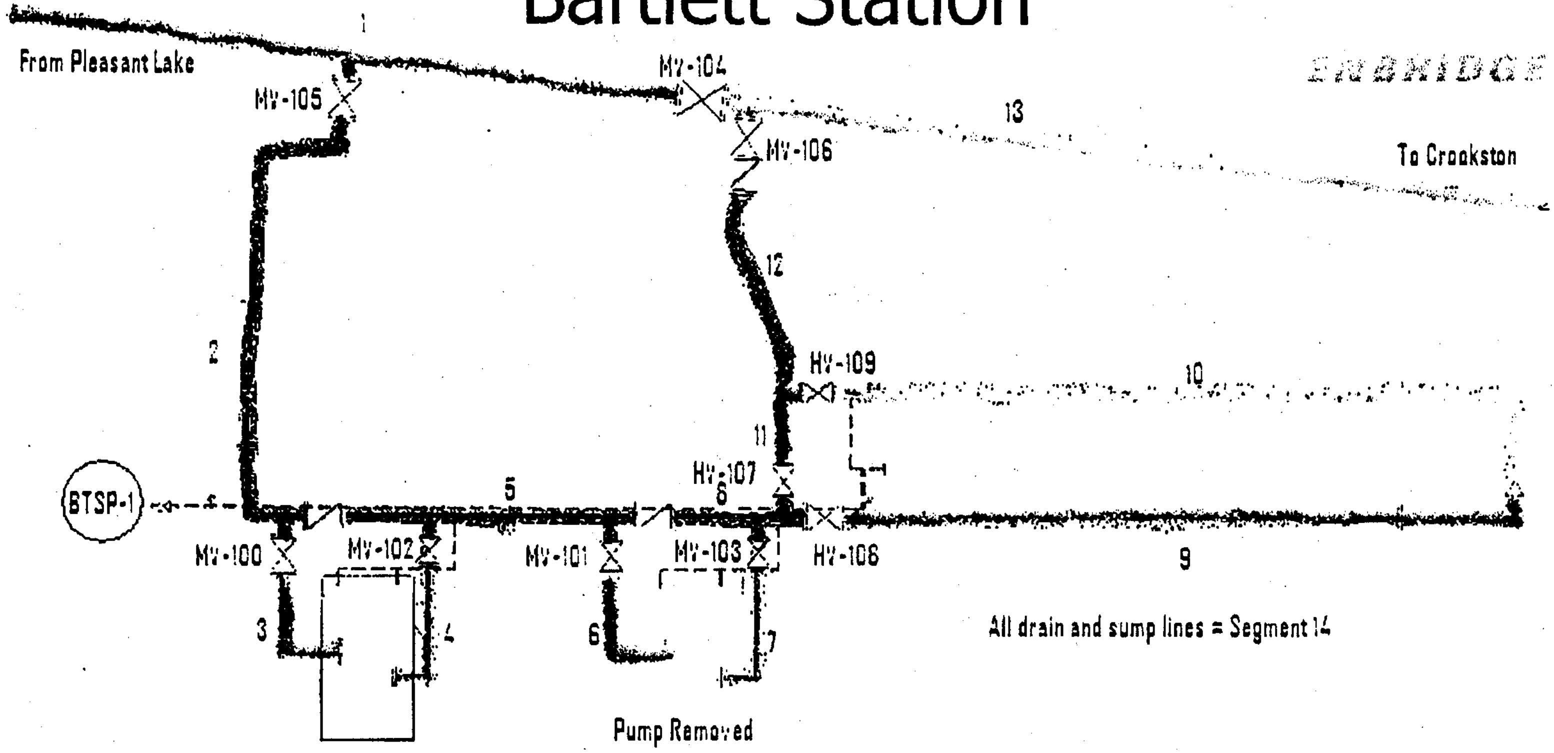
Size (SZ) = 5%

- **Category 5** - Piping between 36″ and 48″ in diameter
- **Category 4** - Piping between 24″ and 36″ in diameter
- **Category 3** - Piping between 12″ and 20″ in diameter
- **Category 2** - Piping between 4″ and 10″ in diameter
- **Category 1** - Piping less than 4″ in diameter

Physical Distribution (PD) = 5%

- **Category 5** - Completely underground
- **Category 4** - Combination of below and above grade (80/20)
- **Category 3** - Combination of below and above grade (50/50)
- **Category 2** - Combination of below and above grade (20/80)
- **Category 1** - Completely above ground

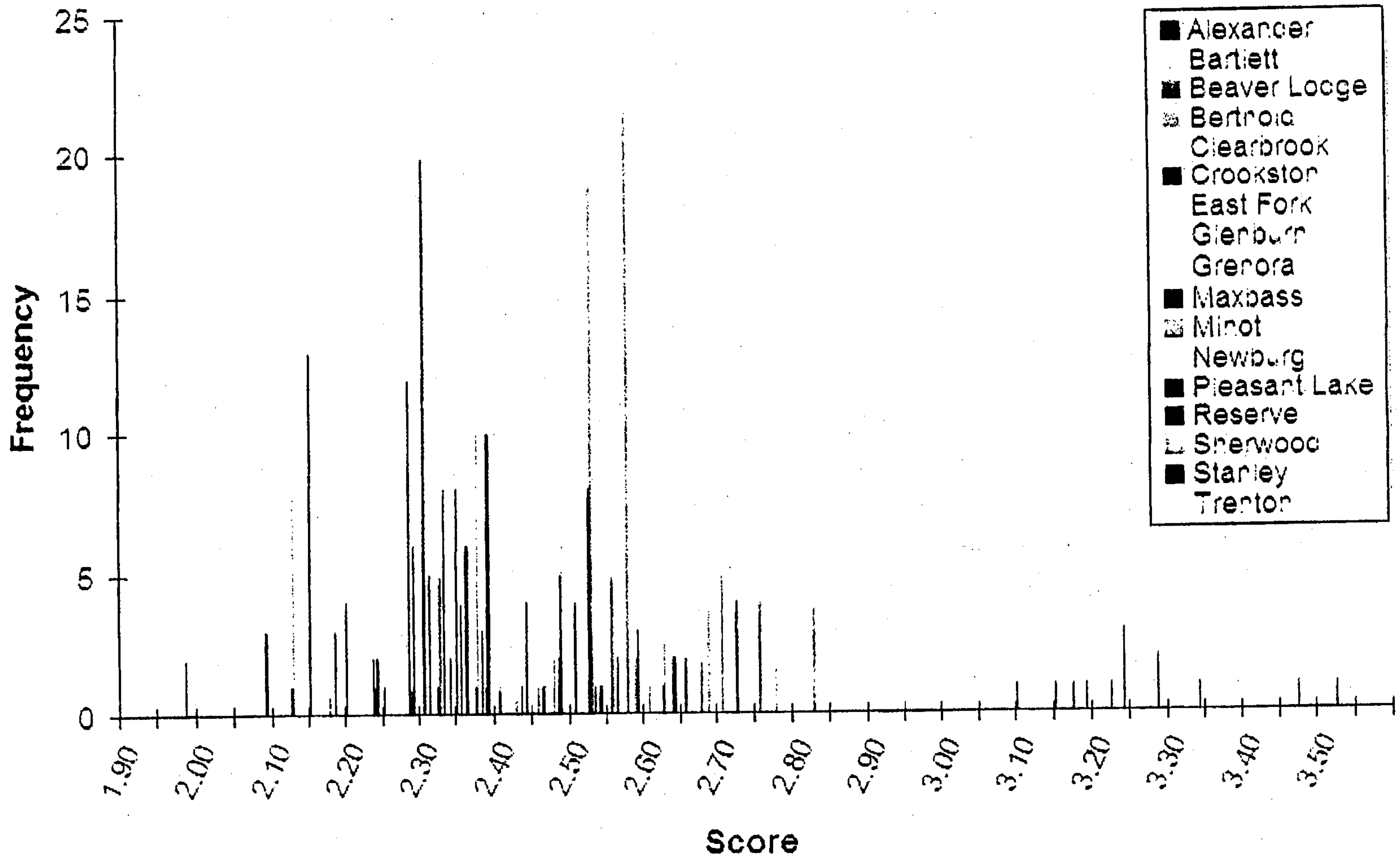
Bartlett Station



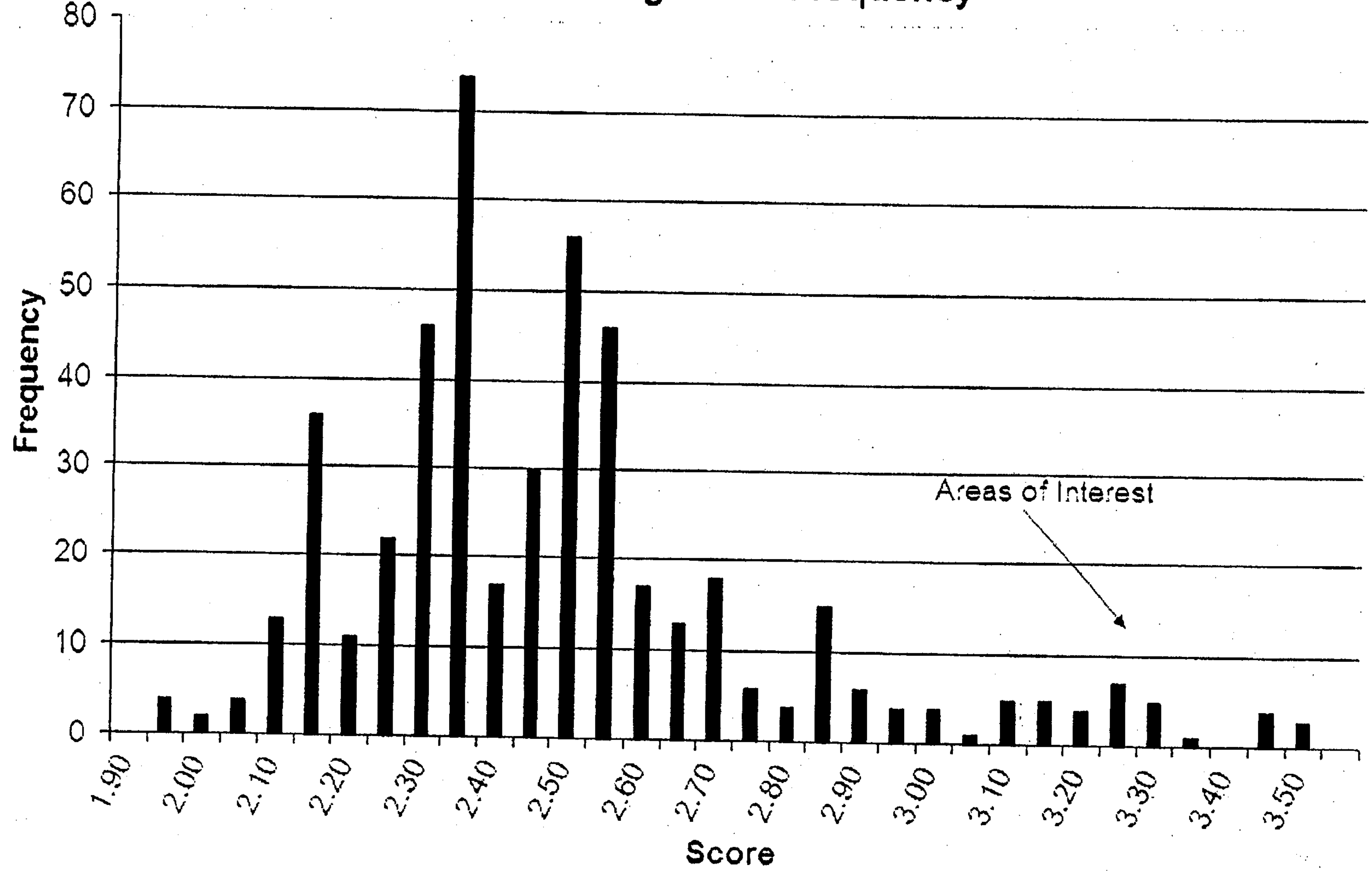
Segment #	From	To	PD - 5%	SZ(in)	SZ - 5%	LP - 15%	UG - 20%	AG - 10%	EV - 45%	SCORE
1	Pleasant Lake	Bartlett	1	16	3	5	1	3	2	2.35
2	MV105	MV100 Check Valve	5	12	3	5	1	3	2	2.55
3	MV100	MP1 Suction	2	10	2	5	1	3	2	2.35
4	MP1 Discharge	MV102	1	8	2	5	1	3	2	2.30
5	MP1 Check Valve MV102	MV101 Check Valve	1	12	3	5	1	3	2	2.35
6	MV101	MP2 Suction	2	10	2	5	5	3	2	3.15
7	MP2 Discharge	MV103	1	8	2	5	5	3	2	3.10
8	MP2 Check Valve	HV108 HV107	1	10	2	5	1	3	2	2.30
9	HV108	Segment 10	1	12	3	5	1	3	2	2.35
10	Segment 9	BTCV1 HV109	1	8	2	5	1	3	2	2.30
11	HV107 HV109	Segment 12	1	8	2	5	1	3	2	2.30
12	Segment 11	Check Valve MV106	5	12	3	5	1	3	2	2.55
13	MV104 MV106	Crookston	1	16	3	5	1	3	2	2.35
14	Sump Lines	Sump Lines	5	<4	1	5	1	3	2	2.45

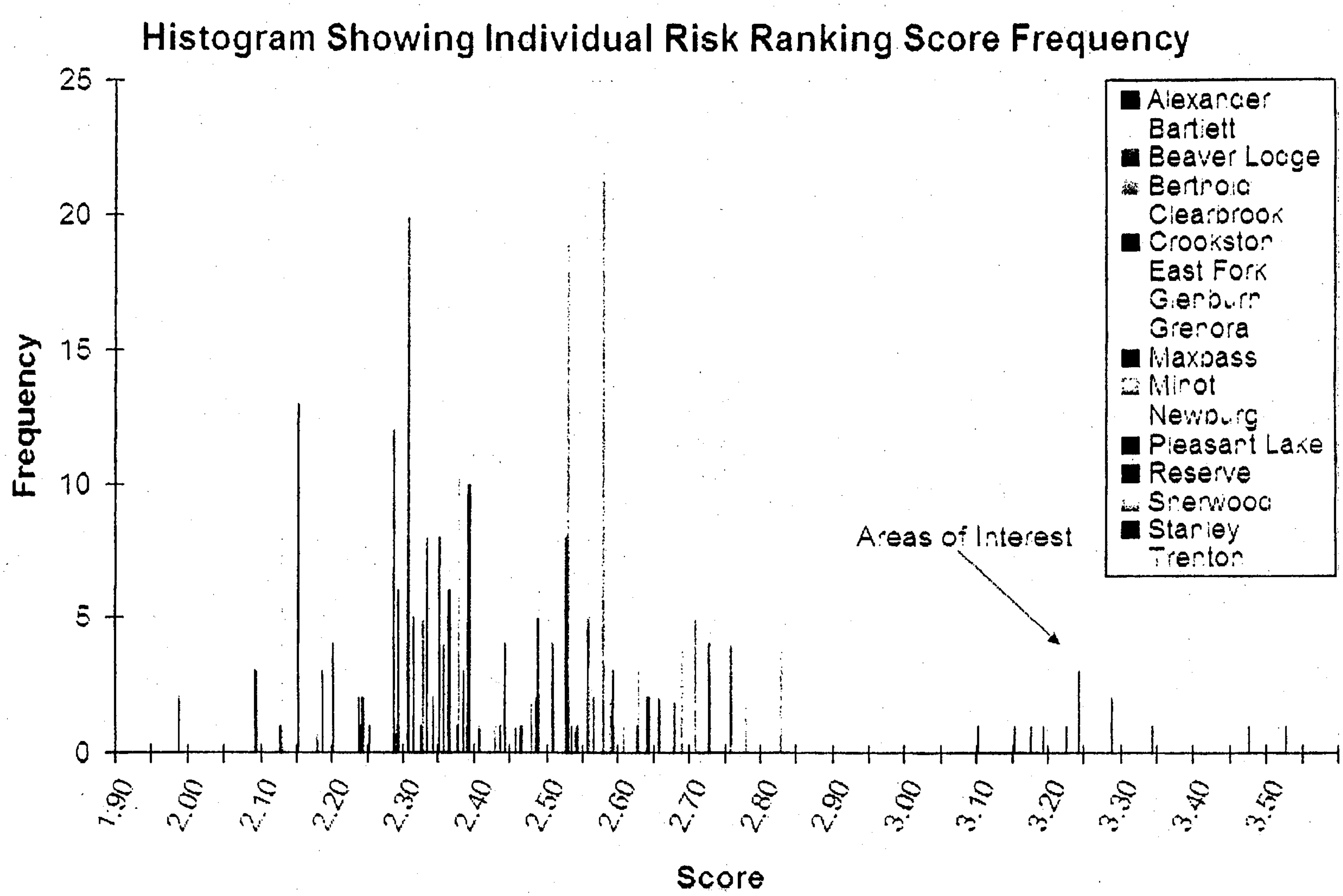
ENBRIDGE

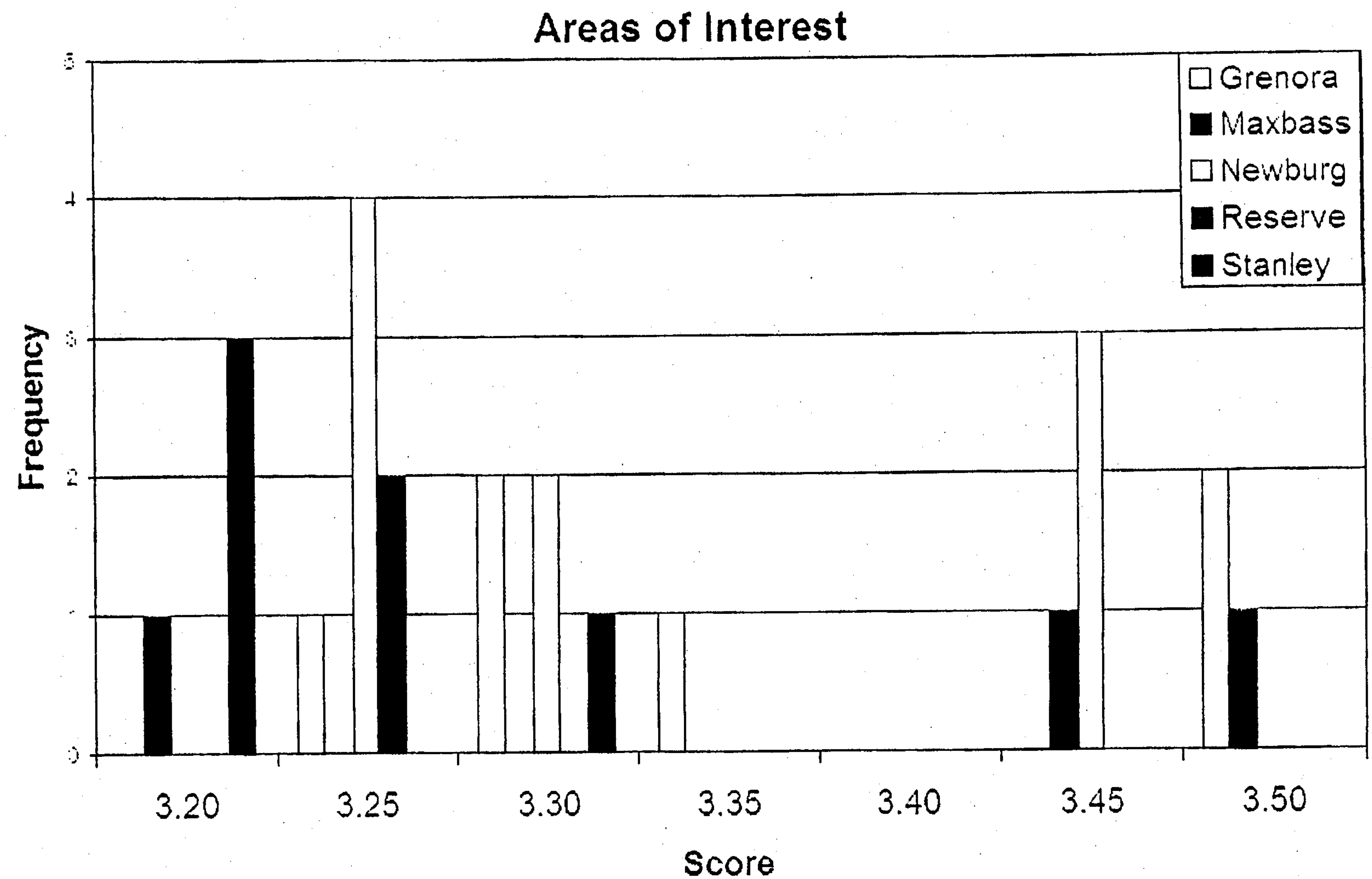
Histogram Showing Individual Risk Ranking Score Frequency



Risk Ranking Score Frequency




Histogram Showing Individual Risk Ranking Score Frequency
Frequency
25
20
15
10
5
0
1.90
2.00
2.10
2.20
2.30
2.40
2.50
2.60
2.70
2.80
2.90
3.00
3.10
3.20
3.30
3.40
3.50
Score
Areas of Interest
Alexander
Bartlett
Beaver Lodge
Bertrold
Clearbrook
Crookston
East Fork
Glenburn
Grenora
Maxbass
Minot
Newburg
Pleasant Lake
Reserve
Sherwood
Stanley
Trenton



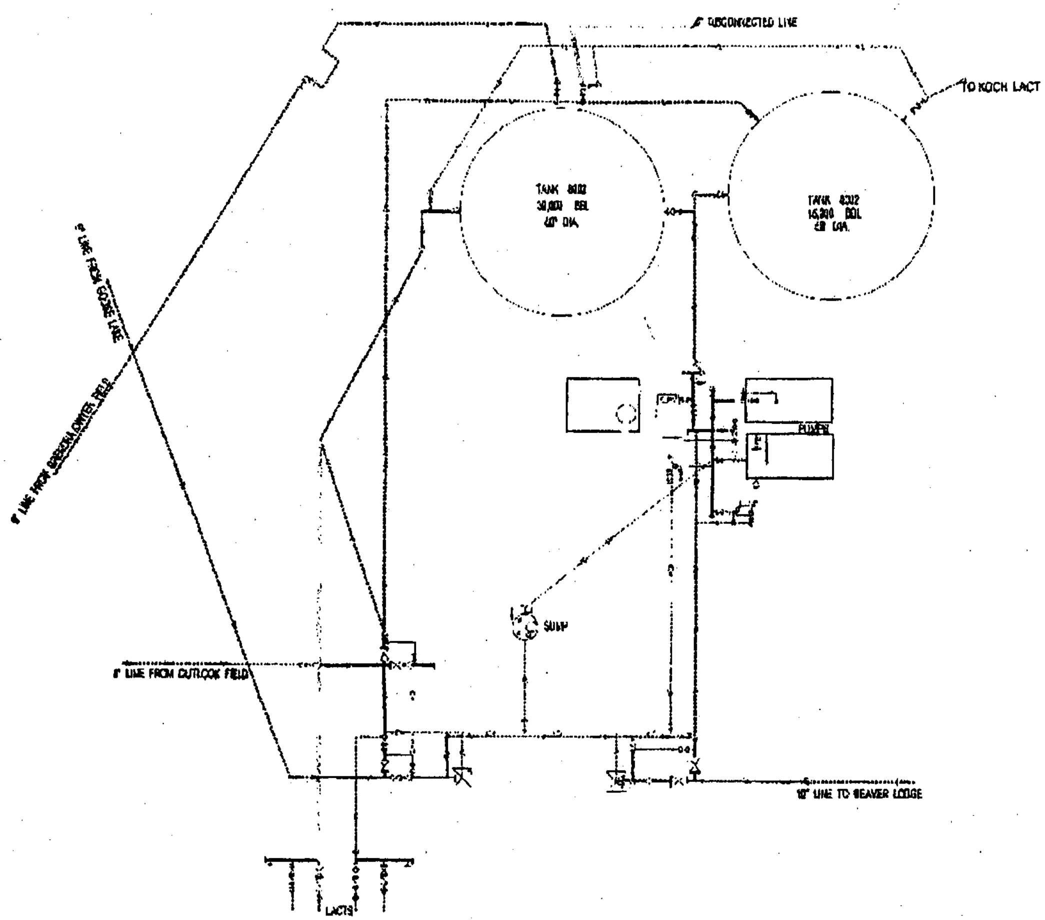
Areas of Interest
Grenora
Maxbass
Newburg
Reserve
Stanley
Frequency
0
2
4
3.20
3.25
3.30
3.35
3.40
3.45
3.50
Score

Focus Areas

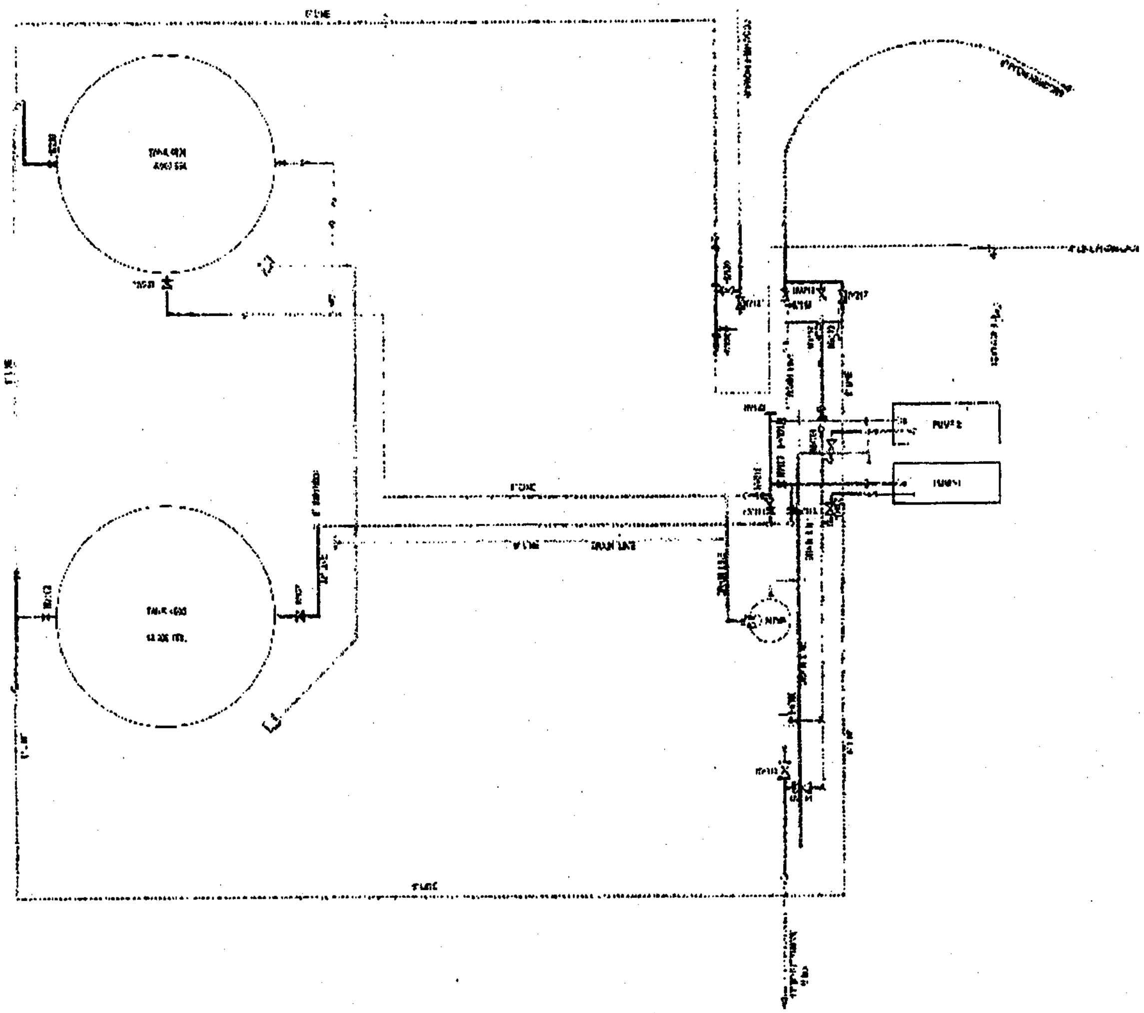
- The next few slides will show the highest ranked segments along with their location within each station.

Segments of Interest
Grenora

ENBRIDGE

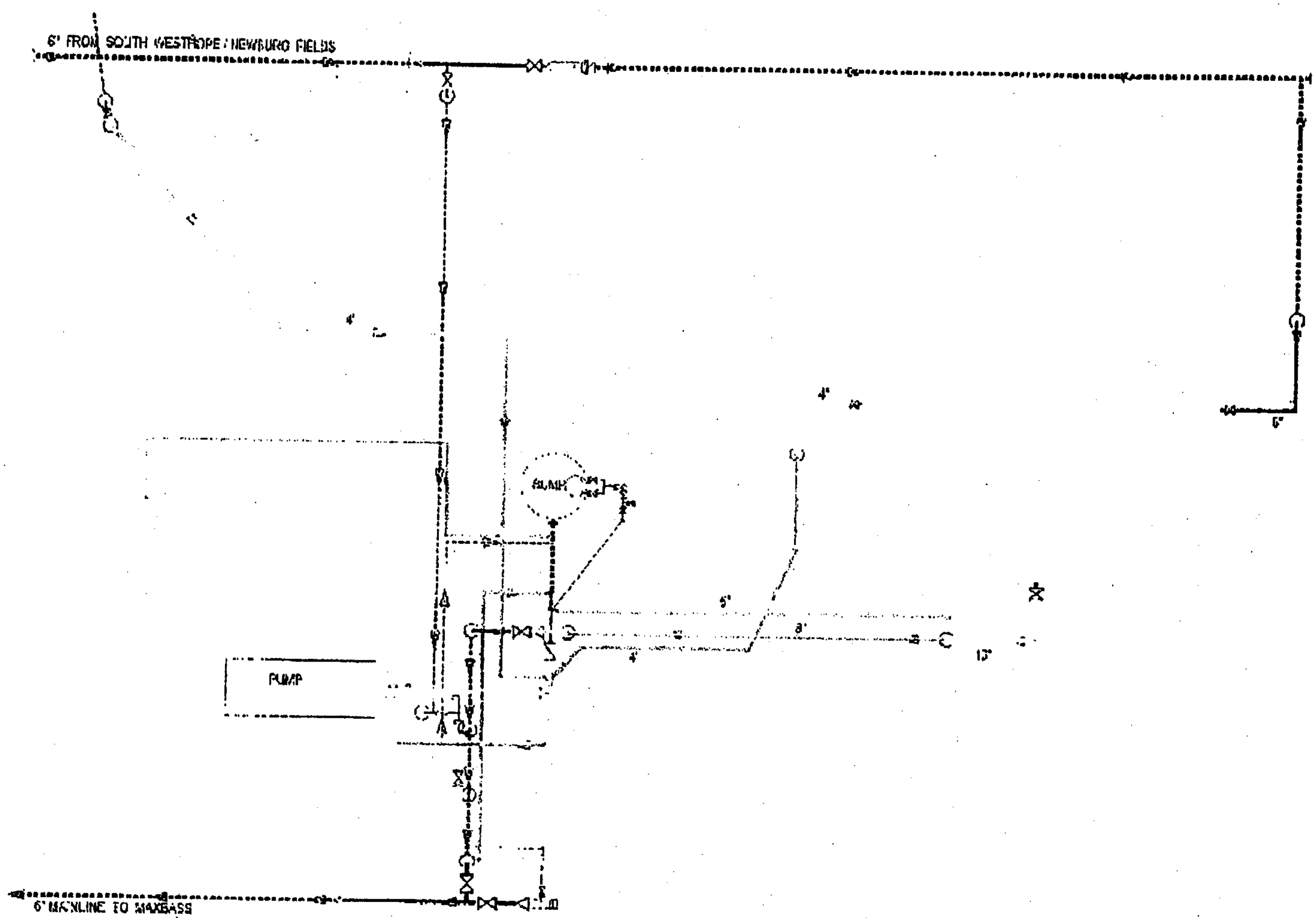


Segments of Interest
Maxbass

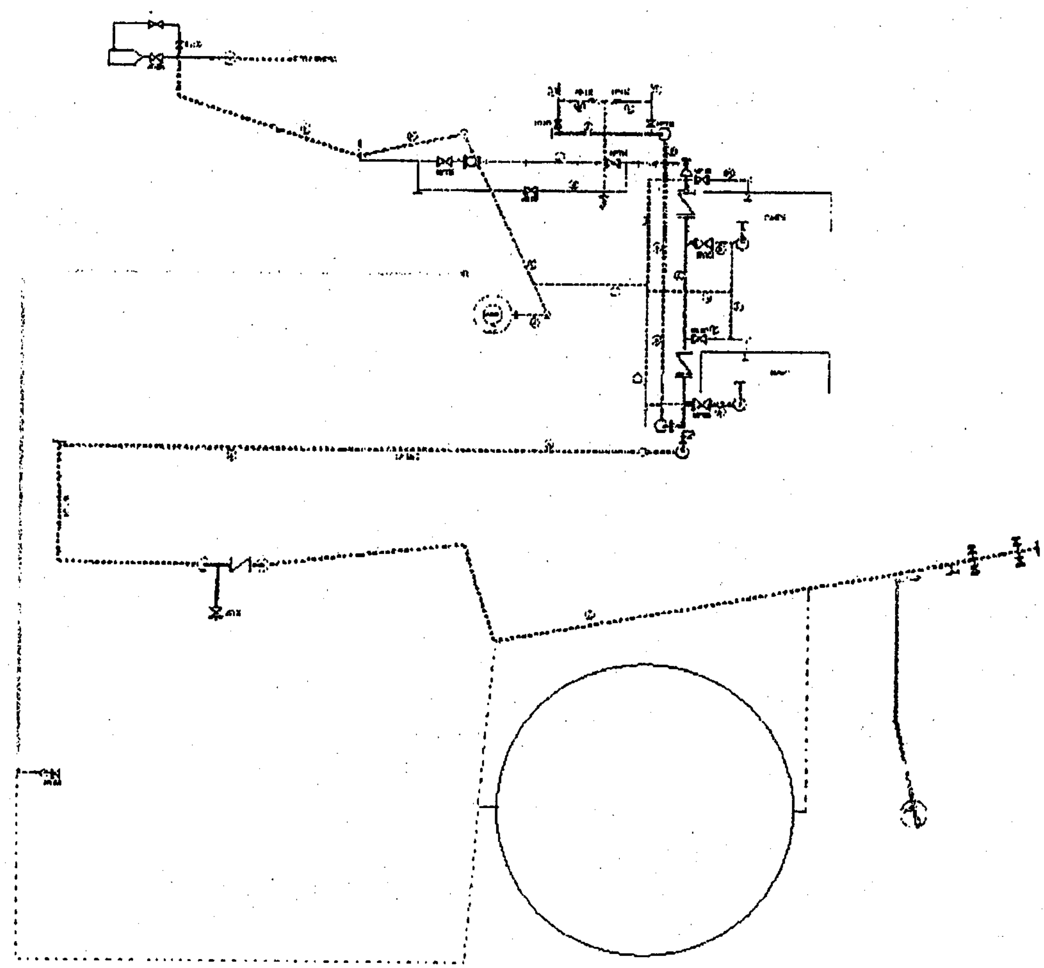


Segments of Interest
Newburg

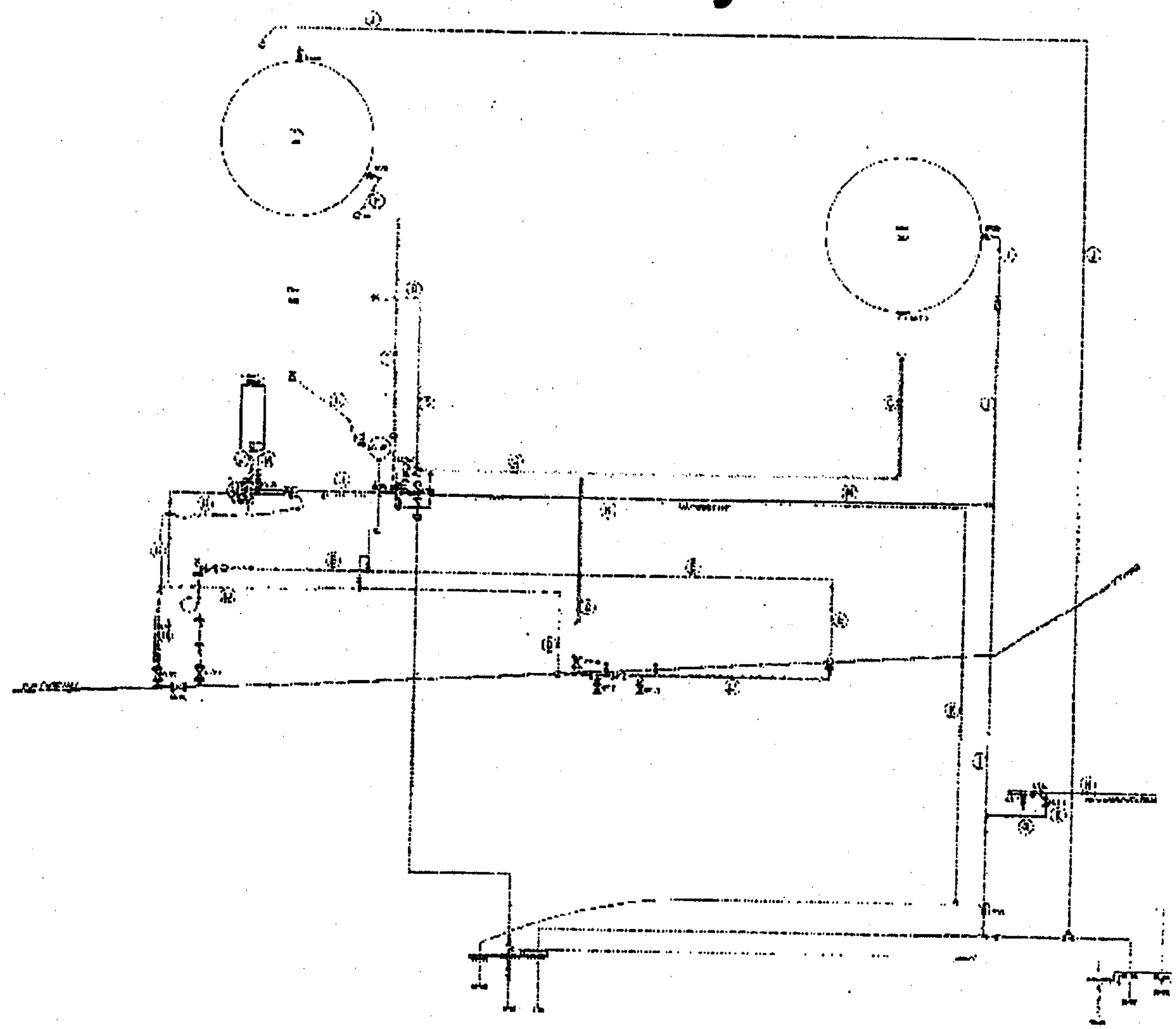
ENBRIDGE



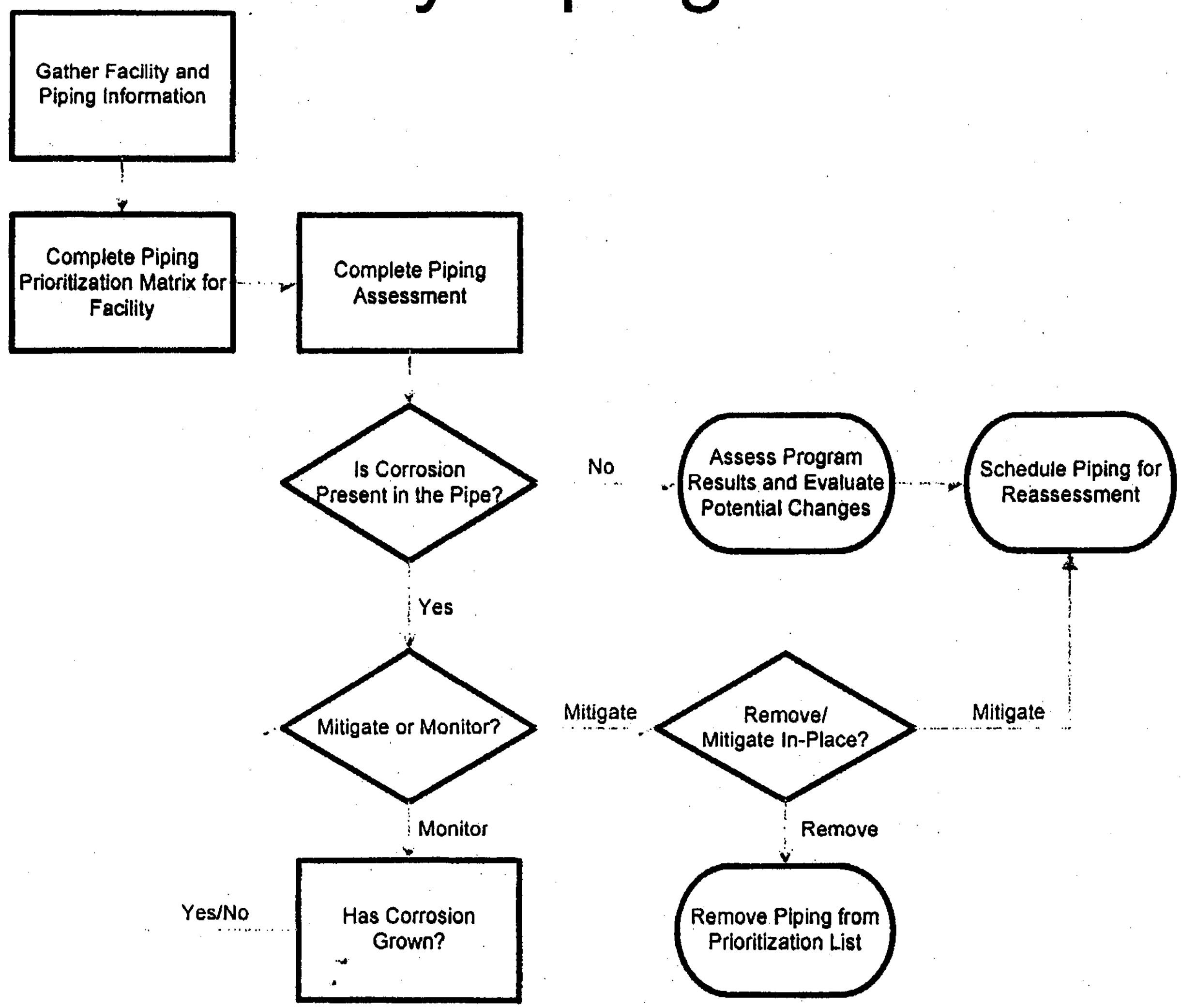
Segments of Interest
Reserve



Segments of Interest Stanley



Corrosion Management of Facility Piping Process



Questions?

Fw: Enbridge Pipelines LLC - North Dakota CPF 3-2007-5022

Tuesday, August 10, 2010
11:44 AM

Subject	**Fw: Enbridge Pipelines LLC - North Dakota CPF 3-2007-5022**
From	Theresa.Picton@enbridge.com
To	Barrett, David <PHMSA>; Shieh, Hans <PHMSA>
Sent	Wednesday, September 19, 2007 3:24 PM
Attachments	CPF3-2007-5022 Respo... Revision Request fo... Action Item Status table Facility Integrity A...

----- Forwarded by Theresa M Picton/LPL on 09/19/2007 03:22 PM -----

Theresa M Picton/LPL
09/19/2007
03:01 PM

To ivan.huntoon@.dot.gov

cc Matt Faith/US/Enbridge@LPL, Brian S Johnson/US/Enbridge@LPL, Jay A Johnson/LPL@LPL, Compliance and Risk Mgmt Filing@LPL, Compliance and Risk Mgmt Filing@LPL, david.barrett@.dot.gov, hans.shieh@dot

Subject Enbridge Pipelines LLC - North Dakota CPF 3-2007-5022

Dear Mr Huntoon:

Per your request, attached is the electronic version of Enbridge Pipelines LLC - North Dakota's response to CPF 3-2007-5022, and the three attachments listed in the letter. The hard copy was mailed to your office via Overnight Federal Express on September 18, 2007.

Please do not hesitate to contact Jay Johnson in the Superior Office at 715-394-1512 if you have any questions or require additional information.

Terri Picton
Compliance
715-394-1468

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880-5247
www.enbridgepartners.com

Jay Johnson
Senior Compliance Coordinator
Tel 715 394 1512
Fax 715 394 1500
jay.johnson@enbridge.com

September 18, 2007

Ivan A Huntoon
Central Region – PHMSA
901 Locust Street, Room 462
Kansas City MO 64106-2641

RE: CPF - 3 - 2007 - 5022

Dear Mr. Huntoon:

Pursuant to the above mentioned Pipeline and Hazardous Materials Safety Administration (PHMSA) Notice of Probable Violation and Proposed Civil Penalty, Enbridge Pipelines North Dakota LLC (EPND) is submitting written explanations, information and other materials regarding the merits of the allegations. EPND is seeking mitigation or elimination of the proposed civil penalty as outlined in the Response Options for Pipeline Operators in Compliance Proceedings.

EPND's request to mitigate the proposed civil penalty is based on:

1. EPND's effective response to incident and cleanup,
2. EPND's prompt and effective mitigative and corrective actions,
3. Minimal impact to Public Safety and the Environment,
4. EPND's cooperative response and open relationship with PHMSA,
5. EPND's excellent operational history.

As detailed in the post mortem template, (previously submitted) EPND responded quickly and effectively to isolate and limit the release. Ensuing containment, all free product was recovered and all impacted soil was properly disposed. The release was totally contained on EPND property and therefore did not pose any threats to public safety. However, ground water monitoring wells were installed in the vicinity to ensure no product escaped the containment area.

Following the incident, a committee comprised of subject matter experts from Operations, Engineering and Management developed a list of corrective actions and lessons learned utilizing the Det Norske Veritas Systematic Cause Analysis Technique. Both root cause and non-critical improvements were identified. From this a revision to the Operating and Maintenance Manual was issued which was immediately reviewed by all engineering and field personnel. The Incident Report was also circulated for review. In addition, EPND has completed a Facility Integrity Risk Assessment on all station facilities and has focused efforts to address dead leg, idle and low flow piping.

During the course of investigating this incident, EPND kept Central Region PHMSA updated via phone and electronic communications such as; photographs, thermal calculations and the root cause analysis. It is our policy to determine the cause and communicate the corrective measures within the Enbridge companies to avert any possible reoccurrences. As part of our investigations, we value the comments and concerns expressed by PHMSA and take them all into consideration.

Materials attached for your review are:

- Operating and Maintenance Procedures Manual revision
- Incident Investigation corrective action status list
- Facility Integrity Assessment Program

In conclusion, EPND is committed to operating in full regulatory compliance and has an excellent record of working jointly with PHMSA to ensure pipeline safety. Therefore, we respectfully request that PHMSA review our request to mitigate or eliminate the proposed civil penalties. If you have any questions or require additional information please contact Jay Johnson in our Superior office at 715/394-1512.

Sincerely,

Steve Irving
Director, System Integrity and Compliance

cc: Janet Holder
Brian Johnson
Jay Johnson
Terry McGill
Mark Willoughby

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

1200 New Jersey Ave., SE
Washington, DC 20590

JUN 02 2009

Mr. Brian Johnson
North Dakota Manager
Enbridge Pipelines LLC-North Dakota
1100 Louisiana, Suite 3200
Houston, TX 77002

Re: CPF 3-2007-5022

Dear Mr. Johnson:

Enclosed is the Final Order issued in the above-referenced case. It makes a finding of violation and assesses a civil penalty of $105,000. The penalty payment terms are set forth in the Final Order. This enforcement action closes automatically upon payment. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

fr Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Ivan Huntoon, Director, Central Region, PHMSA

CERTIFIED MAIL – RETURN RECEIPT REQUESTED **[7005 1160 0001 0046 9525]**

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880-5247
www.enbridgepartners.com

Jay Johnson
Senior Compliance Coordinator
Tel 715 394 1512
Fax 715 394 1500
jay.johnson@enbridge.com

September 18, 2007

Ivan A Huntoon
Central Region – PHMSA
901 Locust Street, Room 462
Kansas City MO 64106-2641

RE: CPF - 3 - 2007 - 5022

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Sincerely,

Steve Irving
Director, System Integrity and Compliance

cc: Janet Holder
Brian Johnson
Jay Johnson
Terry McGill
Mark Willoughby

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of **Enbridge Pipelines LLC-** **North Dakota,** **Respondent.**	**CPF No. 3-2007-5022**

FINAL ORDER

Pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety (OPS) conducted an investigation of an incident involving a spill of approximately 9,030 gallons of crude oil from a pipeline operated by Enbridge Pipelines LLC-North Dakota (Enbridge or Respondent) near Stanley, North Dakota. Enbridge operates a 558-mile pipeline system that delivers crude oil from northwest North Dakota to Clearbrook, Minnesota.

The accident occurred on January 25, 2007, at the company's Stanley Pump Station, and involved a section of crude oil piping that had been temporarily idled during a construction project.[1] As a result of the subsequent OPS investigation, the Director, Central Region, OPS (Director), issued to Respondent, by letter dated August 21, 2007, a Notice of Probable Violation and Proposed Civil Penalty (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had violated 49 C.F.R. § 195.406 and proposed assessing a civil penalty of $105,000 for the alleged violation.

Respondent responded to the Notice by letter dated September 18, 2007 (Response). Enbridge did not contest the allegation of violation but offered information and explanations regarding the proposed penalty and requested that the proposed civil penalty be reduced or eliminated. Respondent did not request a hearing and therefore has waived its right to one.

[1] The spill was contained on site and did not migrate to any water sources or underground wells. *See,* OPS Violation Report, at 3.

FINDING OF VIOLATION

In its Response, Enbridge did not contest the allegation in the Notice that it violated 49 C.F.R. Part 195, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.406(b), which in relevant part states:

> **§ 195.406 Maximum operating pressure.**
> (a) . . .
> (b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

The Notice alleged that Respondent violated § 195.406(b) by permitting the pressure in its pipeline during surges or other variations from normal operations to exceed 110 percent of the line's maximum operating pressure.[2] Specifically, the Notice alleged that Enbridge allowed a line at the Stanley Pump Station to exceed 110% of the line's maximum operating pressure by failing to provide a pressure relief device on an isolated section. As part of the construction project that began in November, 2006, the company had isolated the section of line by installing a blind flange on one end and a one-way check valve on the other. On January 25, 2007, the outside temperature increased significantly, thereby causing the pressure in the isolated line to exceed 100% of its specified minimum yield strength (1470 psig) and the pipe to fail.

Respondent did not contest the allegation of violation. Accordingly, upon consideration of all of the evidence, I find that Respondent violated 49 C.F.R. § 195.406(b), as more fully described in the Notice.

This finding of violation will be considered a prior offense in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to an administrative civil penalty not to exceed $100,000 per violation for each day of the violation, up to a maximum of $1,000,000 for any related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: the nature, circumstances, and gravity of the violation,

---

2 The maximum operating pressure of the line was 980 psig. *See,* Violation Report, at 2.

including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; the Respondent's ability to pay the penalty and any effect that the penalty may have on its ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require.

The Notice proposed a total civil penalty of $105,000 for violation of § 195.406(b). Providing adequate pressure control is a key part of maintaining pipeline safety and protecting the environment. Pipeline operators are obligated to ensure that the maximum operating pressure of their lines is not exceeded because damage and failures can result, as occurred in this case. In its Response, Enbridge requested a reduction or elimination of the civil penalty based upon: (1) the company's prompt response to the accident, including cleanup; (2) the corrective actions it initiated after the accident to prevent similar accidents; (3) the minimal impact that the accident had on public safety and the environment; (4) its cooperative response to the OPS investigation; and (5) its compliance history.

The corrective actions to which Respondent refers, however, were taken after the accident had already occurred. It is true that PHMSA considers any "good faith" efforts in calculating and assessing civil penalties, but only for those actions that an operator has taken in a reasonable attempt to achieve compliance. Once an accident has occurred or a violation has been discovered, PHMSA would expect any prudent and responsible operator to cooperate in preventing another accident or violation.

With respect to Respondent's contention that the release's impacts on public safety and the environment were minimal, I would note that virtually any release of hazardous liquids from a pipeline can result in serious risk of injury. In this case, the pipeline ruptured and released approximately 9,030 gallons of crude oil into the environment. Respondent is fortunate that no greater environmental harm or physical injury occurred. The record indicates that at least one Enbridge employee was on site at the time of the incident and therefore could have been injured.

There is no evidence to suggest that Respondent lacks the ability to pay the penalty or that its imposition could affect the company's ability to continue doing business. Respondent has presented no information that would warrant a reduction in the civil penalty proposed in the Notice. Respondent's past compliance history was taken into account in formulating the initial proposed penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $105,000 for violating §195.406(b).

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 269039, Oklahoma City, OK 73125; (405) 954-8893.

Under 49 C.F.R. § 190.215, Respondent has the right to submit a petition for reconsideration of this Final Order. Should Respondent elect to do so, the petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of a petition automatically stays the payment of any civil penalty assessed. However if Respondent submits payment for the civil penalty, the Final Order becomes the final administrative decision and the right to petition for reconsideration is waived. The terms and conditions of this Final Order shall be effective upon receipt.

for Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

JUN 02 2009

Date Issued

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 15, 2007

Mr. Terry McGill
President
Enbridge Energy, Limited Partners
1100 Louisiana
Suite 3300
Houston, TX 77002

CPF 3-2007-5031W

Dear Mr. McGill:

On August 6-10, 2007 and September 24-28, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Minnesota Office of Pipeline Safety (MN-OPS) pursuant to Chapter 601 of 49 United States Code inspected your records in Superior, WI and your facilities in North Dakota and Minnesota.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. **§195.49 Annual report**

   Beginning no later than June 15, 2005, each operator must annually complete and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Operators are encouraged, but not required, to file an annual report by June 15, 2004, for calendar year 2003.

Enbridge did not accurately report the mileage of their highly volatile liquid (HVL) line for 2005 and 2006.

Review of the 2005 annual report found that Enbridge was reporting 190 miles as the total mileage for their HVL systems. This 190 miles was from Clearbrook to Superior. However, the 20" line from the Canadian border to Clearbrook predominantly transports HVL's and should have been reported as an HVL line as well.

2. **§195.410 Line markers.**

   (c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.

   Enbridge did not have any line markers at the above ground exposure located at the Necktie River crossing.

   The exposure at the Necktie River Crossing was brought to the attention of the MN-OPS by the MN Department of Pollution Control during the records review. When the exposure was visited during the subsequent field evaluation, it was noted that there were no line markers at the exposure, nor were there any within ½ mile of this exposure.

3. **§195.573 What must I do to monitor external corrosion control?**

   a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

   (1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

   Enbridge personnel did not take annual cathodic protection readings in 2005 and 2006 at one test point in North Dakota and two test points in Minnesota.

   The annual cathodic protection records reviewed found that the test stations at MP 831.065 in North Dakota and MPs 1035.483 and 1043.064 did not have readings taken in 2005 and 2006. Your personnel were unable to explain why the readings were not taken.

4. **§195.583 What must I do to monitor atmospheric corrosion control?**

   (a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months**

Enbridge personnel have not conducted an atmospheric inspection of the above ground pipeline facilities located MP 797, MP 829, and the Necktie River.

While reviewing the atmospheric corrosion survey books, it was noted that the exposures at MP 797 and 829 did not have an evaluation. As indicated earlier, during the records inspection, a picture of an exposure at the Necktie River was sent to the MN-OPS by the MN Department of Pollution Control. Further investigation found that this exposure also did not have an evaluation done.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Failure to do so will result in Enbridge Energy, Limited Partners being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 3-2007-5031W**. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

LETTER OF CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 15, 2007

Mr. Terry McGill
President
Enbridge Energy, Limited Partners
1100 Louisiana
Suite 3300
Houston, TX 77002

CPF 3-2007-5032C

Dear Mr. McGill:

On August 6-10, 2007 and September 24-28, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Minnesota Office of Pipeline Safety (MN-OPS) pursuant to Chapter 601 of 49 United States Code inspected your records in Superior, WI and your facilities in North Dakota and Minnesota.

As a result of the inspection, the following item was identified as a concern:

Review of the Abnormal Operating Conditions (AOC) database found one concern. The AOC database indicates that the date of the AOC was when it was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. As a result, it doesn't appear that provisions have been established to allow for trending or evaluation of the AOC's based on occurred date and time.

We hope you will consider this area of concern as an opportunity to improve your existing pipeline safety program. If we can answer any questions or be of any help, please call us at 816-329-3800.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 3-2007-5032C.** Be advised that all material you submit in response to this letter is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 21, 2010

Mr. Terry McGill, President
Enbridge Energy Partners, L.P.
1100 Louisiana, Suite 3300
Houston, Texas 77002

CPF 3-2010-5002W

Dear Mr. McGill:

On October 6-8, 2008, October 28, 2008, and January 21-22, 2009, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your facilities associated with the Griffith Unit in Griffith, Indiana, and surrounding locations.

As a result of the inspection, it appears that you have committed a probable violation of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. **195.579 What must I do to mitigate internal corrosion?**

   (b) Inhibitors. If you use corrosion inhibitors to mitigate internal corrosion, you must--

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;
(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and
(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7 1/2 months.

Internal corrosion monitoring was discontinued on the five hydrogen permeation monitors (Beta Foils) installed on Line 6B. Two manually-interrogated monitors were discontinued in May 2006. One remotely-interrogated monitor was discontinued in January 2006, and the other two remotely-interrogated monitors were discontinued in October 2007. Enbridge representatives stated the monitoring was discontinued due to "communication/instrumentation problems."

Enbridge is in the process of implementing an alternative method of internal corrosion monitoring on Line 6B utilizing a technology referred to as Electrical Resistance Tomography (FSM-IT), however, it is not expected to be implemented on Line 6B until sometime during the first half of 2010. In the interim, Enbridge provided the following information as demonstration that the internal corrosion threat is being properly managed:

- a comprehensive report related to the internal corrosion mitigation and monitoring program for their heavy oil pipeline system
- repair sleeve installations (which require circumferential non-destructive testing)
- inspection of the Line 6B Pig Sending Trap at Griffith Station (which included ultrasonic inspection of the trap floor between the 5:00 and 7:00 positions)
- detailed pipe examinations at in-line inspection indications
- records for a weight loss coupon at the Stockbridge Pumping Station (Line 17), which sees only fluid flow from Line 6B

The information provided does not demonstrate compliance with the above regulation. Line 6B has been subject to a batch chemical treatment program to inhibit internal corrosion for several years. As required by 195.579(b), Line 6B must have coupons or other monitoring equipment to determine the effectiveness of the inhibitor program, and the coupons or other monitoring equipment must be examined at least twice each calendar year, at intervals not to exceed 7-1/2 months. PHMSA acknowledges the positive steps being taken to improve Enbridge's internal corrosion mitigation and monitoring program. However, the transition from one technology to another must be implemented in a manner that ensures continued compliance with the regulations.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item identified in this letter. Failure to do so will result in Enbridge being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 3-2010-5002W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880-5247
www.enbridgepartners.com

Jay Johnson
Senior Compliance Coordinator
Tel 715 394 1512
Fax 715 394 1500
jay.johnson@enbridge.com

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April 10, 2007

Rodrick M Seeley
Director, Southwest Region
Pipeline and Hazardous Materials
Safety Administration
8701 South Gessner, Suite 1110
Houston TX 77074

RECEIVED APR 12 2007

RE: CPF 4-2007-5006M

Dear Mr. Seeley:

In response to your letter dated March 1, 2007 regarding PHMSA, NY PSC & MNOPS's Team Inspection of Enbridge's procedures for operations and maintenance in May, 2006, Enbridge does not disagree with the observations and has taken steps to amend the applicable procedures, some of which have already been submitted electronically to lead inspector Buddy Sheets in 2006.

Enbridge is continuing to work on the other outstanding items which include seven issues relating to cathodic protection. We are currently reviewing the new NACE Operator Qualification Program to verify that their written assessments will meet our needs for OQ Training and at the same time provide us with industry standard procedures to reference in our O&MP Manuals.

It is our goal to complete the revisions identified during the inspection by the end of the Second Quarter. If requested, we could send each revision as it is completed but feel it would be more convenient to do them in a package submission.

If you have any questions or comments, please let me know. We appreciate the opportunity to work with PHMSA to improve our operating and maintenance procedures.

Sincerely,

Jay Johnson
Senior Compliance Coordinator

cc: Ivan Huntoon
Buddy Sheets
Steve Irving
Terrance McGill

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jay.johnson@enbridge.com

ENBRIDGE™

October 31, 2007

Rodrick M Seley
Director, Southwest Region
Pipeline and Hazardous Materials
Safety Administration
8701 South Gessner, Suite 1110
Houston TX 77074

RE: CPF 4-2007-5006M

Dear Mr Seeley:

In response to the Notice of Amendment dated March 1, 2007, we offer the following comments:

Item A
Enbridge Energy procedures did not contain a formal procedure to periodically review the work of personnel to determine the effectiveness of the O&M procedures relating to the pipeline safety regulations. Enbridge needs to amend their procedures to include reviewing the work of personnel to determine the effectiveness of the O&M procedures relating to the pipeline safety regulations.
Response: See Attachment "Item A"

Item B
Enbridge Energy procedures did not clearly state that employees are trained on an ongoing basis to recognize safety related conditions. Enbridge needs to amend their procedures to state that employees are trained on an ongoing basis to recognize safety related conditions.
Response: See Attachment "Item B"

Item C
Enbridge Energy procedures did not clearly state that supervisors are included in the annual training. Enbridge needs to amend their procedures to state that supervisors are included in annual training.
Response: See Attachment "Item C"

Item D
Enbridge Energy procedures did not fully describe the actual description of two-way communication methods and procedures (e.g. cell phones, landline to radio towers, etc) between the Edmonton Control Center and the scene of abnormal operations or emergencies. Enbridge needs to amend their procedures to describe the actual description of two-way communication methods between the Edmonton Control Center and the scene of abnormal operations or emergencies.
Response:
See Attachment "Item D" Part 1 and Part 2 (Book 1, Forward, page 2 and 3 of 4 which existed but we were unable to demonstrate during the audit).

Item E
Enbridge Energy procedures did not fully describe the practice of placing a sufficient number of line markers along the right-of-way. Enbridge needs to amend their procedures to describe the practice of placing a sufficient number of line markers along the right-of-way.
Response: See Attachment "Item E"

Item F
Enbridge Energy procedures did not address how the capacity of the relief valve is determined to be adequate. Flow capacity needs to be verified in light of changing operational parameters since the relief valves were originally installed. Enbridge needs to amend their procedures to describe how the capacity of the relief valve is determined to be adequate. Enbridge procedures need to take into account changing operational parameters for relief valves since they were originally installed.
Response: See Attachment "Item F" Part 1 and 2

Item G
Enbridge Energy procedures did not fully describe the installation of overfill protection per API RP 2350 on breakout tanks that are significantly altered. Enbridge needs to amend their procedures to describe the installation of overfill protection per API RP 2350 on breakout tanks that are significantly altered.
Response: See Attachment "Item G"

Item H
Enbridge Energy procedures did not describe how the list of excavators is kept current.
Response: See Attachment "Item H"

Item I
Enbridge Energy procedures do not describe how one-call notifications are handled once notifications are received. Enbridge needs to amend their procedures to describe how one-call notifications are handled once notifications are received.
Response: See Attachment "Item I"

Item J
Enbridge Energy procedures were not clear on the requirement for supervisors to maintain a thorough knowledge of corrosion control procedures, nor did the procedures state how supervisor knowledge of corrosion control was to be verified. Enbridge needs to amend their procedures need to be clearly state the requirement for supervisors to maintain a thorough knowledge of corrosion control procedures and these procedures need to state how supervisor knowledge of corrosion control is verified.
Response: See Attachment "Item J"

Item K
Enbridge Energy procedures were not clear on how test leads are maintained. Enbridge needs to amend their procedures to state how test leads are maintained.
Response: See Attachment "Item K"

Item L
Enbridge procedures did not address IR drop considerations for the (-850 mV) on-criteria. Enbridge needs to amend their procedures to address IR drop considerations.
Response: See Attachment "Item L"

Item M
Enbridge Energy procedures did not describe in what circumstances close interval surveys are completed. Enbridge needs to amend their procedures to describe in what circumstances close interval surveys are completed.
Response: See Attachment "Item M"

Item N
Enbridge Energy procedures need to ensure hat cathodic protection system maintenance and testing of breakout tanks is in conformance with API 651. Enbridge needs to amend their procedures to ensure that cathodic protection system maintenance and testing of breakout tanks is in conformance with API 651.
Response: See Attachment "Item N"

Item O
Enbridge Energy procedures did not describe the timing for correction of deficiencies found. Enbridge needs to amend their procedures to describe the timing for corrections f deficiencies found.
Response: See Attachment "Item O"

Item P
Enbridge Energy procedures need detailed descriptions of electrical isolation installations, inspections, tests, safeguards and when they are required. Enbridge needs to amend their procedures to provide detailed descriptions of electrical isolation installations, inspections, test, safe guards and when they are required.
Response: See Attachment "Item P"

Item Q
Enbridge Energy procedures do not specify the retention time for atmospheric corrosion inspections. Enbridge needs to amend their procedures need to specify the retention time for atmospheric corrosion inspections.
Response: See Attachment "Item Q"

I trust these explanations have addressed all concerns expressed during the audit. Should you have any further questions, please feel free to contact me.

Sincerely,

Jay Johnson

Enclosure

cc: Steve Irving
Mark Willoughby

ITEM A

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Revision Request Form

Submitter: Jay A Johnson		Date: 10/30/07
Select Book:	☒ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Book 1, Tab 5	Subject Title: Reviewing the Effectiveness of Operational Procedures	
Subject Revision Date (printed on bottom of page): Whenever the revision pack goes out.		

Existing Wording:

There is no existing wording in the Main Line O & MP Series. The procedure below comes from the Enbridge Gathering Systems O & MP Manual and has been approved by Region Management.

Proposed Wording:

Reviewing the Effectiveness of Operational Procedures
During the course of the year Enbridge completes various measures to ensure the work done by operating personnel is effective utilizing the procedures found in this manual, in Maximo and in the Operators Qualification (OQ) program.

They may include:

- Annual manual review with select operating personnel
- Manual revision process and Revision Request form
- Incentive based safety program which promotes procedure revisions
- All manual revisions are reviewed at local safety meetings to communicate changes and solicit additional comments and/or changes.
- Pipe Line Maintenance Technical committee meets quarterly to review and address on-going procedural problems.
- Maintain Pipeline Facilities team is available for addressing procedural issues.
- Quarterly Operations meetings/Annual Gathering Systems meetings
- Annual ride-a-longs with personnel to discuss issues/concerns regarding job tasks
- Monthly safety meetings at local offices include operations discussions
- In addition to the tri-annual required review of OQ tasks, new employees are operator qualified in "off-cycle" years, thus nearly annual review of OQ procedures.
- Table top exercises

Documentation of the above mentioned will be maintained by the Departments and/or on the appropriate databases.

Reason for Change:

Compliance requirement;

195.402 (C) (13). Periodically reviewing the work done by operator to determine the effectiveness of the procedures used in normal operations and maintenance and taking corrective action where deficiencies are found.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM B

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	**Effective Date: August 01, 2006**

Revision Request Form

Submitter: Jay A Johnson		**Date: 10/30/07**
Select Book:	☒ **Book 1: General Reference** ☐ **Book 2: Safety** ☐ **Book 3: Pipeline Facilities**	☐ **Book 4: Welding** ☐ **Book 5: Petroleum Quality & Measurement** ☐ **Book 7: Emergency Response**
Subject Number: Book 1, Tab 5	**Subject Title: Recognizing Safety Related Condition**	
Subject Revision Date (printed on bottom of page): Whenever the revision package goes out.		

Existing Wording:

There is no existing wording to describe the process that the Compliance Department is completing on an annual basis.

Proposed Wording:

Recognizing Safety Related Conditions

During the annual Hazwoper/emergency response training sessions, Compliance will instruct Operations personnel, local and regional management and control center personnel in how to recognize what constitutes a safety related condition per 3.1.5; Reporting Criteria, page 35. In addition, Compliance will outline who personnel need to contact for any interpretations. Compliance will take the lead in completing the required paperwork per the Compliance Manual. To verify personnel have a thorough knowledge of safety related conditions or where to find the information, questions will be included on the Hazwoper/emergency response exam which requires a passing grade of 70%. The same rules apply where they will be required to repeat the group training or online course.

Reason for Change: Compliance requirement

195.402 (f) Safety-Related condition reports. The Manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of 195.55.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM C

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: January 26, 2006

O&MP Revision Request Form

Submitter: Terri Picton		**Date:** October 15, 2007
Select Book:	☒ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Book 1, Tab 5	**Subject Title:** Supervisor Knowledge of Emergency Response Procedures	
Subject Revision Date (printed on bottom of page): Whenever the revision pack goes out		

Existing Wording:

There is no existing wording that states that Supervisors are required to complete the training.

Proposed Wording:

To verify and ensure that personnel and supervisors learn and maintain a thorough knowledge of Hazwoper and emergency response procedures, an annual exam will be given to which employees must attain a score of 70% or greater to pass. Employees who do not receive a passing grade will be required to repeat the training or complete an online version until they are successful. Any employee who has not received a passing grade is limited to work activities where this training is not required. Copies of the exam and scores are available from the Safety Department.

Reason for Change:
Compliance Requirement;
§195.403(c). Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are responsible to ensure compliance.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM D PART 1

Jim D Stephenson/CNPL/Enbridge @IPL

05/31/2006 08:23 AM

To Mike D Goman/LPL@LPL

cc

bcc

Subject Fw: Revised Verbal Communication Procedure

----- Forwarded by Jim D Stephenson/CNPL/Enbridge on 05/31/2006 07:22 AM -----

ENBRIDGE

Next >> Prev << Tof C Backtrack Quit

a) Call Out / Verbal Communications - Equipment Problems/AOC's

In the event of equipment problems or Abnormal Operating Conditions after hours, contact:

- residence
- pager
- cellular
- 24-hour manned location (in the specific area)
- regional/district management

In the event of equipment problems or Abnormal Operating Conditions during normal working hours, contact:

- station or location (with man on-site)
- radio/call unit in truck
- pager
- cellular
- other maintenance personnel in the area (to attempt to make contact)
- 24-hour manned location (in the specific area)
- regional/district management

Note: If the equipment problem or Abnormal Operating Condition is of a nature that will require ongoing non-routine communications between the field and the control centre (e.g. mainline leak), develop a site specific communications plan with on-call or emergency response personnel to ensure that two-way voice communications are available, as required, between the control centre and the location(s) of the AOC. These communication methods could include cellular phones, pagers, company radio towers, satellite telephones, or other technology. This communication plan should be maintained for the duration of the AOC and changed when site conditions change (e.g. command post established, shift change, etc.).

Pipeline Control System

Operators rely on a computer-based pipeline control system (PCS) for safe and efficient control of flow and pressure. This supervisory control and data acquisition (SCADA) system includes subsystems to ensure pipelines do not exceed the maximum operating pressure (MOP) limits required by Code of Federal Regulations (CFR) Title 49, Part 195.406 Maximum Operating Pressure (USA) and the National Energy Board – Onshore Pipeline Regulations (CAN).

NOTE: Design and pressure testing records that justify MOP are permanently maintained as identified in Tab 04, Recordkeeping.

The line pressure monitor, a main subsystem, protects the pipeline from overpressure in the event of a communications failure. The line pressure monitor uses pressure limits calculated by the operating pressure limits program. This program calculates the allowable pressure limits for individual segments of each pipeline using MOP data and taking into account operational factors such as liquid density and viscosity. As well, each pump station on the pipeline is equipped with double-redundant high-pressure shutdown devices that ensure pressure does not exceed MOP limits.

The PCS continually archives operating data, messages, and alarms, which can be also exported to an external database called the pipeline information (PI) system. The PI system assists technical and operations employees in identifying and analyzing abnormal or unusual operating conditions.

Operators use the PCS and SCADA systems to operate the mainline pump units, station control valves, and sectionalizing valves on the mainline. Operators regulate pressure and flow rate in the pipeline, while tank farm operators handle injections and breakout volumes at field locations where receipts come in from the shippers. Deliveries are also handled locally by employees from a variety of job classifications.

Like the pipeline operators, field workers also rely on computer-based systems to complete tank swings, start and stop deliveries and/or injections, prove meters, and generate tickets. Area Operations staff are responsible for these tasks and other related tasks. Pipeline Maintenance (PLM) crews are responsible for tasks related to pipe modifications or repair and right-of-way maintenance. Area Operations groups and PLM crews are based at strategic locations in each region.

Communications

Operating the equipment and coordinating the efforts of employees dispersed over hundreds of miles requires sophisticated and reliable communications facilities to ensure safe, efficient, system operation.

The PCS depends on telecommunications technology to link control center computers to remote terminal units (RTUs) located at pump stations. The data circuits are primarily leased telephone lines, which are a combination of copper wire, fiber optic cable, and microwave systems.

The leased lines are asynchronous, full-duplex dedicated lines. This means that any number of data characters can be transmitted simultaneously in both directions, over lines reserved for data transmission (i.e., no voice communications).

Voice communication in each region relies on a general mobile radio system, consisting of mobile radio/telephone units, hand-held units, base stations, and repeater towers. Each vehicle is equipped with a mobile radio/telephone. Key personnel are assigned a cellular telephone or a pager.

Voice communication between the control center and tank farm operators relies on the traditional long distance telephone system. To provide a record and to prevent misunderstandings, electronic mail and fax machines supply printed operating instructions and confirmation of actions taken.

Each mode of communication has a backup system. For the PCS data circuits, this is the standard dial-in telephone voice line. Since the PCS relies on these circuits to protect the pipeline from high pressure, the system includes a provision for communications failure called COMM-OUT discharge protection. This software program automatically applies a set point that prevents discharge pressure from exceeding static maximum pressure values, and activates an appropriately calibrated pressure switch. Like other discharge pressure safeguards, this includes separate redundant hardware.

ITEM E

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: January 26, 2006

O&MP Revision Request Form

Submitter: Terri Picton		**Date:** October 15, 2007
Select Book:	☐ Book 1: General Reference ☐ Book 2: Safety ☒ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: 03-02-02	**Subject Title:** Right-of-Way Signs and Markers	
Subject Revision Date (printed on bottom of page): Whenever the revision pack goes out		

Existing Wording:
There is no existing wording in the Main Line O&MP Series that describes the procedures of placing sufficient number of line markers along the right of way. The procedure below comes from the Enbridge Gathering Systems O&MP Manual and has been approved by Region Management.

Proposed Wording:
Add the following as a bullet point to the Requirements for Warning Signs.

In general, pipeline markers should be visible at any point you are standing.

Reason for Change:
Compliance Requirement
§195.410. Line Markers. (a) (1) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:
(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately know.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM F PART 1

Job Plan:	MP2022R
Description:	Relief Valves, Full Flow - PMREG MP2022R replaces: MP00001746 as of AUG/17/2006
Lead Craft:	
WO Priority:	1
Downtime:	N
Interruptible:	N
Duration:	1.5

OP	Description	Hours
5	Prior to Inspection Contact Region Engineering to Ensure Pressure Relief Valve is Properly Sized This will be based on Potential Changing Operation Parameters, it is required to contact regional engineering to ensure that it is adequate from the stand point of capacity and reliability of operation for the service in which it is employed.	0
10	Inspect and test as per CSA Z662 - to ensure it is in good operating condition.	0
20	Check that PSV is adequate from the standpoint of capacity and reliability for its service.	0
30	Set to function at the correct pressure.	0
40	Check that PSV is properly installed and protected from dirt and other conditions that might prevent its operation.	0
50	Test via the in-place pop test or remove and have bench tested.	0
60	Time to complete Job Plan: 1.5 hours	1.5

ITEM F PART 2

Job Plan: MP2003QR

Description: Pressure Relief Valve - DOT

MP2003QR replaces:

MP255

as of AUG/17/2006

Lead Craft:

WO Priority: 1

Downtime: N

Interruptible: N

Duration: 1

OP	Description	Hours
5	Prior to Inspection Contact Region Engineering to Ensure Pressure Relief Valve is Properly Sized This will be based on Potential Changing Operation Parameters, it is required to contact regional engineering to ensure that it is adequate from the stand point of capacity and reliability of operation for the service in which it is employed.	0
10	Isolate thermal relief valve by closing inlet valve	0
20	Connect testing pump or supply bottle and check relief valve set point.	0
30	Adjust if valve relieves out of tolerance. See long description for tolerance standards. The pop pressure from the set pressure should not exceed + 0/- 2 psi. for pressure settings less than or equal to 70 psi, or + 0/- 3 percent for set pressures greater than 70 psi. In other words, relief valves with a specified setting of 70 psi or less are within tolerance and do not have to be adjusted (leave as found) if they relief under a test pressure of plus 0 psi or minus 2 psi of the specified setting. Example - a relief valve with a 60 psi specified setting is within tolerance if found to relief under a test pressure of 58 to 60 psi. If 62 psi is the relief pressure then re-adjustment the relief valve to relief at the specified setting of 60 psi. For relief valves with specified settings of over 70 psi, the valve is	0

ITEM G PART 1

Manual Title: Book 3. Pipeline Facilities	Operations Manual REVISION REQUEST

Name: Mike D Goman

Subject Title: Tank Repair and Alteration

Subject No.: 09 - 03 - 07 (e.g. 02-01-03)

Subject Date: April 1, 2006 (printed at bottom of the page)

Aug 3, 2006

Existing wording: None

Approved wording: Overfill Protection
If an aboveground tank over 600 gallons in capacity is significantly altered, an overfill protection system must be installed in accordance with API RP 2350, Overfill Protection for Storage Tanks in Petroleum Facilities.

Subject Title: Overview of Tank Maintenance

Subject No.: 09 - 01 - 01 (e.g. 02-01-03)

Subject Date: April 1, 2006 (printed at bottom of the page)

Existing wording: None

Approved wording: Related Standards, Industry
American Petrolum Institute (API):

- Std 2510, Design and Construction of LPG Installations

Reason for Change: To ensure compliance with 49CFR 195.428(c).

Protocol Question:

.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				

ITEM G PART 2

Manual Title: Book 3. Pipeline Facilities	Operations Manual REVISION REQUEST

Name: Mike D Goman
Subject Title: Tank Repair and Alteration
Subject No.: 09 - 03 - 07 (e.g. 02-01-03)
Subject Date: April 1, 2006 (printed at bottom of the page)

Aug 3, 2006

Existing wording: None

Proposed wording: Add Definition: Significant Alteration - An alteration to an aboveground storage tank or pressure vessel that requires subsequent hydrostatic testing of the tank to comply with regulatory requirements and/or to verify the integrity of the tank or vessel after the alteration has been made.

Add verbiage:
(US Flag) If an aboveground storage tank over 600 gallons in capacity is significantly altered, an overfill protection system must be installed (if not already installed prior to the alteration) in accordance with API RP 2350. For tanks constructed to API Standard 2510, overfill protection systems must be installed in accordance with Section 5.1.2 of API Standard 2510.

Reason for Change: This will be a Notice of Amendment (NOA) stemming from the recent Team O&MP audit by the Office of Pipeline Safety. We have been requested to add this verbiage to ensure compliance with §195.428(c).

Protocol Question:

.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				

From the O&MP Exit Notes:

1. 195.428(c) – There should be procedures in the O&M manual about installing overfill protection per API RP 2350 on breakout tanks (API 2510, API 650, etc) when the tanks are significantly altered.

ITEM H

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Revision Request Form

Submitter: Jay A Johnson		**Date: 10/30/07**
Select Book:	☒ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: 03-02-01		**Subject Title: Maintain current list of Excavators/Contractors/Farmers**
Subject Revision Date (printed on bottom of page): During next revision package		

Existing Wording:

The existing wording does not cover how we maintain a current list of excavators.

Proposed Wording:

In accordance with regulatory requirements, each region will maintain a list of persons who normally engage in excavation activities in the areas in which the pipeline is located. This list may be generated by using any of the following resources:

- information gathered from invitation lists of existing damage prevention meetings
- contractor /excavators known by company personnel to operate within their region
- lists generated by state one call / damage prevention agencies based on one call requests
- contractors identified in the field via "Documentation of ONE CALL Violations" forms

In areas where logging activities may impact our ROW or is identified as an issue, the region shall make every effort to educate the loggers of the following:

- basic pipeline safety information
- location of pipelines
- Enbridge crossing policies
- how logging equipment may pose a threat to the pipeline and the safety of the logging operation.

Records of this communication/education must be maintained in the Region Office.

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Reason for Change:

Compliance requirement;

195.442 Damage Prevention Program. (C) The damage prevention program required by paragraph (a) of this section must, at a minimum: (1) Include the identity, on a current basis of persons who normally engage in excavation activities in the area in which the pipeline is located.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM I

ENBRIDGE

Manual Title: Book 3. Pipeline Facilities	Operations Manual
	Revision Request

Name: US Compliance

Date: 06/02/2006

Subject Title: Damage Prevention

Subject No.: 04 - 02 - 02

Subject Date: 04/01/2006

Existing wording none

Proposed wording: One-Call System

Notify the One-Call Center at least 2 to 3 working days before beginning any below grade activity

NOTE: The One-Call Center will ~~advise~~ notify facility owners and request that all buried facilities in the area of the proposed activity are located and staked.

NOTE: In the USA, the Information Retrieval Ticket Handling (IRTH) system receives notification from the One-Call Center and assigns One-Call tickets to the appropriate service area. In the USA, for emergency work during normal working hours and as backup to the IRTH system, the One-Call Center or the region (depending on the service area) will notify the locator directly. For emergency work after hours, the Edmonton Control Center (ECC) or the region (depending on the service area) will notify the locator directly.

Reason for Change: to ensure compliance with CFR 49, 195.442 (c) (3)

ITEM J

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Revision Request Form

Submitter: Jay A. Johnosn		**Date: 10/30/07**
Select Book:	☐ **Book 1: General Reference** ☐ **Book 2: Safety** ☐ **Book 3: Pipeline Facilities**	☐ **Book 4: Welding** ☐ **Book 5: Petroleum Quality & Measurement** ☐ **Book 7: Emergency Response**
Subject Number: Corrosion Control Guidelines	**Subject Title: Ensuring Supervisor Knowledge**	
Subject Revision Date (printed on bottom of page): Whenever the next revision goes out.		

Existing Wording:

We did not have existing wording to cover this however all Enbridge Corrosion Technicians are required to get a NACE CP Level 1 certification within one year of employment or transferring to the position.

Proposed Wording:

To ensure supervisors have knowledge of what tasks their personnel complete, they are responsible to either OQ qualify or witness the cathodic protection related qualifications. In addition, the Senior Corrosion Technician will maintain a list of what CP specific tasks each non-cathodic supervisor is responsible for to maintain compliance with DOT Part 195 and the Enbridge Corrosion Control Guidelines. The Senior Corrosion Technician will review these tasks with the Area Supervisors at least once per calendar year.

Reason for Change:

Compliance Requirement;

195.555 What are the qualifications for Supervisors? You must require and verify that supervisors maintain a through knowledge of that portion of the corrosion control procedures established under 195.402 (C) (3) for which they are responsible for insuring compliance.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM K

(d) Breakout tanks. You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

(e) Corrective action. You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

13.3.2 - Federal Regulations for Test Stations

§192.469 - External Corrosion Control: Test stations.

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

§195.567 - Which pipelines must have test leads and what must I do to install and maintain the leads?

(a) General. Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.

(b) Installation. You must install test leads as follows:

(1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

(2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.

(3) Prevent lead attachments from causing stress concentrations on pipe.

(4) For leads installed in conduits, suitably insulate the lead from the conduit.

(5) At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(c) Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §195.571.

Once the equipment is verified to be in working order, the FDC operator attaches the spool of wire on the backpack. One end of the wire is attached to a pipeline test lead, and the other to the negative terminal of the FDC. The half-cell walking poles are then connected in parallel to the positive terminal. At this point, once the FDC is turned on and loaded with the proper program, the surveying begins. The pipeline is flagged, usually at 100 feet intervals, either beforehand or while the survey is occurring. The FDC operator then walks at a standard pace (typically 2-½ feet) while the FDC automatically collects data. When a flag is passed or if a portable counter is used and it hits 100 feet, the operator enters this into the FDC and the computer adds 100 feet to the survey distance. This is how distance is accounted for.

12.5.3 - Typical Crew Organization for Close-Interval Survey

A close-interval survey can be performed with three people: a lead person, an FDC operator, and a trail person.

This crew option has the lead person flagging (locating) the line immediately ahead of the FDC operator with a 100-foot long rope attached.

When the end of the rope passes the previously laid flag, another flag is placed It is the FDC operator's responsibility to notify the lead person when another flag should be placed.

The trail person's responsibilities are to help maneuver the automobiles and pick up the wire. It is most important that all wire be picked up after the survey is complete, as it can cause problems for farmers, etc.

Another option is to flag the line ahead of time. This consumes more total personnel hours than the first option, but the footage accuracy is improved because less flagging errors will be made. This can become very important when trying to relocate indicated trouble spots.

12.5.4 - Correcting for IR Drop in Close-Interval Surveys

49 CFR Part 192, Appendix D, II states that "Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement..." Additional information can be found in the "A. W. Peabody Book."

The "other" IR drops mentioned above are soil and metal IR drops. Soil IR drop is caused by cathodic protection current flowing in the soil. Metal IR drop is caused by cathodic protection current flowing in the pipe.

The interpretation of the voltage measurement which requires the consideration of soil and pipe IR drops is that a correction for this voltage drop is not required at any test point and does not require any changes with the survey data, which was taken with the current applied in the system. The term "considered" as set forth in the law means that there may be instances where large amounts of currents are flowing in the soil and carrier pipe and may cause the observed reading to be higher. This IR drop is maximum at the rectifier groundbed locations and decreases with remoteness to the groundbed and perhaps decreases to zero at the midpoint between two current sources.

The interpretation of the current law is that readings for annual test point surveys are to be taken with the protective current applied and the IR drops considered, but not necessarily subtracted. It is desirable to aim for potentials near -1.0 Volt, rather than -0.850 Volt. This allows a "cushion" of 150 mV for IR drop. Other methods of consideration rely on experience and line history. If either the current to the line (I) or the soil resistivity (R) is low, the IR drop is also expected to be low. If the inspection of the lines documentation shows that corrosion is not occurring and the potentials are at least -0.850 Volts, then it can be assumed that the IR drop is not significant enough to cause a problem. The occurrence of significant corrosion, high currents, high soil resistivity, large changes in pipe depth, or other conditions may warrant the actual determination of the IR drop.

Soil IR drop should be considered at many road crossing, where the pipe may be twice as deep as the normal depth away from roads, gullies and rivers, which multiplies the IR drop proportionally to the depth of the pipe.

There are three common methods of ascertaining the amount and the effect of IR drop on pipe to soil readings, which are current interruption, location of the reference cell at the pipe/soil interface, and the remote step-wise reading with calculations. None of these three methods are perfect in predicting the amount of IR drop present, and each is described in the next three following paragraphs.

Current interruption comes closest to removing the IR drop in both the soil and pipe if done properly. This method requires all current sources to be interrupted simultaneously and synchronization of all influencing rectifiers, bonds and galvanic anodes, and must be timed to have identical "on-off" cycles for the best and most accurate results. Remotely located galvanic anodes to the testing area probably have little or no effect on this method due to the low current output, low driving voltage and distant location. This method is usually chosen when making a close-interval survey and is the best method to employ when attempting to satisfy the 100 millivolt polarization shift criterion with no current there is no "IR drop." It should be realized that in most cases it is impossible to stop all current flow and some error will always be present when using this method. Lateral or branch lines which have no current sources other than through the bond to the mainline or other lateral or branch lines probably come closest to measuring true IR drop when the current supplying bond is opened and closed with an interrupter with a very short off-cycle.

ITEM M

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Revision Request Form

Submitter: Jay A Johnson		Date: 10/30/07
Select Book:	☐ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Cathodic Protection Guidelines 12.5	Subject Title: Close Interval Surveys	
Subject Revision Date (printed on bottom of page): During the next revision cycle		

Existing Wording:

The existing wording describes the process to complete a Close Interval Survey but not the criteria for completing one.

Proposed Wording:

Alternative Survey Methodology
In areas where the Annual Survey identifies sub-standard potentials, a close interval survey or other survey capable of detecting specific anomalies should be considered. In USA, additional survey measures may be required to accomplish the objectives of NACE RP0169, section 10.1.1.3. Such measures may identify locations where:

- Additional protective current is required through expansion of or addition to the existing CP system,
- An unknown interference issue inhibits the performance of the existing CP system,
- Repair of coating damage may improve performance of the existing CP system, or
- Additional assessment methods should be considered.

Results of these additional measures will be analyzed and compared with the In-Line Inspection Tool Runs, by the lead Corrosion Control Coordinator, regional CP Specialist and Pipeline Integrity

Reason for Change:

Compliance Requirement;

195.573 **What must I do to monitor external corrosion control? (a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571;**

(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable

technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE standard RPO0169-96 (incorporated by reference, see Sec. 195.3).

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM N

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	**Effective Date: August 01, 2006**

Revision Request Form

Submitter: Jay A Johnson		**Date: 10/30/07**
Select Book:	☐ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Cathodic Protections Guidelines 11.3.2		**Subject Title: CP Design for Above Ground Storage Tanks**
Subject Revision Date (printed on bottom of page): When the next revision package goes out		

Existing Wording:

The existing verbiage references NEC and NACE but not API

Proposed Wording:

All regulated buried or submerged pipeline and breakout tanks must be protected by a cathodic protection system no later than 1 year after the pipeline is constructed, relocated, replaced or otherwise changed.

The cathodic protection system shall be operated and maintained in accordance with API Recommended Practice 651 for the useful life of the breakout tank. In addition, the cathodic protection system (on the pipeline) shall be maintained for the useful life of the pipeline.

NOTE: In the USA, tanks moved or constructed on a new location after October 2, 2000 shall have a cathodic protection system installed in accordance with API Recommended Practice 651.

Reason for Change:

Compliance Requirement;

195.573 What must I do to monitor external corrosion control? (d) Breakout tanks. You must inspect each cathodic protection system used to control corrosion on the bottom of an above ground storage tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under Sec. 195.402(c) (3) why compliance with all or certain operation and maintenance provisions of API recommended Practice 651 is not necessary for the safety of the tank.

O&MP Quality Management System (QMS)	**ENBRIDGE**
Revision Request	**Effective Date: August 01, 2006**

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM 0

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: August 01, 2006

Revision Request Form

Submitter: Jay A Johnson		Date: 10/30/07
Select Book:	☐ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Corrosion Control Guidelines	Subject Title: Repair Timing	
Subject Revision Date (printed on bottom of page): Whenever the next revision goes out		

Existing Wording:

We currently don't have wording that addresses this.

Proposed Wording:

Any corrosion or cathodic protection related deficiencies that could adversely affect the safe operation of the pipeline shall be reviewed and prioritized by the appropriate supervisor.

In general, repairs will be made as soon as practicable before the next annual survey or, if required, during the next budget cycle. However, if any deficiencies, such as but not limited to:

- critical bond connection problems,
- rectifier component failure which may pose an electrical hazard,
- broken bond cables which may result in significant interference across an isolation device,
- discovery of a new sever interference problem causing detrimental damage to EPL,
- broken DC cables which may pose a spark hazard in a hazardous area,

that present a hazard to persons or property, the repair will be made immediately or the affected part of the system shall not be operated until the deficiency has been corrected and/or temporary restrictions have been put in to place.

Reason for Change:

Compliance requirement;

195.573 What must I do to monitor external corrosion control/ (e) Corrective Action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401 (b)

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

ITEM P

O&MP Quality Management System (QMS)	ENBRIDGE
Revision Request	Effective Date: January 26, 2006

O&MP Revision Request Form

Submitter: Jay A Johnson		**Date:** 10//30/07
Select Book:	☐ Book 1: General Reference ☐ Book 2: Safety ☐ Book 3: Pipeline Facilities	☐ Book 4: Welding ☐ Book 5: Petroleum Quality & Measurement ☐ Book 7: Emergency Response
Subject Number: Corrosion Control Guidelines	**Subject Title:** Electrical Isolation	
Subject Revision Date (printed on bottom of page): Whenever next version is released		

Existing Wording:

No existing wording clearly covered this.

Proposed Wording:

Electrical isolation must be achieved and maintained in accordance with NACE SPO286, Electrical Isolation of Cathodically Protected Pipelines. Electrical isolation must be checked annually, not exceeding 15 months. Methods for checking may include;

- Interrupted pipe-to-soil readings measured on both sides of isolation kits.
    - A shift in the potential of a foreign facility that is greater than 10mV and due to the interruption of Company rectifiers may indicate a shorted isolation device. Further investigation of an expected short may include:
        - Checking the device with an electronic insulation checker to identify the shorted component(s), or
        - Separating the insulating device to inspect the insulating surfaces for damage and recording additional pipe-to-soil readings on both sides of the device while it is separated. No change from the previously recorded readings would indicate a stray current interference problem rather than a short and additional investigation would be required to correct the problem.

        CAUTION: Piping must be bonded while separating a pipeline to prevent unintentional static discharge.

- Where bonds are installed across Company facilities for continuity purposes, bond integrity will be confirmed by:
    - Measuring similar pipe-to-soil potentials on both sides of the bond.
    - Measuring current magnitude and direction through the bond, and
    - Observing a change in potential when the bond connection is opened.

NOTE: High resistant bonds between Company facilities shall be repaired or replaced as outlined in repair timing section

- Where resistance bonds are required between Company and foreign facilities to control stray current interference, bond integrity will be confirmed by:
  - Measuring a foreign pipe to soil potential equal to or more negative than the potential of the foreign facility with no depressing effects due to interference,

NOTE: Foreign facilities that are independently cathodically protected should be maintained at a protected level of at least negative 0.85 volts with respect to a saturated copper/copper sulfate half-cell. This minimum protection level is not required when the foreign facility is not independently cathodically protected.

  - Measuring current magnitude and direction through the bond, and
  - Observing a change in potential when the bond connection is opened.

Reason for Change:

Compliance Requirement;

195.575 Which facilities must I electrically isolate and what inspections, tests, safe guards and when they are required.

Please submit this form to Canadian Compliance by:
Mail/Interoffice: 10201 Jasper Avenue, Edmonton AB T5J 3N7
Fax: (780) 420-8801
Email: janet.huggett@enbridge.com or tamara.leshchyshyn@enbridge.com

13.3.3 - Federal Regulations for Corrosion Control Records

§192.491 - Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

§195.589 - What corrosion control information do I have to maintain?

(a) You must maintain current records or maps to show the location of --

  (1) Cathodically protected pipelines;

  (2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and

  (3) Neighboring structures bonded to cathodic protection systems.

(b) 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.

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §§195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

13.4 - Test Points

In order to help inspect and maintain the integrity of the pipeline, test points have been installed at approximately one-mile intervals. Keep in mind, that in some instances it may be impractical to install test stations at a one-mile interval. Therefore, it is possible to find them spaced further apart. In addition to the standard test stations, foreign line test stations, isolation flange test stations, casing test stations; block valves, permanent reference cells, transitions and aboveground storage tank perimeters are also used as test points. Although Enbridge's standard test station is the Cott "Big Fink" or "Little Fink", we will discuss other brands of test stations. Basically, they all serve the same purpose of providing a means to monitor the cathodic protection system.

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 8, 2007

Mr. Dan Tutcher, President
Enbridge Energy, Limited Partnership
1100 Louisiana, Suite 3300
Houston, TX 77002-7002

CPF No. 4-2007-5006M

Dear Mr. Tutcher

On May 8-12, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), NY PSC, and MNOPS, pursuant to Chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of Enbridge Energy's procedures in Superior, WI. As a result of the inspection Enbridge Energy was issued a Notice of Amendment on March 1, 2007. This Notice proposed amendment of your procedures to assure safe operation of your pipeline facility.

Enbridge Energy submitted its amended procedures on October 31, 2007. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you that no further action is necessary and this case is closed. Thank you for your cooperation.

Sincerely,

Warren Miller
for
R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 1, 2007

Mr. Dan Tutcher, President
Enbridge Energy, Limited Partnership
1100 Louisiana, Suite 3300
Houston, TX 77002-7002

CPF 4-2007-5006M

Dear Mr. Tutcher:

On May 8-12, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), NY PSC, and MNOPS pursuant to Chapter 601 of 49 United States Code inspected Enbridge Energy, Limited Partnership (Enbridge) procedures for operations and maintenance in Superior, WI.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Enbridge's plan or procedure and are described below:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies**

   (a)General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

A. §195.402 (C)(13). Periodically reviewing the work done by operator to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

Enbridge Energy procedures did not contain a formal procedure to periodically review the work of personnel to determine the effectiveness of the O&M procedures relating to the pipeline safety regulations. Enbridge needs to amend their procedures to include reviewing the work of personnel to determine the effectiveness of the O&M procedures relating to the pipeline safety regulations.

B. §195.402(f) Safety related condition reports.

Enbridge Energy procedures did not clearly state that employees are trained on an ongoing basis to recognize safety related conditions. Enbridge needs to amend their procedures to state that employees are trained on an ongoing basis to recognize safety related conditions.

C. §195. 403 Emergency Response Training. (c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are responsible to ensure compliance.

Enbridge Energy procedures did not clearly state that supervisors are included in the annual training. Enbridge needs to amend their procedures to state that supervisors are included in annual training.

D. §195. 408 Communications. (b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:
3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and,

Enbridge Energy procedures did not fully describe the actual description of two-way communication methods and procedures (e.g. cell phones, landline to radio towers, etc) between the Edmonton Control Center and the scene of abnormal operations or emergencies. Enbridge needs to amend their procedures to describe the actual description of two-way communication methods between the Edmonton Control Center and the scene of abnormal operations or emergencies.

E. §195. 410 Line Markers. (a)(1) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

Enbridge Energy procedures did not fully describe the practice of placing a sufficient number of line markers along the right-of-way. Enbridge needs to amend their procedures to describe the practice of placing a sufficient number of line markers along the right-of-way.

F. §195.428 Overpressure safety devices and overfill protection systems. (a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

Enbridge Energy procedures did not address how the capacity of the relief valve is determined to be adequate. Flow capacity needs to be verified in light of changing operational parameters since the relief valves were originally installed. Enbridge needs to amend their procedures to describe how the capacity of the relief valve is determined to be adequate. Enbridge procedures need to take into account changing operational parameters for relief valves since they were originally installed.

G. §195.428 Overpressure safety devices and overfill protection systems. (c) Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API Recommended Practice 2350. However, operators need not comply with any part of API Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by §195.402 why compliance with that part is not necessary for safety of the tank.

Enbridge Energy procedures did not fully describe the installation of overfill protection per API RP 2350 on breakout tanks that are significantly altered. Enbridge needs to amend their procedures to describe the installation of overfill protection per API RP 2350 on breakout tanks that are significantly altered.

H. §195.442 Damage prevention program. (c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
(1) Include the identity, on a current basis of persons who normally engage in excavation activities in the area in which the pipeline is located.

Enbridge Energy procedures did not describe how the list of excavators is kept current.

I. §195.442 Damage prevention program. c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
(3) Provide a means of receiving and recording notification of planned excavation activities.

Enbridge Energy procedures do not describe how one-call notifications are handled once notifications are received. Enbridge needs to amend their procedures to describe how one-call notifications are handled once notifications are received.

J. §195.555 What are the qualifications for supervisors?

Enbridge Energy procedures were not clear on the requirement for supervisors to maintain a thorough knowledge of corrosion control procedures, nor did the procedures state how supervisor knowledge of corrosion control was to be verified. Enbridge needs to amend their procedures need be clearly state the requirement for supervisors to maintain a thorough knowledge of corrosion control procedures and these procedures need to state how supervisor knowledge of corrosion control is verified.

K. §195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?

Enbridge Energy procedures were not clear on how test leads are maintained. Enbridge needs to amend their procedures to state how test leads are maintained.

L. §195.571 What criteria must I use to determine the adequacy of cathodic protection?

Enbridge Energy procedures did not address IR drop considerations for the (–850 mV) on-criteria. Enbridge needs to amend their procedures to address IR drop considerations.

M. §195.573 What must I do to monitor external corrosion control? (a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

Enbridge Energy procedures did not describe in what circumstances close interval surveys are completed. Enbridge needs to amend their procedures to describe in what circumstances close interval surveys are completed

N. §195.573 What must I do to monitor external corrosion control? (d) Breakout tanks. You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note

in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

Enbridge Energy procedures need to ensure that cathodic protection system maintenance and testing of breakout tanks is in conformance with API 651. Enbridge needs to amend their procedures to ensure that cathodic protection system maintenance and testing of breakout tanks is in conformance with API 651.

O. §195.573 What must I do to monitor external corrosion control? (e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

Enbridge Energy procedures did not describe the timing for correction of deficiencies found. Enbridge needs to amend their procedures to describe the timing for correction of deficiencies found.

P. §195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

Enbridge Energy procedures need detailed descriptions of electrical isolation installations, inspections, tests, safeguards and when they are required. Enbridge needs to amend their procedures to provide detailed descriptions of electrical isolation installations, inspections, tests, safe guards and when they are required.

O. §195.589 What corrosion control information do I have to maintain?

Enbridge Energy procedures do not specify the retention time for atmospheric corrosion inspections. Enbridge needs to amend their procedures need to specify the retention time for atmospheric corrosion inspections.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2007-5006M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

LETTER OF CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 23, 2007

Mr. Terry L. McGill
President
Enbridge Energy Partners, LP
1100 Louisiana, Suite 3300
Houston, TX 77002

CPF 3-2007-1004C

Dear Mr. McGill:

On October 17-20, 2005 and November 20-21, 2005, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your records and facilities for Enbridge Energy's Vector Pipeline in Illinois and Indiana.

As a result of the inspection, the following items were identified as a concern:

a) During the inspection, it was noted that several test leads which were broken during construction and never repaired appear on the annual survey year after year. A close interval survey following construction indicated there are adequate test stations to demonstrate protection, and in addition, a number of the broken test leads are being repaired. It was discussed with your representatives that broken test leads should be taken off the annual survey until they are repaired.
b) During the field inspection, low potentials were observed at the Crete Meter Station in Illinois on October 20, 2005. Your representatives indicated a remediation program is

underway to correct these deficiencies. A new ground bed and rectifier installed in July 2006 has brought the potentials up to satisfactory levels.

We hope you will consider these areas of concern as an opportunity to improve your existing pipeline safety program. If we can answer any questions or be of any help, please call us at 816-329-3800.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 3-2007-1004C.**

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Vector Pipeline™

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

RECEIVED MAR 2 0 2007

March 19, 2007

MAR 2 3 2007

Ivan A Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Room 462E
Kansas City MO 64106

Re: CPF 3-2007-1004C
2005 Vector Records and Field Audit

Dear Mr. Huntoon:

Based on PHMSA's Field and Records inspection in October and November of 2005 of the Illinois and Indiana portion of Vector Pipeline, the following items were noted as requiring our attention.

In reference to item (a) in CPF 3-2007-1004C Enbridge completed a close interval survey after construction to verify that the number of test leads was adequate to demonstrate sufficient Cathodic Protection. However, Enbridge still had a program in 2005 and 2006 to repair/replace 24 of the broken test leads. This work has been completed and any leads determined unnecessary will be removed for clarity.

In reference to item (b) in CPF 3-2007-1004C Enbridge had taken budgetary measures to address the low potentials prior to the 2005 field inspection. However, the actual work was not completed until the 2006 work season. As mentioned in your letter the addition of the new ground bed and rectifier has brought the Cathodic Protection potentials up to satisfactory levels at the Crete Meter Station.

We trust these items have been addressed to your satisfaction. However, if you have any additional questions, please let me know. We appreciate the opportunity to work with PHMSA to correct any perceived deficiencies to ensure overall pipeline safety.

Sincerely,

Mark Willoughby

cc: Steve Irving
Craig Fishbeck
Tom Fridel
Terrance McGill
Leon Zupan

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 23, 2007

Mr. Terry L. McGill
President
Enbridge Energy Partners, LP
1100 Louisiana, Suite 3300
Houston, TX 77002

CPF 3-2007-1003W

Dear Mr. McGill:

On October 17-20, 2005 and November 20-21, 2005, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your records and facilities for Enbridge Energy's Vector Pipeline in Illinois and Indiana.

As a result of the inspection, it appears that you have committed a probable violation of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The item inspected and the probable violation is:

1. **§192.475 Internal corrosion control: General**
   (b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found-
   (1) The adjacent pipe must be investigated to determine the extent of internal corrosion:

Internal inspection was performed, but not documented on the Crete Meter Station hot tap performed on 3/18/2002.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Be advised that failure to do so will result in Enbridge Energy being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 3-2007-1003W.**

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Vector Pipeline™

Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Mark J. Willoughby, Manager
Compliance
Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

MAR 23 2007

RECEIVED MAR 2 0 2007

March 19, 2007

Ivan A Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Room 462E
Kansas City MO 64106

Re: CPF 3-2007-1003W
2005 Vector Records and Field Audit

Dear Mr. Huntoon:

Based on PHMSA's Field and Records inspection in October and November of 2005 of the Illinois and Indiana portion of Vector Pipeline, the following items were noted as requiring our attention.

In reference to Item (1) in CPF 3-2007-1003W Enbridge removed a coupon during the hot tap at the Crete Meter Station and did not have a documented Internal Inspection performed. A discussion was held with the Pipeline Maintenance Supervisor who performed the inspection but stated they neglected to complete the paperwork. Since that time a change was made to Enbridge's PLM Reporting System (software used to track all changes made to the Main Line) which requires documenting the inspection on an internal corrosion inspection report anytime the inside of the pipe is exposed. The PLM Reporting System asks a series of questions which will ensure that this form is completed in all applicable situations.

We trust these items have been addressed to your satisfaction. However, if you have any additional questions, please let me know. We appreciate the opportunity to work with PHMSA to correct any perceived deficiencies to ensure overall pipeline safety.

Sincerely,

Mark J Willoughby

Mark Willoughby

cc: Steve Irving
Craig Fishbeck
Tom Fridel
Terrance McGill
Leon Zupan

Compl Reg Phil Steward

Enbridge Pipelines (Lakehead) L.L.C.
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Compliance
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Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

RECEIVED
03/07/05

March 4, 2005

NEXT DAY MAIL

Mr. Ivan Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF 3-2004-5009 Grand Rapids, MN 2/19/04 Incident

Dear Mr. Huntoon:

Further to our telephone discussions with you, Dave Barrett and Phil Archuletta, as well as Mike McGrath and Brian Pierzina of the Minnesota Office of Pipeline Safety on February 7, we have attached our comments addressing each of the following concerns:

1. Is this aquifer connected to a municipal water supply (i.e., Grand Rapids, MN)?

2. Provide the timelines on all drilling operations to delineate the oil plume including the results of each well.

3. Provide an estimate of how long the pipeline was leaking prior to discovery.

4. Provide a listing of historic Line 2, 26-inch leaks.

5. Further clarify the reasoning behind the selection of "natural forces - earth movement – subsidence" as the cause of the leak.

We trust that the attached information confirms what we discussed and further answers the questions raised during our discussion. Should you have any concerns or specific questions regarding this information, please contact me.

Sincerely,

Mark J. Willoughby

Mark J. Willoughby

Attachment
c: Steve Irving
Walter Kresic
Mike McGrath
Brian Pierzina
Mark Sitek

Attachment 1

Enbridge has been in contact with the Grand Rapids public utility staff, and we understand that the city has five water supply wells. The closest municipal well is approximately 3600 feet southeast of the leak site.

Based on what we know of the leak site, technical factors of petroleum impacted groundwater, and typical construction of municipal wells (normally screened deep), we do not feel the city supply is at risk. The area immediately south (down-gradient) from the leak site is remote. Further, petroleum impacts generally do not migrate far from the source (typically less than 500-1000 feet) and stay "high" (shallow) in the water table. Processes of natural degradation, dilution, and volatilization work to limit migration and expansion of a plume.

Attachment 2

Grand Rapids, MN – 02/19/04
Site Investigation Chronology

Following is a brief chronology of the site investigation that proceeded for the February, 2004 release near Grand Rapids, Minnesota:

2/19 and 2/20/04
A contract crew under Enbridge direction was performing a maintenance dig on Line 2 (26") at MP1007.33. The dig was being conducted in response to a dent with metal loss indication. Oil impacts were observed during the excavation at a depth of approximately four feet below grade, and the line was immediately shut down until the repairs were complete. Brian Pierzina, of the Minnesota Office of Pipeline Safety, arrived at the site that afternoon. The pipe was uncovered and cleaned and a rock was observed in contact with the pipe. Once the pipe was repaired, excavation attempting to remove all impacted soil began. Excavation occurred on the 19th and 20th until all accessible impacted soil was removed and landfilled. In summary, a total of approximately 395 cubic yards of impacted soil was removed from the site. All sidewalls of the excavation were sampled and determined to meet cleanup standards. The only remaining impacts were at the base of the excavation (approximately 16' deep). Deeper excavation was not completed since the reach of the excavator could not go any deeper and due to sloughing of soil, the 26" line and adjacent lines would also have needed to be supported.

The native soil at the site is a sand and gravel deposit with large boulders up to 4 feet in diameter. Groundwater was not encountered within the excavation and based on regional information was assumed to be about 40' deep.

During cleanup activities, the nearby landowners were notified of the leak by Enbridge. The right-of-way generally runs west to east. To the south is a heavily wooded area privately owned by the Buntrocks (later sold to the Stemwedels, the current owner), and south of that is undeveloped County land. To the north approximately 400 feet from the right-of-way are residential properties, the Stemwedels, and further northwest, the McDonalds. Area to the north is mostly wooded also. Topography slopes towards the south and was believed to be the direction of groundwater flow (away from the homes).

The attached topographic map illustrates the leak site area.

2/24/05
Enbridge submitted an e-mail update to MPCA, indicating that all impacted soil could not be removed via excavation, and that additional investigation would likely be necessary after receipt of soil samples and assessment of additional site characteristics.

2/25/04
Enbridge receives letter from nearby property owner (McDonald).

2/25/04
Enbridge responds to McDonald's inquiry

4/13/04
Dialogue with MPCA occurred following the completion of excavation activities, and Enbridge prepared and submitted on April 13, 2004 a report summarizing the release, remedial activities, soil sampling, groundwater receptors, and recommending additional site investigation due to remaining impacts in the base of the excavation. It is recommended that a boring be advanced at the release point until soil impacts are no longer identified or until groundwater is identified (in which case, groundwater will be sampled and additional wells installed). As well, adjacent landowner wells will be tested if landowners desire.

4/20/04
Buntrock's well was sampled, McDonalds decline. Results did not indicate any impacts. This information was forwarded to Buntrocks upon receipt and also forwarded to the MPCA.

4/21/04
Environment staff meets with MPCA to discuss a few open sites. Grand Rapids discussion firmed-up the approach for additional site investigation. Timeline was established with MPCA to begin investigation in mid-May once snow had melted and the area had dried out.

4/29/04
Buntrock's well sampling results are received. Results did not indicate any impacts. This information was forwarded to Buntrocks upon receipt and also forwarded to the MPCA.

5/24/04
MPCA notified via e-mail that drilling was beginning.

5/24 and 5/25/04
Drilling began, with a borehole as near to the leak/pipeline as possible. Air rotary drilling techniques were used and due to a significant amount of vibration from trying to core through boulders, a depth of only 20' was reached before drilling was stopped. At that point it was determined that a rotosonic drilling technique was better suited to the site conditions. Efforts to retain an appropriate drill rig ensued (but such rigs are limited and it was the heart of the busy season).

7/22 and 7/23/04
A small off-road rotosonic rig (to minimize site impact, clearing, etc.) was finally available and drilling commenced. Water was encountered at a depth of approximately 40 feet and a monitoring well was installed (MW-1). Oily soil was encountered throughout the drilling, but no free product in the initial bailing of the well. Approximately one week later the well was checked and about 1 foot of oil was observed. The MPCA was immediately informed and kept updated throughout the investigation process. (Note: wells must be allowed to stabilize before getting accurate monitoring results, typically days or weeks). These results indicated that much additional investigation would be necessary. The drill rig had prior contracts for other non-Enbridge work, thus Enbridge searched for and eventually found another company to complete the drilling. (Limited options were available with the necessary equipment (rotosonic), while also of the off-road variety in order to gain access.). Concurrent with this effort, Enbridge worked with the landowner regarding the additional access, and secured additional well permits.

8/4 to 8/10
MPCA updated as to the above findings, with various discussions as to plans and difficulties securing drill rig.

8/16/04
MPCA again updated as to efforts to secure a drill rig. Enbridge was finally able to retain WDC Exploration, and aim for the first week of September to begin drilling at the site again.

8/31/04
E-mail update to MPCA informing that drilling was to start.

9/7/04 - 9/9/04
Drillers mobilize and commence. Upgradient well installed by 9/9 (MW-2). No odors or oil staining identified as boring is advanced. Well is allowed to stabilize for later testing.

9/9/04 to 9/16/04
Drill rig in the shop until 9/13 to fix a hydraulic leak, drilling resumes 9/13, and a significant breakdown occurs five feet into drilling. MPCA updated 9/16, aiming for Monday, 9/20 to resume work.

9/20 to 10/11/04
Drilling occurs throughout this period, with several equipment breakdowns due to difficult rock/boulder conditions. MPCA updated 10/11/04, noting that as of October 8, five wells had been installed, with oil thickness as follows:

MW-1 = 15.6 inches
MW-2 = 2.3 inches
MW-3 = 1.2 inches
MW-4 = No product
MW-5 = No product

It was noted that oil thickness measurements in MW-1 and MW-2 had been consistent for a couple weeks, while MW-3 had been increasing and may not have had enough time to reach stable conditions.

10/22/04
Phone update provided to MPCA as to well installation progress.

11/03/04
McDonald's and Stemwedel's (2nd time) wells were sampled. Results did not show any impacts and results were communicated to them.

11/29/04
MPCA updated, noting again that progress had been difficult. MW-10 and MW-11 yet to be installed, but expectation is that these will be in place in the next week or so, equipment and weather permitting. Existing wells summarized as follows:

MW-1: Product present (~ 15.5")
MW-2: Product present (~ 2.5")
MW-3: Product present (~ 1.8")
MW-4: Strong odor (sheen observed)
MW-5: Product observed (~ 3.0")
MW-6: Slight odor detected, product not observed
MW-7: No odor detected, product not observed
MW-8: No odor detected, product not observed
MW-9: No odor detected, product not observed

MPCA is informed that once investigation is complete (i.e., MW-10 and MW-11 installed), all wells will be developed, surveyed, and sampled, with results to be provided in a remedial investigation report.

12/15/04
MPCA updated. Drilling complete, but unable to install MW-11 (a further upstream well) due to snow and slippery conditions. Analytical parameters and methods and sampling plans discussed, and Enbridge communicates schedule of next steps: 12/16-17 develop recent wells, and complete sampling for all ten. Week of 12/21 complete site survey and slug testing of wells (hydraulic conductivity, groundwater velocity). Week of January 10 complete confirmation well testing. End of February submit remedial investigation report and preliminary proposed cleanup plans.

12/16 and 12/17/04
Wells sampled.

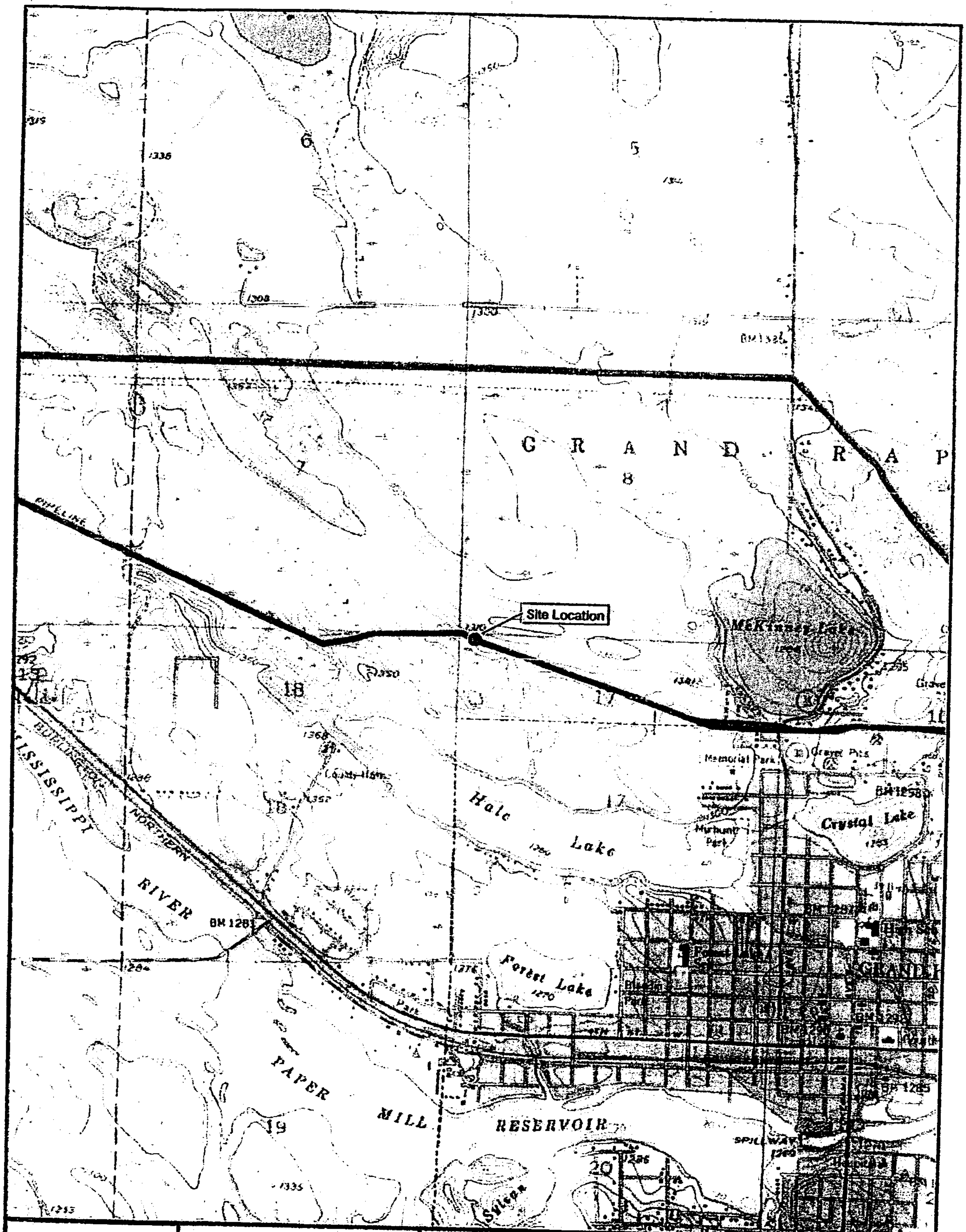
1/25/05
Second round completed. Free product stable in 3 or four wells, but had increased in MW-3.

1/31/05
Oil volume calculations received from consultant

2/4/05
Calculations checked, and scaling error discovered from the survey drawing. Oil volume recalculated; approximately 1,000 barrels.

2/7/05
OPS, MNOPS, MPCA updated

2/8/05
Follow-up discussion with MPCA to confirm plans, steps, and schedule.



ENBRIDGE

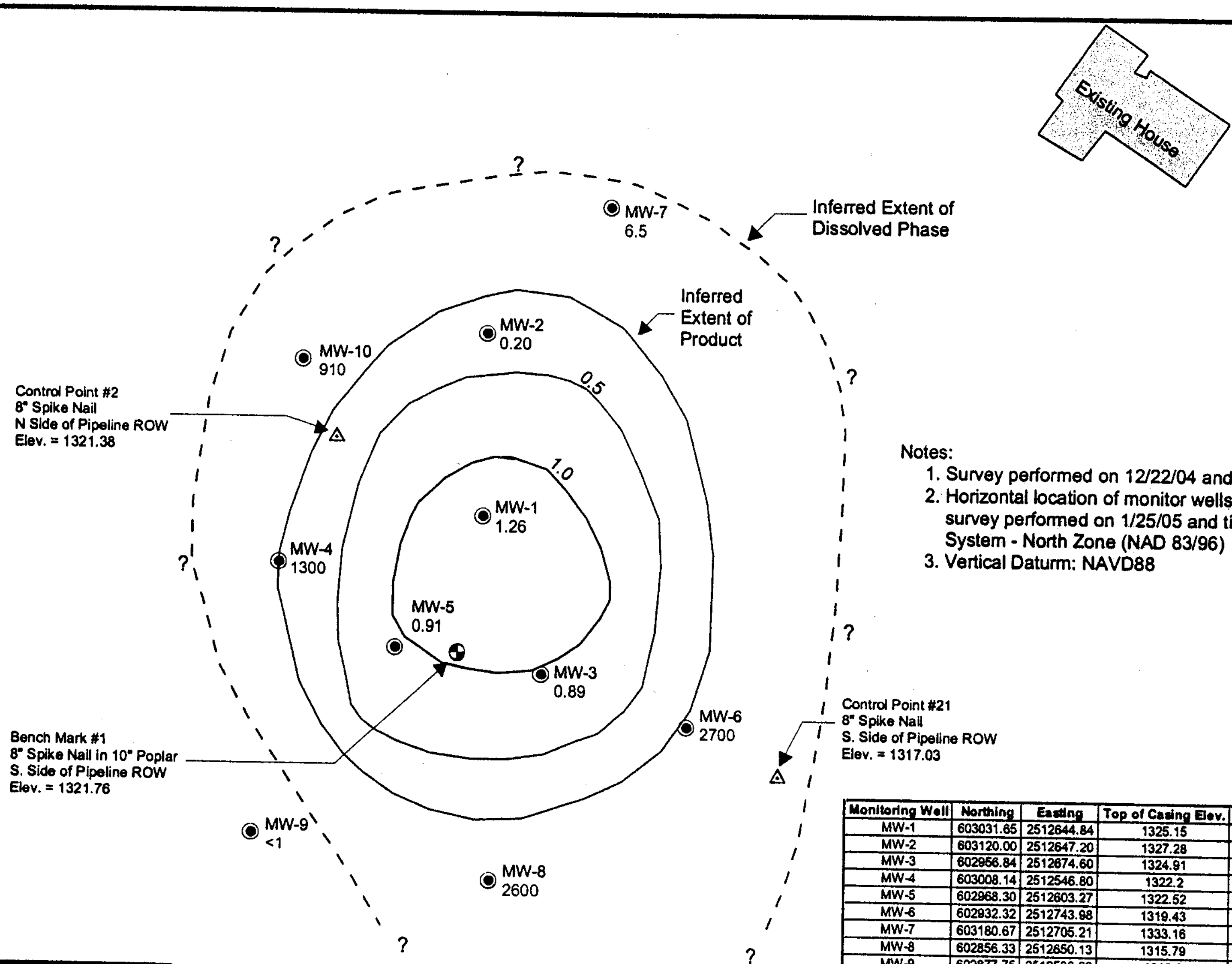
Legend

Site Location

Pipeline

Enbridge Pipelines (Lakehead), L.L.C.
Figure 1: Site Location Map

DATE ISSUED: 3/08/04	
DATE REVISED:	
SCALE: 1:24000	Resources
DRAWN BY: NREC	Engineering Co
SERIES: Grand Rapids	



Notes:
1. Survey performed on 12/22/04 and 1/25/05.
2. Horizontal location of monitor wells was derived from field survey performed on 1/25/05 and tied to the MN Coord. System - North Zone (NAD 83/96)
3. Vertical Daturm: NAVD88

Monitoring Well	Northing	Easting	Top of Casing Elev.	Ground Elev.	Description
MW-1	603031.65	2512644.84	1325.15	1322.54	North Rim
MW-2	603120.00	2512647.20	1327.28	1324.58	North Rim
MW-3	602956.84	2512674.60	1324.91	1319.24	North Rim
MW-4	603008.14	2512546.80	1322.2	1319.38	Ink mark, north rim
MW-5	602968.30	2512603.27	1322.52	1320.05	North Rim
MW-6	602932.32	2512743.98	1319.43	1317.13	North Rim
MW-7	603180.67	2512705.21	1333.16	1330.74	Ink mark, north rim
MW-8	602856.33	2512650.13	1315.79	1313.23	East Rim
MW-9	602877.75	2512536.28	1313.9	1311.41	Ink mark, north rim
MW-10	603105.04	2512557.79	1326.22	1323.72	Ink mark, north rim

MN State Plane N (ft)

Monitoring Well*
Product contour
Dissolved product contour

*Monitoring Well lables formatted as shown:
Name
Product thickness
Benzene concentration (12/17/04)

ENBRIDGE™

Enbridge Pipelines (Lakehead), L.L.C.

Grand Rapids, Minnesota (MP 1007.33)

DATE ISSUED: 2/3/2005
DATE REVISED:
SCALE: As Shown
DRAWN BY: NREC
FILE: Grand_Rapids_Product_Contour_Figure.pdf

Natural Resources Engineering Co.
715-395-5680

Attachment 3

In an attempt to assess how long oil may have been leaking from the pipe, groundwater modeling was conducted. Such modeling requires data for several variables, and ideally includes a number of groundwater sampling points, as well as multiple samples from each point to reduce the effects of variability. At the Grand Rapids site, there are substantial limitations in available data at this time. However, within these limitations and using the best available data at hand, our estimate is that the pipe had been leaking for approximately six years. This estimate was derived by inserting default values into the model as necessary to compensate for the limited amount of actual data currently available for use. Because of the limited data available, the actual length of time could be substantially different from the estimate.

Attachment #4

Enbridge Line 2 Leak History

Milepost	Date	Volume (Bbls)	Cause	Description
1074.5	07/24/55	300	Damage from rocks after pipe has been put into service	During construction, line was floated and lowered into ditch over a partly removed boulder. Settling caused rock penetration.
783.5	07/16/59	75	Operator Error or Other Incorrect Operation	Direct employee of operator
882	12/08/68	16,600	Defective pipe seam	Rupture in long weld apparently due to overpressure while swinging full rate into an idle line.
909.7	04/02/69	200	Defective girth weld	Hairline crack in weld.
855	03/12/72	200	Defective pipe seam	Small crack (1.25" long) in long weld.
1003.7	07/26/72	5400	Defective pipe seam	4" crack in long seam extending to girth weld.
828.4	08/13/73	17,001	Defective pipe seam	6' split in longitudinal seam.
897	09/11/73	4500	Defective pipe seam	9' long split in longitudinal seam.
823.8	06/03/74	5	Defective pipe seam	1.5" crack in longitudinal seam.
847.5	07/12/74	3	Defective weld	Small leak past sealing rubber of a 26" weld plus coupling.
817.5	07/29/74	20	Defective pipe seam - Hydrotest	10.4" split in longitudinal seam during hydrostatic test.
972	09/13/74	20	Defective pipe seam - Hydrotest	Long split in seam during hydrotest.
777	05/22/80	3	Defective girth weld	Pinhole leak at edge of longitudinal weld.
780.6	03/02/81	4	Defective pipe seam	1/2" crack in long seam.
776.5	12/19/81	117	Defective pipe seam	4" rupture in long seam.
848.2	10/30/86	1	Defective pipe seam	1/2" crack adjacent to long seam.
909.8	03/06/87	500	Defective pipe seam	1/2" crack in the long seam.

Enbridge Line 2 Leak History

Milepost	Date	Volume (Bbls)	Cause	Description
1056.2	04/09/89	100	Damage from rocks after pipe has been put into service	4' x 6' rock caused a 20" long by 2" deep dent and a 4" crack.
814.2	05/12/93	2	Third Party Damage (current or past)	A dent potentially caused by a backhoe caused small crack to develop.
1044.49	04/15/96	15	Defective fabrication weld or repair weld	2 cracks in side seam of pipe.
878.1	09/16/98	5700	Third Party Damage (current or past)	Third party excavation in the area.
957.1	02/23/00	10	Defective pipe seam	A pinhole leak on the longitudinal seam.
1007.33	02/19/04	10	Earth movement	Dent with metal loss determined from a tool run. Excavation indicated a rock had caused the dent and a small crack.

Attachment 5

The Enbridge 26-inch Line 2 was tested and put into service in this location in 1957. The most recent in-line caliper inspections at M.P. 1007.33 were performed in 1997, 2001, and 2003. In 1997 and 2001 the TDW Kaliper tool did not report a dent at this location. The contracted reportable dent threshold was a minimum depth of 2%. In 2003 the GE-PII MFL and Caliper inspections were performed. These tools reported a dent with metal loss, with a reported peak dent depth of 3.46%.

It is difficult to determine whether the rock that caused the dent was in contact with the pipe during initial construction or if natural mechanisms occurred which forced the pipe and rock together. Between 2001 and 2003 the ground was not disturbed in the immediate vicinity of the leak, and Enbridge is not aware of other external forces during this time frame that would cause pipe movement. For these reasons Enbridge believes that the increase in dent depth between 2001 and 2003 was caused by natural forces and reported soil subsidence on the Form 7000-1 report.

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust, Room 462
Kansas City, MO 64106-2641

NOTICE of PROBABLE VIOLATION
NOTICE of AMENDMENT
and
LETTER of CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 6, 2005

Mr. Dan C. Tutcher
President
Enbridge Energy Company, Inc.
1100 Louisiana
Suite 2950
Houston, TX 77002-7002

CPF No. 3-2005-5001

Dear Mr. Tutcher:

During the week of October 13, 2003, representatives of the Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an inspection of Enbridge Pipelines - North Dakota, LLC's (Enbridge-ND) HCA Management Plan at its facility in Minot, North Dakota.

As a result of the inspection, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The inspection found that Enbridge-ND had developed and implemented an integrity management program for pipeline segments that could affect high consequence areas (HCA) pursuant to §195.452. However, it appears that Enbridge-ND's written integrity management program must be amended to address the following items required by §195.452.

1. **§195.452 Pipeline integrity management in high consequence areas.**

   (f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:

2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

> **(c) What must be in the baseline assessment plan?**
> **(1) An operator must include each of the following elements in its written baseline assessment plan:**
> **(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.**

Enbridge-ND's pipeline system contains pre-70 ERW pipe, but Enbridge-ND considered this type of pipe not susceptible to longitudinal seam failure. A formal, documented, engineering analysis is necessary to support this determination to assure that appropriate assessment methods are chosen. Such an analysis was not available at the time of inspection.

2. **§195.452 Pipeline integrity management in high consequence areas.**

(f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

> **(h) What actions must an operator take to address integrity issues?**
> **(1) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with Sec. 195.422 when making a repair.**

A. Enbridge-ND utilizes some inline inspection (ILI) vendors under master agreements (i.e. contracts) which specify minimum performance requirements of the ILI tools. For those inline inspection vendors that are utilized outside of the master agreement(s), a minimum set of performance specifications, or a process to determine acceptable ILI vendor performance, needs to be developed in order for Enbridge-ND to properly discover anomalous conditions on its pipeline system.

B. Enbridge-ND's process for imposing required pressure restrictions needs to include means to limit over-pressurization by including the adjustment of shutdown setpoints, relief settings, and locking out equipment, etc. at the local level in addition to operating instructions issued at the Control Center. This is necessary to prevent inadvertent over-pressurization due to possible operator errors or communications failures.

3. **§195.452 Pipeline integrity management in high consequence areas.**

(f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(h) What actions must an operator take to address integrity issues?
(4) Special requirements for scheduling remediation.
(i) Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions.

(ii) 60-day conditions. Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(iii) 180-day conditions. Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

Enbridge-ND's HCA Management Plan referenced the use of magnetic flux leakage (MFL) inline inspection tools to detect deformation anomalies. In the absence of the use of a deformation tool to determine the size of pipeline dents, the process used to develop a remediation schedule must reflect the requirements to consider dent indications reported by the MFL tool vendor as actionable items meeting the repair conditions for dents listed under §195.452(h)(4)(i), (ii), and (iii). At the time of inspection, no baseline assessments had been completed; however, an MFL tool run had been completed where dent indications were examined and repaired as required.

4. **§195.452 Pipeline integrity management in high consequence areas.**

(f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
(3) Assessment intervals. An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

Enbridge-ND determined that the re-assessment intervals would be five years without adequate technical justification. The process to determine assessment interval should be technically justified and employ an analysis which supports that 5 year re-assessment is appropriate, as a shorter interval may be necessary based on risk factors, previous assessment results, and information analysis.

5. §195.452 Pipeline integrity management in high consequence areas.

(f) What are the elements of an integrity management program? An operator must include, at minimum, each of the following elements in its written integrity management program:
(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

A. **(i) What preventive and mitigative measures must an operator take to protect the high consequence area?**
(1) General requirements. An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area.

Enbridge-ND's HCA Management Plan did not include a process to analyze the risk, and determine preventive and mitigative measures for facilities (other than line pipe) that could affect an HCA in the event of a spill.

B. **(i) What preventive and mitigative measures must an operator take to protect the high consequence area?**
(3) Leak detection. An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors–length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

Enbridge-ND's HCA Management Plan did not have a sufficiently formalized process to evaluate the capability of the current means of detecting leaks and making modifications or improvements when necessary.

6. **§195.452 Pipeline integrity management in high consequence areas.**

(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:

(4) Include in the program a framework that--

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section;

Various elements of Enbridge-ND's integrity management program were to be carried out during the annual HCA review meeting. The process whereby this meeting is conducted needs to be fully developed and documented to assure that these required elements are implemented and supported with adequate technical justification for the decisions, analyses, and actions taken.

In regard to Items 1 through 6, when it is found that an operator's plans and/or procedures are inadequate the operator, after notice and opportunity for hearing as provided in 49 C.F.R. §190.237, may be required to amend its plans and procedures. This letter serves as your notification of inadequate plans and procedures as well as your response options as prescribed under §190.237. The operator is allowed thirty (30) days after receipt of such notice to submit written comments or request an informal hearing. After considering the material presented, OPS is required to notify the operator of the required amendment or withdraw the notice proposing the amendment. If you do not desire to contest the notice, within thirty (30) days of receipt of this notice you must prepare the revised procedures and provide a copy to:

Director, Central Region
Office of Pipeline Safety
901 Locust St, Room 462
Kansas City, MO 64106

In addition to the items noted above, the inspection revealed areas of concern that we would like to bring to your attention.

- Document retention requirements in the HCA Management Plan were general in nature. A listed set of necessary documents that supports the implementation of the integrity management program would be helpful in assuring that all necessary records are retained and available as needed.

- Some of Enbridge-ND's integrity management program elements are carried out by (e.g. segment identification) or follow other Enbridge companies' processes. These efforts and/or processes should be referenced by, or included in, Enbridge-ND's HCA Management Plan.

We appreciate your attention to these matters.

Please refer to CPF 3-2005-5001 in all correspondence related to this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 20, 2007

Mr. Terrance McGill
President
Enbridge Pipelines, LLC
1100 Louisiana
Suite 3000
Houston, TX 77002

CPF 3-2005-5001

Dear Mr. McGill:

During the week of October 12, 2003, representatives from the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of Enbridge Pipelines – North Dakota, LLC's (Enbridge-ND) integrity management procedures in Minot, North Dakota. As a result of the inspection, Enbridge-ND was issued a Notice of Amendment on January 6, 2005, which proposed amendment of your procedures.

Enbridge-ND submitted its amended procedures on February 11, 2005. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

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Tel 715 394 1534
Fax 715 394 1500
mark.willoughby@enbridge.com

ENBRIDGE™

February 11, 2005

Mr. Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust, Room 462
Kansas City, MO 64106-2641

CPF No. 3-2005-5001

Dear Mr. Huntoon:

In response to the Notice of Probable Violation, Notice of Amendment and Letter of Concern dated January 6, 2005, we offer the following comments:

1. **Enbridge-ND's pipeline system contains pre-70 ERW pipe, but Enbridge-ND considered this type of pipe not susceptible to longitudinal seam failure. A formal, documented, engineering analysis is necessary to support this determination to assure that appropriate assessment methods are chosen. Such an analysis was not available at the time of inspection.**

Response:
A formal, documented engineering analysis that addresses the susceptibility of EPND's pre-70 ERW pipe to long seam failure has been completed. Two (2) of the eight (8) line segments identified within Section 5.3 Facility Assessment, of the EPND HCA manual contain high frequency ERW pipe and are therefore not considered susceptible to cracking under the HCA ruling. The remaining six (6) line segments were reviewed in accordance with the flowchart titled Figure 4.1 in OPS TTO 5 as discussed below.

Three (3) of the six (6) segments were not considered to be susceptible to long seam cracking because their licensed normal operating pressure is less than 30% SMYS. One (1) segment was not considered to be susceptible to long seam cracking because its normal operating pressure is less than 30% SMYS. All segments not requiring a baseline assessment will undergo periodic review.

The remaining two (2) of the six (6) segments operate at a pressure greater than 30% SMYS. An engineering analysis was completed on the 16 inch diameter segment from Minot to Clearbrook, which represents over 50% of the total pipeline mileage being considered and traverses over 60% of the high consequence areas. This quantitative fatigue assessment was completed by Kiefner and Associates Inc. and it utilized detailed operating pressure data as well as material data from samples cutout of the pipeline. This assessment determined that a crack inspection is warranted on this pipeline segment. As a result, EPND has scheduled crack in-line inspection of this line segment for 2005. The remaining segment is the Lignite to Berthold Pipeline and consists of 1998 piping and 1962 piping. The 1962 portion of this line was not in active service from 1963 to 1991 and will undergo a quantitative crack assessment to confirm a need for baseline assessment. This assessment will be completed in 2005.

The HCA Management Plan and the Baseline Assessment Plan will be updated as appropriate to reflect this analysis.

2. **A. Enbridge-ND utilizes some inline inspection (ILI) vendors under master agreements (i.e. contracts) which specify minimum performance requirements of the ILI tools. For those inline inspection vendors that are utilized outside of the master agreement(s), a minimum set of performance specifications, or a process to determine acceptable ILI vendor performance, needs to be developed in order for Enbridge-ND to property discover anomalous conditions on its pipeline system.**

Response:
If an ILI vendor not covered by the master agreement were to be used the required performance specifications of the vendor and the tools would be included within the contract documentation. To clarify this process the HCA Management Plan will be revised as follows:

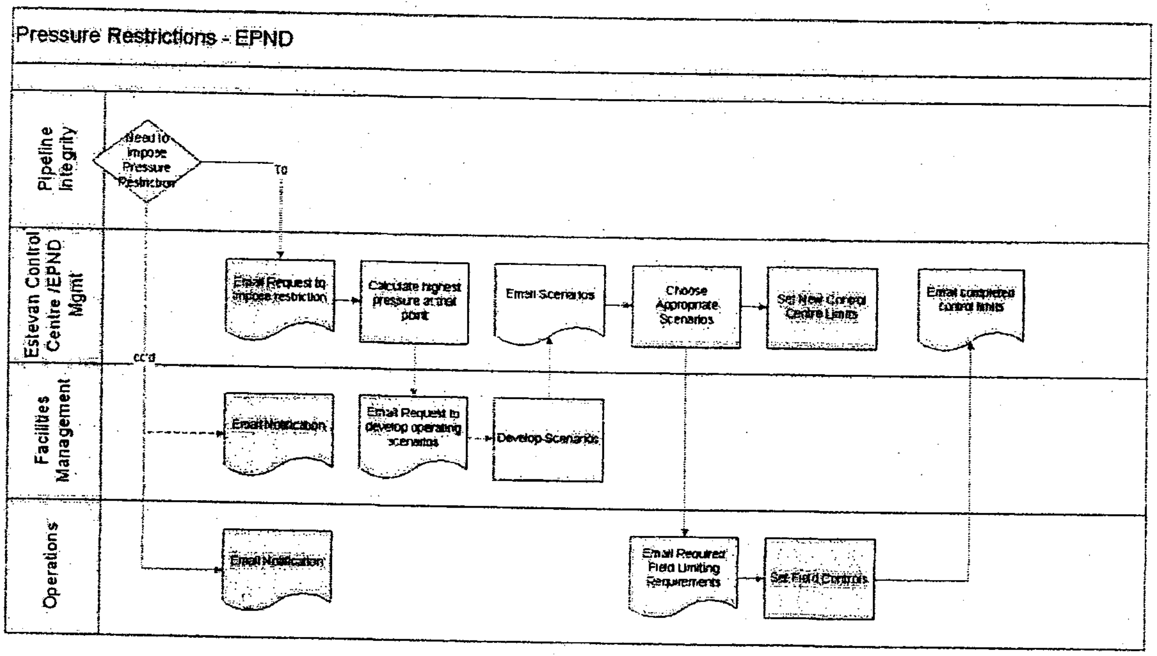
"Performance specifications for the ILI vendor and the vendor's tools are documented in the Enbridge ILI vendor master service agreement (master agreement). If an ILI vendor not covered by Enbridge's master agreement is to be used the required performance specifications of the vendor and the tools are to be included within the contract documentation."

Also, the process to ensure acceptable ILI vendor performance is detailed in Section C - Validation Process of the HCA Management Plan.

B. Enbridge-ND's process for imposing required pressure restrictions needs to include means to limit over-pressurization by including the adjustment of shutdown setpoints, relief settings, and locking out equipment, etc. at the local level in addition to operating instructions issued at the Control Center. This is necessary to prevent an inadvertent over-pressurization due to possible operator errors or communication failures

Response:
To clarify Enbridge North Dakota's communication process and setting of overpressure protection devices during a system pressure restriction, EPND will add the following language to the Operating and Maintenance Procedures Manual and reference the procedure in the HCA Management Plan:

"Following the identification of the need for a pressure restriction the following flow chart outlines the communication plan and process of setting overpressure devices."



3. **Enbridge-ND's HCA Management Plan referenced the use of magnetic flux leakage (MFL) inline inspection tools to detect deformation anomalies. In the absence of the use of a deformation tool to determine the size of pipeline dents, the process used to develop a remediation schedule must reflect the requirements to consider dent indications reported by the MFL tool vendor as actionable items meeting the repair conditions for dents listed under §195.452(h)(4)(i), (ii), and (iii). At the time of inspection, no baseline assessments had been completed; however, an MFL tool run had been completed where dent indications were examined and repaired as required.**

Response:
EPND will utilize either an MFL corrosion inspection tool or a deformation tool to locate possible dents and gouges.

If an MFL tool is utilized as the assessment method for deformations all dent indications that require remediation are treated as immediate repair conditions. As such, this process meets the requirements of §195.452(h)(4)(i), (ii), and (iii). The HCA Management Plan will be revised to include the following text to clarify the process:

"If an MFL tool is utilized as the assessment method for deformations all dent indications that require remediation will be treated as immediate repair conditions."

4. **Enbridge-ND determined that the reassessment intervals would be five years without adequate technical justification. The process to determine assessment interval should be technically justified and employ an analysis which supports that five year re-assessment is appropriate, as a shorter interval may be necessary based on risk factors, previous assessment results, and information analysis.**

Response:
At the time of the audit none of the pipelines had received baseline inspections and therefore reassessment intervals had not been finalized. Preliminary planning was captured in the Baseline Assessment Plan that showed reassessment intervals at five (5) years as per the regulatory requirements.

Once baseline information is obtained a fitness for purpose reassessment interval will be set in accordance with processes outlined in the Enbridge Corrosion Growth Rate Analysis and Corrosion Assessment Interval Program documents.

The HCA Management Plan will be revised to include the following text to clarify the process:

"Reassessment intervals for any given trap to trap segment are established through probabilistic means as described in the Enbridge Corrosion Growth Rate Analysis document and the Corrosion Assessment Interval Program document."

Additionally, the HCA Management Plan will be revised to remove the preliminary five (5) year re-assessment schedule and include the reassessment schedule for each pipeline as they are developed.

5. A. Enbridge-ND's HCA Management Plan did not include a process to analyze the risk, and determine preventive and mitigative measures for facilities (other than line pipe) that could affect an HCA in the event of a spill.

Response:
Development of a large-scale facility risk model began in 2004. Enbridge anticipates completing model development and validation in late 2005.

In the absence of a large-scale model, Enbridge utilizes small-scale models to assess specific risk factors at our facilities. In 2004 Enbridge developed a model to assess site containment risks at Enbridge ND facilities. This model was used to prioritize work at high-risk sites and to develop a multi-year program to manage the risk of containing a leak at these facilities. Results from the 2004 program will be incorporated into the large-scale risk model.

Enbridge expects to continue to utilize small-scale risk models as required to supplement facility risk assessments.

B. Enbridge-ND's HCA Management Plan did not have a sufficiently formalized process to evaluate the capability of the current means of detecting leaks and making modifications or improvements when necessary.

Response:
EPND has reviewed the current leak detection system and determined that in addition to the current leak detection practices involving pressure monitoring, flow rate trending techniques, and aerial patrols, a metered and software-based leak detection system will be added to enhance current leak detection capabilities. The first phase of the multi-year program entails

the installation of the improved leak detection system on the 16" Minot to Clearbrook pipeline in 2005, which comprises over 60% of the EPND HCA segments. The remaining segments will be completed within the program time frame, prioritized on HCA ranking and overall risk.

With the initial leak detection review complete and the implementation plan initiated, EPND will continue to evaluate leak detection capabilities and make modifications or improvements as necessary. This continual review process will be formalized and included in the HCA Management Plan.

6. **Various elements of Enbridge-ND's integrity management program were to be carried out during the annual HCA review meeting. The process whereby this meeting is conducted needs to be fully developed and documented to assure that these required elements are implemented and supported with adequate technical justification for the decisions, analyses, and actions taken.**

Response:
Many ongoing elements of the EPND HCA Management Plan are carried out during the annual review meetings. While most of these items are listed in the annual review checklists detailed in Section 5.8, the HCA Management Plan will be revised to more clearly state the actual processes used, including:

- Identification of meeting agenda items
- Information required in meeting minutes
- Action item Subject Matter Experts and associated completion time lines.
- The final location of the technical documentation used to support the decision making process
- Retention of options considered but not chosen for implementation

This revision will formalize the actions that are currently undertaken in the annual review process.

In addition to the above, we have addressed the following areas of concern, as noted in your letter:

- **Document retention requirements in the HCA Management Plan were general in nature. A listed set of necessary documents that supports the implementation of the integrity management program would be helpful in assuring that all necessary records are retained and available as needed.**

Response:
As EPND is now entering the third year of implementing the HCA Management Program, the Company's experiences to date are being utilized to develop a record retention system. A tabulation of necessary documentation is currently being created to detail the document title, responsible individual for ensuring the document is complete, as well as the location of the document. When this document retention system is completed, verbiage will be added to the HCA Management Plan that details the elements of the process.

- **Some of Enbridge-ND's integrity management program elements are carried out by (e.g. segment identification) or follow other Enbridge companies' processes. These efforts and/or processes should be referenced by, or included in, Enbridge-ND's HCA Management Plan.**

Response:
All elements and processes referenced in the HCA Management Plan that are defined in manuals or documents separate from the Plan will be identified by title where appropriate as well as listed on a separate page for general references. The location of these manuals and documents, as well as the custodian department or individual responsible for the maintenance of them, will also be listed on the general references page.

We trust that the above information sufficiently addresses all the concerns noted in your January 6, 2005 letter. Enbridge personnel have worked diligently to create a high quality program that effectively captures the intent of CFR §195.452. We are confident that the recently enacted procedures and work flow processes discussed above will strengthen our HCA Management Plan.

Should you have any further questions or concerns, please contact me.

Sincerely,

Mark J. Willoughby

c: Kevin Hatfield
Steve Irving
Brian Johnson
Art Meyer
Dan Tutcher
Leon Zupan