U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

September 25, 2014

VIA CERTIFIED MAIL AND FACSIMILE TO 403.920.2412:

Mr. Russell Girling
President and CEO
TransCanada Corporation
450 1st St SW
Calgary, Alberta T2P 5H1

Re: CPF No. 3-2014-1005H

Dear Mr. Girling:

Enclosed is a Corrective Action Order. It requires TransCanada Corporation's ANR Pipeline Company to take certain corrective actions with respect to its natural gas transmission system as a result of the rupture of the 22-inch natural gas transmission pipeline near Benton Harbor, Michigan, reported to the National Response Center on September 16, 2014 at 5:09 am, Eastern Daylight Time (EDT). Service is being made by certified mail and facsimile. Service of this Corrective Action Order by facsimile or other electronic means is complete upon transmission or receipt as provided under 49 CFR § 190.5. The terms and conditions of this Order are effective immediately upon service.

Thank you for your cooperation in this matter.

Sincerely,

for Jeffrey D. Weise
Associate Administrator
for Pipeline Safety

Enclosure

Cc: Ms. Linda Daugherty, Director, Central Region, OPS
Mr. Vern Meier, VP of Field Operations,
ANR Pipeline – 717 Texas Ave., Houston, TX 77002

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
ANR Pipeline Company , a subsidiary of TransCanada Corp.,)	)	**CPF No. 3-2014-1005H**
Respondent	)	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order (Order) is being issued, under the authority of 49 USC § 60112 and 49 CFR § 190.233, to require TransCanada Corporation's subsidiary ANR Pipeline Co. (TransCanada/ANR or Respondent) to take the necessary corrective action to protect the public, property, and environment from potential hazards associated with a recent rupture involving TransCanada/ANR's 22-inch natural gas transmission pipeline near Benton Harbor, Michigan.

On September 16, 2014, a failure occurred on Respondent's 22-inch diameter 0-100 Line at MP 933.59, approximately 1.4 miles east of the I-94 exit to Benton Harbor, Michigan, resulting in the release of an estimated 99.8 million cubic feet (MMCF) of natural gas into the atmosphere and the ejection of approximately fifty feet of pipe from the ground (Failure). The cause of the Failure has not yet been determined.

Pursuant to 49 USC § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the Failure. The preliminary findings of the ongoing investigation are set forth below.

Preliminary Findings

- ANR Pipeline Co., a subsidiary of TransCanada Corporation, owns and operates approximately 9,946.8 miles of natural gas transmission pipelines in Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nebraska, Ohio, Wisconsin, Kentucky, Mississippi, Tennessee, Arkansas, Louisiana, Oklahoma, and Texas, as listed in ANR Pipeline Co.'s 2013 annual report to PHMSA.

- The pipeline that failed is a 22-inch diameter steel pipeline referred to as the 0-100 Line. A 30-inch diameter steel pipeline referred to as the 1-100 Line runs parallel to the 0-100

Line, and is approximately 25 feet away at the failure location. The nearest compressor stations are the Bridgeman Compressor Station (MP 915.82) and the Hamilton Compressor Station (MP 977.5). For the purposes of this Order, the pipelines affected are TransCanada/ANR's 0-100 Line and the 1-100 Line between MP 915.82 and MP 977.5 ("Affected Segment"). The Affected Segment traverses Berrien, Van Buren, and Allegan Counties in Michigan. The Failure occurred in Berrien County, Michigan, near milepost 933.59.

- The Failure took place in a wooded area with creeks and farm ponds in close proximity. The specific area of the Failure is considered a Class 1 location. The nearest Class 2 locations are approximately 850 feet to the south, and 2700 feet to the north. The nearest Class 3 locations are 5100 feet to the north, and 2.7 miles to the south. The nearest High Consequence Area (HCA) is approximately 4700 feet to the north. The pipeline also crosses rivers and an interstate highway (I-94) near the Failure location.

- No ignition, fatalities, or injuries were reported as a result of the Failure. Approximately 550 people, reportedly comprising approximately 200 households, were evacuated as a result of the Failure, and nine roads were closed to limit access to the Failure location. Evacuated residents were permitted to return to their homes at 5:15 p.m. EDT on September 16, 2014.

- The 0-100 Line is currently isolated from Main Line Valve 61 (MP 931.72) to Main Line Valve 62 (MP 946.99), a distance of approximately 15.27 miles (Isolated Segment). TransCanada/ANR has reported to PHMSA that the 1-100 Line and the balance of the 0-100 Line within the Affected Segment have been reduced to a maximum discharge pressure of 724 psig at the Bridgeman Compressor Station. The pipelines are typically operated in common.

- According to TransCanada/ANR reports, the 0-100 Line in the area of the Failure was originally installed in 1949. It is 22-inch diameter with a wall thickness of 0.250 inches. The pipe is Grade X52 and has a flash-welded longitudinal seam with coal tar enamel and liquid epoxy coating. The pipe was manufactured by A.O. Smith. TransCanada/ANR has reported that a portion of pipe in the area of the Failure was replaced in 1960 following an in-service failure.

- Two pipeline fragments have been recovered, one approximately 30 feet in length and the other approximately 20 feet in length. Onsite observations appear to show the rupture was the result of longitudinally-oriented external cracking.

- According to information provided to PHMSA during the initial investigation, SCADA and pipeline instrumentation indicate that the failure occurred at 1:59 a.m. EDT. TransCanada/ANR's Gas Control received an external call at 2:45 a.m. EDT reporting un-odorized gas blowing at a very high pressure. The On-Call technician was dispatched by Gas Control at 2:50 a.m. EDT. The pipeline was equipped with automatic shutoff valves; however, only three of the four valves are reported to have closed as intended. The failed pipeline segment was reported to have been isolated from MP 931.72 to MP 946.99 at 4:50 a.m. EDT. TransCanada/ANR reported the incident to the National

Response Center (NRC) on September 16, 2014 at 5:09 a.m. EDT (NRC Report #1095426). PHMSA initiated an investigation of the incident, which involved an on-site investigation at the failure location by the Michigan Public Service Commission (PHMSA's agent for interstate natural gas pipelines in Michigan).The maximum allowable operating pressure (MAOP) of the pipeline at the Failure site was 850 psig. At the time of the failure, the actual operating pressure of the pipeline at the closest monitoring point to the failure location (Benton Harbor Meter Station) was 805 psig.

- The 1-100 Line within the Affected Segment is 30-inch diameter, and a majority of the pipeline was also manufactured by AO Smith. It has a flash-welded longitudinal seam. It is predominantly composed of 0.438-inch wall thickness Grade X-52 pipe and has a coal tar enamel coating. The 0-100 Line and the 1-100 Line are generally subject to the same environmental conditions.

- A Safety Related Condition Report (SRCR 20140045) was filed with PHMSA on May 1, 2014, by TransCanada/ANR for the segment of the 0-100 Line between the Sandwich, IL Compressor Station (MP 796) and the Bridgeman, MI Compressor Station (MP 915.82). The SRCR was related to seam-weld anomalies reported as a result of an EMAT In-line Inspection (ILI) tool run which necessitated pressure reductions.

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 CFR § 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.

After evaluating the foregoing preliminary findings of fact, I find that continued operation of the Affected Segment without corrective measures would be hazardous to life, property, and the environment. Additionally, having considered the nature of the Failure, the location of the Failure, the proximity of the Affected Segment to populated areas, rivers, an interstate highway, and other sensitive areas, the apparent malfunction of an automatic shutoff valve, and the nature of the product being transported, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in the likelihood of serious harm to life, property, or the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director of Central Region OPS, PHMSA (Director). If a hearing is requested, it will be held telephonically or in-person in Kansas City, MO or Washington, DC.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. In that event, 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 Actions

Pursuant to 49 USC § 60112, I hereby ORDER TransCanada/ANR to immediately take the following corrective actions regarding the Affected Segment:

1. ***Operation.*** Respondent must not operate the 0-100 Line between MP 931.72 and MP 946.99 (Isolated Segment) until authorized in writing to do so by the Director.

2. ***Operating Pressure Restriction.***

   a. Respondent must not operate the Affected Segment at a pressure greater than 80% of actual operating pressure at the time of the Failure. At the time of the failure, the pipeline was flowing from Bridgeman to Hamilton, but the line is capable of reverse operation. Submit the operating pressures for each compressor station on the Affected Segment at the time of failure and reduced discharge pressure limits for approval by the Director in the Restart plan referenced in Item 3. The pressure limits shall take into consideration both possible directions of flow (from Bridgeman to Hamilton and vice versa). This pressure restriction will remain in effect until written approval to increase or modify the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director pursuant to Items 5 and 6.

   b. Respondent may not operate any other portion of the 0-100 Line or the 1-100 Line at a pressure greater than the actual operating pressure at the time of the Failure.

   c. This pressure restriction is to remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director.

   d. Within 5 days of receipt of this Order, Respondent must provide the Director with the actual operating pressures of each compressor station and each main line pressure regulating station at the time of Failure and the documentation associated with the revised maximum pressure set-points at these same locations.

e. These pressure restrictions require any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly and documentation provided to the Director.

f. When determining the pressure restriction set-points, Respondent must take into account any ILI features or anomalies present to provide for continued safe operation while further corrective actions are completed.

g. Respondent must review the pressure restriction quarterly by analyzing operating data, including pressure and ILI data. ILI features or anomalies present in the Affected Segment must be reviewed, and operating pressure must be immediately reduced to maintain the safe operations of the Affected Segment. Results of the quarterly review must be submitted to the Director. The results must include, at a minimum, the current discharge set-point (including any additional pressure reductions) values per location, the highest experienced operating pressure and associated date for each location, and the total number of pressure exceedances during this time frame.

3. ***Restart Plan.*** Prior to resuming operation of the Isolated Segment, develop and submit a written Restart Plan to the Director for prior approval.

a. The Director may approve the Restart Plan incrementally without approving the entire plan, but the Isolated Segment cannot resume operation until the Restart Plan is approved in its entirety and implemented as approved.

b. Once approved by the Director, the Restart Plan will be incorporated by reference into this Order.

c. The Restart Plan must provide for adequate patrolling of the Isolated Segment during the restart process and must include incremental pressure increases during start-up, with each increment to be held for at least 2 hours.

d. The Restart Plan must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.

e. The Restart Plan must specify a day-light restart and include advance communications with local emergency response officials.

f. The Restart Plan must provide for a review of the Affected Segment for conditions similar to those of the Failure, including a review of construction, operating and maintenance (O&M) and integrity management records such as ILI results, hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations and pipe replacements. Respondent must address any findings that require remedial measures to be implemented prior to restart.

g. The Restart Plan must include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into Respondent's O&M manual.

h. The Restart Plan must provide for hydrostatic pressure testing within the Affected Segment in accordance with a written plan which must be approved by the Director.

4. ***Return to Service.*** After the Director approves the Restart Plan, Respondent may return the Isolated Segment to service in accordance with the Restart Plan, but the operating pressure may not exceed 80% of the actual operating pressure in effect immediately prior to the Failure in accordance with Item 2 above.

5. ***Removal of Pressure Restriction.*** The Director may allow the removal or modification of the pressure restriction upon a written request from Respondent demonstrating that restoring the pipeline to its pre-failure operating pressure is justified, based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating characteristics of the pipeline.

6. ***Modification of Pressure Restriction.*** The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from Respondent. Should this be requested, the written request will define other temporary mitigative and preventive measures that are to be implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the failure cause and provision of evidence that preventive and mitigative actions taken by the operator provide for the safe operation of the Affected Segment during the temporary removal or modification of the pressure restriction. After the temporary removal or modification is completed, documentation shall be provided to the Director substantiating other measures completed. Appeals to determinations of the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.

7. ***Instrumented Leakage Survey.*** Within 60 days of the receipt of this Order, Respondent must perform an aerial or ground instrumented leakage survey of the Affected Segment, using technology acceptable to the Director. Respondent must investigate all leak indications and remediate all leaks discovered. Respondent must submit documentation of this survey to the Director within 15 days of completion of this survey. Documentation related to remedial measures taken and associated completion dates must be submitted to the Director within 60 days of completion.

8. ***Records Verification.*** As recommended in PHMSA Advisory Bulletin 2012-06, verify the records for the Affected Segment to confirm the MAOP. Respondent must submit documentation of this record verification to the Director within 45 days of receipt of this Order and report any required changes or record discrepancies identified during this review.

9. ***Review of Prior ILI Results.*** Within 60 days of the receipt of this Order, Respondent must complete a review of any previous ILI results of the Affected Segment. Respondent must re-evaluate all ILI results from the past 10 calendar years, including a review of the ILI vendors' raw data and analysis. In the course of this review and re-evaluation, Respondent must determine whether any features were present in the failed pipe joint and/or any other pipe removed, and determine if any features with similar characteristics are present elsewhere on the Affected Segment. Report to PHMSA any wall thickness discrepancies found during the records reviewed. Respondent must submit documentation of this ILI review to the Director within 15 days of the completion of this Review as follows:

    a. List all ILI tool runs, tool types, and the date of the tool runs.

    b. List (describe type, size, wall loss, etc.) and identify the specific location of all ILI features present in the failed joint and/or other pipe removed.

    c. List (describe type, size, wall loss, etc.) and identify the specific location of all ILI features present elsewhere on the Affected Segment.

    d. Explain the process used to review the ILI results and the results of the re-evaluation.

10. ***Mechanical and Metallurgical Testing.*** Within 45 days of the receipt of this Order, complete mechanical and metallurgical testing and failure analysis of the failed pipe, including an analysis of soil samples and any foreign materials. Complete the testing and analysis as follows:

    a. Document the chain-of-custody when handling and transporting the failed pipe section and other evidence from the failure site.

    b. Within 10 days of receipt of this Order, develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.

    c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.

    d. Ensure the testing laboratory distributes all reports, whether draft or final, in their entirety to the Director at the same time they are made available to Respondent.

11. ***Root Cause Failure Analysis.*** Within 90 days following receipt of this Order, complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be supplemented/facilitated by an independent third-party expert acceptable to the Director and must document the decision-making process and all factors contributing to the cause or extent of the Failure. The RCFA must provide a detailed review of all SCADA and Controller activities that relate to the Failure. SCADA enhancements identified during this review shall be included in the report, which will include approximate timelines for implementation of such enhancements. Activities reviewed and summarized must include, but may not be

limited to: controller actions on the day before the Failure, the day of the Failure, and the day after the Failure; maintenance activities (same three days); automatic shutoff valve configuration, control operations, controller notes or logs (same three days); actual and calculated instrumentation readings (same three days); available communication statistics (same three days, including pressure and flow value poll times); other SCADA equipment functions (same three days); and SCADA maintenance requests and status (during the 6 months preceding the incident). The report should also include a review of 30 days of detailed pressure information to document any changes in operating conditions. The report should provide a specific summary regarding whether or not the controller(s) had adequate information to recognize and respond to abnormal operating conditions. If adequate information did not exist to recognize these conditions, identify enhancements for the SCADA system (display changes, added instrumentation, alarms, etc.) and controller activities that could provide the necessary data and allow for controller recognition. The final report must include findings, contributory factors, training considerations (if identified during the analysis), any lessons learned, and an identification of whether the findings and lessons learned are applicable to other locations within Respondent's pipeline system.

12. ***Emergency Response Plan and Training Review.*** Within 45 days of the receipt of this Order, Respondent must review and assess the effectiveness of its emergency response plan with regards to the Failure. Respondent must include in the review and assessment the on-scene response and support, coordination, and communication with emergency responders and public officials, as well as a review and assessment of the effectiveness of its emergency training program. Respondent must amend its emergency response plan and emergency training, if necessary, to reflect the results of this review. The documentation of this Emergency Response Plan and Training Review and any proposed corrective measures must be provided to the Director.

13. ***Integrity Work Plan (IWP).*** Within 90 days of the receipt of this Order, Respondent must submit an Integrity Work Plan (IWP) to the Director for approval.

    a. The Director may approve the IWP incrementally without approving the entire IWP.

    b. Once approved by the Director, the IWP will be incorporated by reference into this Order.

    c. The IWP must specify the tests, inspections, assessments, evaluations, and remedial measures Respondent will use to verify the integrity of the Affected Segment. It must address all known or suspected factors and causes of the Failure. Respondent should consider both the risk of another failure and the consequence of another failure to develop a prioritized schedule for IWP related work along the Affected Segment.

    d. The IWP must include a procedure or process to:

i. Identify pipe in the Affected Segment with characteristics similar to the contributing factors identified for the Failure.

ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the Affected Segment and to prepare a written report containing all the available information, such as the locations, dates, and causes of leaks and failures.

iii. Integrate the results of the metallurgical testing, root cause failure analysis, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the Affected Segment. Pre-existing operational data includes, but is not limited to, construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third-party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and DCVG/ACVG surveys.

iv. Determine if conditions similar to those contributing to the Failure are likely to exist elsewhere on the Affected Segment.

v. Conduct additional field tests, inspections, assessments, and/or evaluations to determine whether, and to what extent, the conditions associated with the Failure and other failures from the failure history (see [13(d)(ii)] above) or any other integrity threats are present elsewhere on the Affected Segment. At a minimum, this process must consider all failure causes and specify the use of one or more of the following:

1. ILI tools that are technically appropriate and sufficiently reliable for assessing the pipeline system based on the cause of the Failure,

2. Hydrostatic pressure testing,

3. Close-interval surveys,

4. Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g. underground utilities, overhead power lines, etc.) in the area,

5. Coating surveys,

6. Stress corrosion cracking surveys,

7. Selective seam corrosion surveys; and,

8. Other tests, inspections, assessments, and evaluations appropriate for the failure causes (such as soil analysis).

Note: Respondent may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have contributed to the Failure.

vi. Describe the inspection and repair criteria that will be used to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats, including a description of how any defects will be graded and a schedule for repairs or replacement.

vii. Describe, based on the known history and condition of the Affected Segment, the methods that will be used to repair, replace, or take other corrective measures to remediate the conditions associated with the Failure and to address other known integrity threats along the Affected Segment. The repair, replacement, or other corrective measures must meet the criteria specified in [13(d)(vi)] above.

viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the Affected Segment, considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.

e. Include a proposed schedule for completion of the IWP.

f. Respondent must revise the IWP as necessary to incorporate new information obtained during the failure investigation and remedial activities, to incorporate the results of actions undertaken pursuant to this Order, and/or to incorporate modifications required by the Director.

i. Submit any plan revisions to the Director for prior approval.

ii. The Director may approve plan revisions incrementally.

iii. Any and all revisions to the IWP after it has been approved and incorporated by reference into this Order will be fully described and documented in the CAO Documentation Report (CDR).

g. Implement the IWP as it is approved by the Director, including any revisions to the plan.

14. ***Quarterly Reports.*** Respondent must submit quarterly reports to the Director that include all available data and results of the testing and evaluations required by this Order and describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on January 15, 2015, and will cover the period from the Failure until December 31, 2014. Subsequent Quarterly Reports are due 15 days after the end of the applicable quarter. The Director may change the interval for the submission of these reports.

15. ***Documentation of Costs.*** It is requested but not required that Respondent maintain documentation of the costs associated with implementation of this Corrective Action Order. Include in each quarterly report the to-date costs and cost totals associated with each Item of this Order.

16. ***Approvals.*** With respect to each submission that under this Order requires the approval of the Director, the Director may (a) approve, in whole or in part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves of all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director and resubmit it for approval.

17. ***Extensions of Time.*** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.

18. ***CAO Documentation Report (CDR***). Respondent must create and revise, as necessary, a CAO Documentation Report (CDR). When Respondent has concluded all the items in this Order, it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by Respondent with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.

    a. The Director may approve the CDR incrementally without approving the entire CDR.

    b. Once approved by the Director, the CDR will be incorporated by reference into this Order.

    c. The CDR must include but not be limited to:

        i. Table of Contents;

        ii. Summary of the pipeline failure of Sept 16, 2014, and the response activities;

        iii. Summary of pipe data/properties and all prior assessments of the *Affected Segment*;

        iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;

        v. Summary of the Mechanical and Metallurgical Testing as required by the Order;

        vi. Summary of the RCFA with all root causes and contributory factors as required by the Order;

        vii. Documentation of all actions taken by TransCanada/ANR to implement the

IWP, the results of those actions, and the inspection and repair criteria used;

viii. Documentation of any revisions to the IWP including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;

ix. Lessons learned while completing this Order;

x. A path forward describing specific actions Respondent will take on its entire pipeline system as a result of the lessons learned from work on this Order; and

xi. Appendices (if required).

The actions required by this Corrective Action Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 CFR Part 192, under any other order issued to Respondent under authority of 49 USC § 60101 et seq., or under any other provision of Federal or State law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

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 USC 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 qualified for confidential treatment under 5 USC 552(b).

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 USC § 60120.

In your correspondence on this matter, please refer to CPF No. 3-2014-1005H. For each document you submit, please provide a copy in electronic format whenever possible.

The terms and conditions of this Corrective Action Order are effective upon receipt.

For Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

SEP 25 2014
Date Issued