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TransCanada Keystone Pipeline, LP

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Final Report No. 18-065

Root Cause Failure Analysis of Pipeline Rupture at Ludden +17

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to

TRANSCANADA KEYSTONE PIPELINE, LP

on

April 18, 2018

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ACRONYMNS

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CAO	Corrective Action Order
CFR	Code of Federal Regulations
CIS	Close Interval Survey
CP	Cathodic Protection
CPM	Computational Pipeline Monitoring
CRP	Conservation Reserve Program
CSA	Canadian Standards Association
DCVG	Direct Current Voltage Gradient
DOC	Depth of Cover
DOT	Department of Transportation (US)
DSAW	Double Submerged Arc Welded
EDS	Energy Dispersive X-ray Spectroscopy
EOC	Emergency Operations Center
ERP	Emergency Response Plan
FBE	Fusion Bonded Epoxy
GMAW	Gas Metal Arc Welding
HAZ	Heat Affected Zone
HCA	High Consequence Area
ICS	Incident Command System
ID	Inner Diameter
ILI	In-line Inspection
IMT	Incident Management Team
IST	Incident Support Team
LDS	Leak Detection System
MADP	Maximum Allowable Discharge Pressure
MDS	Multi Data Set
MFL	Magnetic Flux Leakage
MLV	Mainline Valve
MOP	Maximum Operating Pressure
MP	Milepost
MTR	Mill Test Report
NCR	Nonconformance Report
NDE	Nondestructive Examination
NRC	National Response Center
NTSB	National Transportation Safety Board
OCC	Oil Control Center
OD	Outer Diameter
O&M	Operations and Maintenance
PHMSA	Pipeline and Hazardous Materials Safety Administration
PICS	Pipeline Information Control System
POD	Probability of Detection
PSL	Product Specification Level
QA/QC	Quality Assurance/Quality Control
RCA	Root Cause Analysis
RCFA	Root Cause Failure Analysis
RCS	Resident Construction Supervisor
ROW	Right-of-Way
RTTM	Real-Time Transient Model
RWP	Remediation Work Plan
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SD DOT	South Dakota Department of Transportation
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
SPAC	Standards, Policies, and Administrative Controls
SD PUC	South Dakota Public Utilities Commission
TCPL	TransCanada Pipe Lines, Ltd.
US	United States
USGS	United States Geological Survey
UT	Ultrasonic
UTCD	Ultrasonic Crack Detection

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Root Cause Failure Analysis of Pipeline Rupture at Ludden +17

Stephanie Flamberg, Bruce Nestleroth, and Mike Rosenfeld (Kiefner and Associates)
Pieter van Wouw (TransCanada)

1 INTRODUCTION

A rupture occurred on November 16, 2017 on the Phase 1 Keystone 30-inch crude oil pipeline system operated by TransCanada Keystone Pipeline, LP (TransCanada) near MP 234.5, between 115th Street and 116th Street in Marshall County, SD. The location of the rupture is approximately 17 miles downstream of the Ludden Pump Station and as such is referred to as the Ludden +17 incident. The Phase 1 Keystone system, which operates from Hardisty, Alberta, Canada to Wood River and Patoka, IL, was originally built and hydrostatically tested in 2009 and commissioned into operation by TransCanada in June 2010. The rupture occurred when a fatigue crack initiated by mechanical damage reached its failure pressure during a routine pipeline cleaning tool run and internal leak inspection using SmartBall®. The initially reported release volume was 5,000 barrels of crude oil. The incident did not result in any injuries, ignition, or evacuation.

The release occurred in an area of northeastern South Dakota that is part of the conservation reserve program (CRP) where the land has been returned to its natural conditions for wildlife and public use. The topography in the area is relatively flat. The release was detected by TransCanada's oil control center (OCC) through its supervisory control and data acquisition (SCADA) system and leak detection system (LDS) in the early morning of November 16, 2017.

On November 28, 2017, PHMSA issued correction action order (CAO) CPF No. 3-2017-5008H outlining specific actions to be taken by TransCanada. Item 6 of the CAO specifies that TransCanada conduct a root cause failure analysis (RCFA) that includes findings and any lessons learned and whether the findings and lessons learned are applicable to other locations on the Keystone pipeline. This document is the report of the RCFA, in response to CAO Item 6.

2 BACKGROUND

2.1 Description of the System

2.1.1 Phase 1 Keystone Pipeline System

The Phase 1 Keystone pipeline system originates at Hardisty, Alberta, Canada and terminates at delivery points in Wood River and Patoka, IL. Phase 1 of the Keystone pipeline system was built between June 2008 and March 2010 by TransCanada using several different construction contractors, including [redacted], and [redacted][1].

The US portion of the Phase 1 Keystone pipeline consists of approximately 1,084 miles of 30-inch diameter pipe, 23 pump stations throughout North Dakota, South Dakota, Kansas, Missouri, and Illinois, a delivery facility in Patoka, IL, and related facilities that start at the Canadian border in North Dakota and terminate in Wood River, IL. Figure 1 shows a map of the Phase 1 Keystone Pipeline System.

Figure 1. Map of Keystone Pipeline System – Phase 1

[1] [redacted] [redacted] [redacted] have since merged and are later referred to as [redacted].

PHMSA issued a Special Permit on April 30, 2007 with 51 conditions to which Keystone Pipeline must adhere to allow the pipeline to operate at a stress level of 80% of the steel pipe's specified minimum yield strength (SMYS), whereas the Code of Federal Regulations (CFR) Title 49 Paragraph 195.106 normally limits the operating stress level for hazardous liquid pipelines to 72% of SMYS. The conditions within the Special Permit require TransCanada to more closely inspect and monitor the pipeline over its operational life than similar pipelines installed without a Special Permit.

2.1.2 Spread 2A

The failure occurred on the approximately 46.8-mile pipeline segment that runs between the Ludden Pump Station and Ferney Pump Station (affected segment) within construction Spread 2A. Spread 2A was constructed by [redacted] between May and November 30, 2008. As shown in Figure 2, Spread 2A is a 133.7-mile segment that originates in North Dakota just north of the Luver+7_4-A0 check valve on the west side of 121st Avenue SE (MP 129.9) and terminates at the Ferney Pump Station on the south side of County Road 22 (MP 263.6) in South Dakota. The pipe installed in this segment was manufactured by [redacted] and [redacted] in accordance with American Petroleum Institute 5L, Specification for Line Pipe, 43rd Edition (API 5L), product specification level 2 (PSL 2), double-submerged arc welded (DSAW) pipe, Grade X70. The pipe coating was mill applied fusion bonded epoxy (FBE) with field applied two-part epoxy at the girth welds. Field welds were made using automated gas metal arc welding (GMAW).

The maximum operating pressure (MOP) of the Keystone pipeline system prior to the failure was 1,440 psig (80% of SMYS). The MOP was established by a hydrostatic test performed June 26, 2009, as it pertained to the failure location and demonstrated conformance to the Special Permit conditions.

Spread 2A of the Keystone pipeline system has had multiple in-line inspections (ILI). Commissioning caliper runs were conducted in September 2009 and 2010. Combination caliper and magnetic flux leakage (MFL) tool runs were completed in 2012 and 2016. No excavations were conducted near the failure location as a result of the commissioning caliper, 2012 MFL and caliper, or 2016 MFL and caliper ILIs. In-line leak detection surveys ([redacted]) were also completed in 2015 and 2016. An in-line leak detection survey was ongoing at the time of the failure and had recently passed the failure location when the rupture occurred.

An as-built alignment map of the location where the rupture occurred is provided in Appendix A and shows the pipeline profile as well as the location of set-on weights, wetlands, streams, road crossings, and utility crossings. At the failure location, there were no stream, road, or utility crossings.

[redacted]

Figure 2. Map of Spread 2A

2.2 Synopsis of the Incident

On November 16, 2017, a rupture occurred on the 30-inch diameter Keystone Phase 1 Pipeline near MP 234.5 between the Ludden Pump Station and Ferney Pump Station releasing an initially reported volume of 5,000 barrels of crude oil. An aerial view of the release extent is shown in Figure 3. At 5:33 AM central time, the SCADA system indicated a pressure drop at the mainline valve 23.8 miles downstream of the Ludden Pump Station ([redacted]). One minute later, the LDS alarmed indicating a leak, the size of which exceeded the 400 m^3/hr detection threshold over a two minute averaging window. Immediately upon receipt of the leak alarm within the OCC, TransCanada's oil operations shut down the entire pipeline between Hardisty, Alberta and Cushing, OK[2] in accordance with standard procedures, isolated the affected pipeline

[2] On the day the release occurred, the line was operating toward Cushing, OK instead of Patoka, IL.

segment between Ludden Pump Station and Ferney Pump Station, and commenced emergency response activities.

During the field investigation, the Incident Management Team (IMT) discovered that the pipeline had ruptured at a feature indicative of mechanical damage (see Figure 4). The rupture initiated downstream of mill weld [redacted] in pipe joint number [redacted][3] (part of heat number [redacted]) but the running fracture crossed into the upstream joint before arresting (see Figure 5). A set-on concrete weight used for buoyancy control was located approximately three feet away from the initiation point. Upon confirmation of the release location, two stopple fittings were installed to isolate the damaged pipe for removal and replacement.

The affected segment was returned to active service at reduced pressure ([redacted] psig) on November 29, 2017 in accordance with the CAO and the restart plan as approved by PHMSA. The spool of pipe containing the rupture was sent to the National Transportation Safety Board (NTSB) for metallurgical evaluation. The residual of the spool removed with the failure feature was sent to Blade Energy Partners for additional analyses, if requested.

Figure 3. Aerial View of the Rupture Location

[3] The pipe joint number used throughout this report is the joint number as issued by the pipe mill.

Figure 4. Rupture Feature as Found In-the-Ditch. The set-on concrete weight is located on the right hand side of the photo.

Figure 5. Extent of the Failure Feature

2.3 PHMSA Corrective Action Order

On November 28, 2017, the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the US Department of Transportation (DOT) issued CAO CPF No. 3-2017-5008H outlining specific actions to be taken by TransCanada to understand the cause of the incident, verify that the causal condition does not exist elsewhere in the affected segment, and prevent recurrence of the incident in the future.

Item 6 of the CAO specifies that TransCanada conduct an RCFA. Root causes are deficiencies or gaps in management or control systems, such as procedures, training, communications, or procurement, to name a few, that allow a causal factor to occur or exist. The CAO stipulated that an independent third party be selected to supplement or facilitate the RCFA. Kiefner and Associates, Inc. (Kiefner) was selected to be the independent third party facilitator. Kiefner worked with TransCanada personnel representing pipeline construction, integrity, safety, operations, engineering, emergency response, and regulatory compliance as a team throughout the RCFA process.

The CAO stipulated that the RCFA must document the decision-making process used in the analysis and all factors contributing to the failure. Furthermore it must include findings and any lessons learned and whether the findings and lessons learned are applicable to other locations on the Keystone pipeline. The RCFA investigation team reviewed and evaluated data about the sequence of events, testing and examination of the failed pipe, the information available to company personnel, and decisions made prior to, during, and after the incident.

The CAO also required TransCanada to complete other activities, some of which provided important input to the RCFA:

- Item 3 required metallurgical analysis and testing of the failed pipe section by the NTSB. The findings of the NTSB investigation are discussed in Section 4.1.

- Item 4 required that TransCanada provide a remedial work plan (RWP) to verify the integrity of the affected segment and address all factors known or suspected in the failure including, but not limited to, a review of construction records, in-line inspection reports, and other pertinent data. In addition, TransCanada developed and is executing a plan to analyze available data on other weight locations for similar characteristics as the Ludden +17 failure, internally inspect the affected segment with technologies appropriate for identifying mechanical damage or crack indications, or both, with similar characteristics, and integrate this information with historical reviews, operational experience, the failure investigation, and RCFA to prevent recurrence.

3 RCFA PROCESS

3.1 Objective of the RCFA

An RCFA is an approach for identifying the underlying causes of why an incident occurred so that the most effective solutions can be identified and implemented to avoid a recurrence. The objective for this investigation was to determine what systems or equipment, or both, were insufficient resulting in the release of an initially reported volume of 5,000 barrels of crude oil from the Phase 1 Keystone pipeline.

3.2 RCFA Team

The investigation team consisted of the following personnel.

Kiefner	
Michael Rosenfeld, PE	Chief Engineer
Stephanie Flamberg	Principal Engineer
Bruce Nestleroth, PhD	Senior Principal Engineer
Fabian Orth, PhD	Senior Principal Engineer
TransCanada	
Pieter van Wouw, CRSP	Senior Safety Advisor
TransCanada (Contributors)	
[redacted]	Pipe Integrity Engineering
[redacted]	US Projects and Technical Services
[redacted]	Liquids Pipeline System Control

3.3 RCFA Methods and Scope

An RCFA is a structured approach to investigating an incident. The structure leads to examining all factors that could have affected the performance of equipment or personnel that led to the occurrence of the incident. A number of different methods have evolved for conducting an RCFA, e.g. a timeline analysis, a cause and effect tree, or a causal factor diagram (others exist which may be similar to the ones listed, with some minor differences in details or nomenclature). The RCFA team adopted the Cause and Effect Tree as described in a method developed by ABS Consulting.

The Cause and Effect Tree is an effective tool for incidents that involve multiple-event deficiencies. The technique looks back in time starting with the "loss event" (the incident) to describe what specific conditions had to be present or absent, or what events had to occur or not occur, in order for the incident to happen. Each of those factors is then examined to determine what prior conditions or events had to be necessary for it to exist. At each level, the following questions could be applied in order to attain a deeper understanding:

- Why did the event/condition occur?
- Given identified conditions, will the event always occur?
- Are there safeguards that could have prevented the event/condition?
- Are there other potential causes of the event/condition?

For each branch, each level must be supported or eliminated by data. Eventually, by eliminating particular lines of causes and effects based on data or analysis, the most probable or credible root causes can be identified. The process is complete when there is an understanding of the chain of events or conditions between one or more root causes and the event of interest. Identification of the root causes then leads to recommendations for improved safety and quality management systems.

The RCFA defines how the root cause(s) and contributing factors should be addressed to prevent recurrence of the incident. The outcomes of the Cause and Effect Tree process led to the conclusions and recommendations presented in this report.

The RCFA considered a detailed assessment of the following aspects related to the affected pipe segment:

1. Initial design and approval process
2. Construction methods, construction oversight, and quality management processes
3. Historical system operations, maintenance, and site influences
4. Integrity management and leak detection programs
5. Metallurgical analysis of the failure component

These five subject matter areas were considered within the scope of Item 6 in anticipation of PHMSA expectations, stated or implied, based on Kiefner's prior experience in conducting RCFAs ordered by PHMSA. Findings of the investigation were used to determine if there is a systemic nature to the incident at Ludden +17.

3.4 RCFA Terminology

Certain terms are commonly used with the RCFA process. These terms are defined below in order to improve interpretation of this report. These definitions are consistent with those in the ABS[4] process and methodology.

- Causal Factors are gaps in equipment or personnel performance that cause an incident or allow an incident to become worse. A causal factor may have one or more Root Cause.

[4] Definitions are derived from the ABS Consulting, Root Cause Analysis Handbook, Third Edition, 2008.

- Contributing Factors are underlying reasons why a causal factor occurred, but are not sufficiently fundamental to be a root cause.
- Root Causes are deficiencies of management or control systems, such as procedures, training, internal communications, or procurement that allow a causal factor to occur. A root cause must be within control of management to address.
- Items of Note are weaknesses discovered during the RCFA that are not directly related to the loss event, but if left uncorrected, could contribute to a future incident. Items of note represent potential opportunities for improvement.
- Barriers or Safeguards are systems or processes designed to avoid, prevent, or mitigate a failure or hazard, such as a specification or an inspection.

3.5 Event Timeline

A timeline was constructed to identify activities from the time of pipeline construction to the day the rupture occurred as well as actions to shut down the pipeline, isolate the release, and conduct initial response activities. The timeline presented in Table 1 is based on the PHMSA CAO data received from personnel interviews, construction documentation, inspection forms, operational logs, and emergency response forms.

Table 1. Event Timeline

Date	Time (CST)	Description	Source
April 30, 2007		• Special Permit issued to TransCanada for construction and operation of the Keystone Pipeline allowing the pipe to be operated at 80% of SMYS. • Special Permit contains 51 conditions requiring more frequent inspection and monitoring over the operational life of the pipeline.	• CAO
September 13, 2007		• TransCanada ordered the pipe used at the failure location in Spread 2A from Berg (order number [redacted]).	• Englevale ND Acceptance Report
June 2008 to March 2010		• Phase 1 of the 30-inch diameter Keystone pipeline was constructed.	• CAO

Date	Time (CST)	Description	Source
July 30, 2008 to August 4, 2008		• Heat number W8E596 from the Berg pipe mill was received at the Englevale, ND rail yard. • Visual inspection performed per Article 3.1 of the Line Pipe Witness Receipt Plan. • No damage noted on Daily Pipe Receiving Inspection Reports for railcars carrying pipe in heat number W8E596.	• Englevale ND Acceptance Report • Daily Pipe Receiving Inspection Report Acceptance
May 15, 2008 to December 9, 2009 (winter break December 2008 to May 2009)		• Spread 2A constructed by [redacted]. • 30-inch outer diameter (OD), API 5L, Grade X70 line pipe manufactured by Berg Steel Pipe Corporation. • DSAW seam with FBE factory applied coating.	• CAO
August 16, 2008		• Mowing of right-of-way (ROW); clear and dry conditions.	• Inspector's Utility Daily Report
September 30, 2008		• Pipe setup, bending, and line up. • 61 bends made.	• Pipe Setup, Bending, End Facing & Line Up Inspector's Daily Report
October 9, 2008		• Spread 2A pipe associated with the failure location was welded per WPS AP0053. • Cold and muddy.	• Integrity Assessment • Welding Inspector's Daily Report
October 9-21, 2008		• No other work completed at the failure location due to heavy rains.	• Integrity Assessment
October 21, 2008		• Spread 2A pipe associated with the failure location was coated with SPC SP-2888. • Overcast, light rain, cold, and blustery. • ROW was muddy, wet, and contained deep ruts.	• Integrity Assessment • Pipe Coating/Jeeping Inspector's Daily Report
November 7, 2008		• Jeeped and lowered in pipe associated with the failure location. • Sunny; muddy ROW conditions. • Installed mainline pipe trench with extra depth for concrete weights; sloughing of trench in water sands; staged weights from 116th street. • Cloudy, cold, windy; ROW was muddy and sticky.	• Lower-In/Tie-In Inspector's Daily Report • Trenching Inspector's Daily Report

Date	Time (CST)	Description	Source
November 8, 2008		• Spread 2A pipe associated with the failure location padded and backfilled.	• Padding/Backfill & Clean-Up/Restoration Inspector's Daily Report
January 2008 to February 2008		• Construction completed along a six-mile stretch of Spread 2A that was too wet originally. • Mileage not associated with the failure location.	• Witness Interview
January 22, 2009		• Keystone Emergency Response Plan (ERP) filed with the South Dakota Public Utilities Commission (SD PUC).	• South Dakota PUC Quarterly Report
February 12, 2009		• Keystone ERP approved by PHMSA.	• South Dakota PUC Quarterly Report
April 21, 2009 to May 6, 2009		• Hydrostatic test equipment calibrated (temperature recorder, pressure recorder, and dead weight tester).	• Mainline Pressure Test Report – Keystone Pipeline Project
June 22, 2009	10:30 AM	• Hydrostatic test of Spread 2A-4 MP 218.82 to 259.18 ([redacted] to [redacted]). • Test length: 40.38 miles. • Began filling test section.	• Mainline Pressure Test Report – Keystone Pipeline Project
June 24, 2009	1:00 AM	• Completed filling test section.	• Mainline Pressure Test Report – Keystone Pipeline Project
June 26, 2009	8:20 AM	• Began pressurizing test section.	• Mainline Pressure Test Report – Keystone Pipeline Project
June 26, 2009	1:00 PM	• Began yield plot for pressure test.	• Mainline Pressure Test Report – Keystone Pipeline Project
June 26, 2009	6:00 PM	• Completed yield plot for pressure test. • Maximum yield deviation was 0.007%. • Began 8-hour minimum pressure test period.	• Mainline Pressure Test Report – Keystone Pipeline Project

Date	Time (CST)	Description	Source
June 26, 2009	10:00 PM	• Ended strength test and started leak test. • Test pressure did not fall below 101.7% of SMYS or exceed 107% of SMYS.	• Mainline Pressure Test Report – Keystone Pipeline Project
June 27, 2009	11:30 AM	• Completed pressure test period. • Strength test pressure at high point: [redacted] psig (maximum); [redacted] psig (minimum) • Leak test pressure at high point: [redacted] psi (maximum); [redacted] psig (minimum) • MOP 1,440 psig • Tested according to 49 CFR 195 Subpart E, TransCanada Special Permit PHMSA-2006-26617, and TransCanada Specification KPP-901.	• Mainline Pressure Test Report – Keystone Pipeline Project
July 17, 2009		• Integrity management plan (IMP) submitted to PHMSA.	• South Dakota PUC Quarterly Report
August 7, 2009		• IMP submitted to SD PUC.	• South Dakota PUC Quarterly Report
September 2-3, 2009		• Construction caliper survey (TD Williamson) conducted from MP 218.5 to MP 259 ([redacted] to [redacted]). • Detected 1 bottom dent at MP 256.6, 0 ovalities, 0 expansions, 0 heavy welds. • Caliper grading specifications were 1% dent and 5% ovality. • Caliper survey conducted in accordance with Keystone Project Specifications, Contract #5180, Exhibit F Rev 11: Section 27 and KPP-901 Rev 5.	• Kaliper 360 Survey Report
September 26, 2009		• Final grade activities conducted at the location associated with the release. • Removed 30 mats from 116th Street to 115th Street. • Sunny; wet ROW conditions; abnormal conditions affected construction progress; crews affected by adverse weather, ROW, or other working conditions.	• Assistant Chief Inspector's Daily Report

Date	Time (CST)	Description	Source
October 13, 2009		• Spread 2A near the failure location seeded for CRP.	• Unit Price Pay Item/As-Built Report
2010		• Rosen caliper tool was run through piggable segment KS6 Fort Ransom to Freeman. • No geometry features identified near the failure location.	• Integrity Assessment
June 30, 2010		• Original in-service date of the Phase 1 Keystone pipeline.	• As-built Alignment Sheet
October 30, 2010		• Close Interval Survey (CIS) and Direct Current Voltage Gradient (DCVG) survey conducted. • Lowest cathodic protection (CP) OFF potential measured within 500 feet of the release location was 1,114 mV. • A 2% IR DCVG indication was found directly over the location of the failure feature.	• Integrity Assessment • PICS[5] Screen Capture
December 26, 2010		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,100 mV.	• PICS Screen Capture
December 26, 2011		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,150 mV.	• PICS Screen Capture
June 22, 2012		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,100 mV.	• PICS Screen Capture
2012		• ILI using Baker Hughes high resolution MFL/Caliper tool (Gemini). • No external metal loss in excess of 10% WT in depth or with failure pressure ratio (FPR) less than 1.42 within 500 feet of the failure location. • One internal metal loss feature (13% deep, 0.9-inch long, FPR = 1.42) within 500 feet of the failure location. • No geometry features identified near the failure location.	• Integrity Assessment

[5] Pipeline Information Control System (PICS) which is the application and associated database whereby the various integrity datasets are spatially normalized, integrated, and visualized.

Date	Time (CST)	Description	Source
June 8, 2013		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,000 mV.	• PICS Screen Capture
January 23, 2015		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,050 mV.	• PICS Screen Capture
June 26, 2015		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,050 mV.	• PICS Screen Capture
November 5, 2015		• SmartBall® inspection in piggable section KS6. • No leaks identified.	• Integrity Assessment
May 2016		• ILI using GE's high resolution MFL/Caliper tool (MFL4) in piggable section KS6 Fort Ransom to Freeman. • No metal loss (internal or external) in excess of 10% WT in depth or with FPR less than 1.42 within 500 feet of the failure location. • There is a 7% external metal loss feature (1.4-inch long x 2.1 inch-wide) coincident with the 2% IR call from the 2010 DCVG survey. • No geometry features identified near the failure location.	• Integrity Assessment
May 6, 2016		• SmartBall® inspection in piggable section KS6. • No leaks identified.	• Integrity Assessment
June 24, 2016		• Annual CP test lead survey between Ludden and Ferney Pump Stations. • All CP OFF potentials above -1,000 mV.	• PICS Screen Capture
October 2016		• MOP for the pipeline segment from the Canadian border to the suction side of Roswell Pump Station was increased to 1,440 psig ([redacted] kPa; 0.8 design factor).	• SCADA Review
February 8, 2017		• Highest pressure recorded at [redacted] 2017 – [redacted] psig ([redacted] of SMYS).	• DSS Pressure and Temperature Export

Date	Time (CST)	Description	Source
August 18, 2017		• [redacted] • [redacted]	• Witness Interview • DSS Pressure and Temperature Export • SCADA Review
November 3, 2017		• Aerial patrol of the Ludden +17 area. • No indications of leaks, third party activity, or other conditions.	• Integrity Assessment
November 8, 2017		• [redacted] and MADP increased back to 1,440 psig (0.8 design factor) downstream of the Ludden Pump Station.	• DSS Pressure and Temperature Export • SCADA Review
November 15, 2017		• SmartBall® inspection in piggable section KS6.	• Integrity Assessment
November 16, 2017		• Cleaning tool and SmartBall® passed the failure location without indicating any leaks.	• CAO
November 16, 2017	5:03 AM	• The control room began working off units at FERNY for SmartBall® and cleaning pig run.	• Integrity Assessment
November 16, 2017	5:24 AM	• FERNY placed in BYPASS mode for cleaning pig and SmartBall® run.	• Integrity Assessment • Incident Response and Isolation Plan
November 16, 2017	5:30 AM	• Cleaning tool 8 miles upstream of Ferney Pump Station (MP 256). • SmartBall® 18 miles upstream of Ferney Pump Station (MP 246).	• Incident Event Log
November 16, 2017	5:33 AM	• Keystone SCADA system detected pressure drop at LUDDE_+23-8.	• CAO • Integrity Assessment • Incident Response and Isolation Plan
November 16, 2017	5:34 AM	• Pressure drop indication at FERNY. • LDS alarm LUDDE-CRPTR 2 min 2,004 m^3/hr at 1,626 +/- 36 km – short. • LUDDE pump station low suction alarm and unit 2 SDR.	• Integrity Assessment • Incident Response and Isolation Plan
November 16, 2017	5:36 AM	• TransCanada control center initiated shutdown and isolation of the pipeline. • Leak flow peak = 8,534 m^3/hr.	• CAO • Integrity Assessment

Date	Time (CST)	Description	Source
November 16, 2017	5:40 AM	• First responders notified.	• Incident Response and Isolation Plan
November 16, 2017	5:44 AM	• LUDDE/FERNY/CRPTR sectionalized. • OCC on-call.	• Integrity Assessment • Incident Response and Isolation Plan
November 16, 2017	5:45 AM	• [redacted] closed. • [redacted] closed. • [redacted] closed.	• Integrity Assessment • Incident Response and Isolation Plan
November 16, 2017	5:46 AM	• [redacted] sectionalized. • [redacted] closed.	• Incident Response and Isolation Plan
November 16, 2017	5:48 AM	• [redacted] closed.	• Incident Response and Isolation Plan
November 16, 2017	5:48 AM	• [redacted] closed.	• Incident Response and Isolation Plan
November 16, 2017	5:56 AM	• Regional EOC notified.	• Incident Response and Isolation Plan
November 16, 2017	6:03 AM	• Canadian EOC notified.	• Incident Response and Isolation Plan
November 16, 2017	6:15 AM	• US regulatory compliance notified.	• Incident Response and Isolation Plan
November 16, 2017	6:18 AM	• Oil scheduling notified.	• Incident Response and Isolation Plan
November 16, 2017	6:25 AM	• Canadian regulatory compliance notified.	• Incident Response and Isolation Plan
November 16, 2017	6:38 AM	• Activated aerial patrol to fly over the affected segment.	• Incident Event Log
November 16, 2017	7:29 AM	• Everbridge notification was sent out by the Regional EOC.	• Incident Event Log
November 16, 2017	8:03 AM	• First responder arrived at [redacted] MLV; confirmed the valve was closed and there were no signs of oil. • Began heading north toward Ludden Pump Station.	• Incident Response and Isolation Plan • Incident Event Log
November 16, 2017	8:23 AM	• First responder arrived at Ludden Pump Station; no signs of oil. • Began heading south toward Ferney Pump Station.	• Incident Event Log
November 16, 2017	8:57 AM	• First responder reported odor between 115th Street and 116th Street; approximately MP 234.	• Incident Response and Isolation Plan
November 16, 2017	9:16 AM	• First responder confirmed oil on the ground LAT: 45.7078; LONG: -97.8768. • Time of discovery per section 195.52 of O&M procedure.	• Incident Response and Isolation Plan • Incident Event Log

Date	Time (CST)	Description	Source
November 16, 2017	10:17[6] AM	• Incident reported to the NRC (NRC Report No. 1197446). • Release of an initially reported volume of 5,000 bbls.	• NRC Database
November 16, 2017	11:02 AM	• State regulatory notifications completed.	• Incident Event Log
November 16, 2017	11:10 AM	• One-mile perimeter established around release site. • Fire Department and EMS onsite.	• Incident Event Log
November 18, 2017	11:25 AM	• Updated report provided to the NRC indicating no change (NRC Report No. 1197610).	• CAO
November 23, 2017	3:43 PM	• First observation of the top of pipe at the rupture location; rupture in close proximity to a weight.	• Incident Event Log
November 23-25, 2017		• Installing stopples upstream and downstream of rupture location.	• Incident Event Log
November 26, 2017		• TransCanada excavated failed pipe section and metallurgists identified a rupture originating near the 12:00 clock position. • Rupture had characteristics of mechanical damage. • Rupture near a concrete weight (installed in 2008) used for buoyancy control.	• CAO
November 28, 2017		• CAO CPF No. 3-2017-5008H issued to TransCanada Corporation.	• CAO
November 29, 2017		• Pipeline segment returned to active service.	• Integrity Assessment
December 14, 2017		• Inspection of KS5 (Elm Creek to Fort Ransom) with [redacted].	• Integrity Verification and Remedial Work Plan
December 19, 2017		• Inspection of KS6 (Fort Ransom to Freeman) with [redacted].	• Integrity Verification and Remedial Work Plan
Q1 2018		• Inspection of KS6 (Fort Ransom to Freeman) with [redacted].	• Integrity Verification and Remedial Work Plan

6 In the documents reviewed, some discrepancies were found in the actual time that TransCanada reported the incident to the NRC. The time reported in the NRC database was used as the official time.

3.6 Root Cause Event Tree

The loss event was defined as: rupture of pipe joint 857504 leading to the release of an initially reported volume of 5,000 barrels of crude oil. Causal factors were recognized for event sequences pertaining to (1) mechanical damage to the pipe joint and (2) the damage to the pipe joint remaining undiscovered. Contributing factors were identified related to the damage growing to a point of failure. The investigation also evaluated the control room response and pipeline isolation which limited the volume of the release. The incident Cause and Effect Trees are shown in Figure 6, Figure 10, Figure 29, Figure 39, and Figure 47 and are discussed in the following sections.

The events are color coded to aid interpretation as follows:

- Light blue = Events or steps in event sequence;
- Orange = Inconclusive: causes or causal factors that are neither confirmed nor eliminated by available data or evidence;
- Yellow = Eliminated: causes or causal factors that are eliminated by available data or evidence;
- Purple = Confirmed but not a factor: causes or causal factors that are confirmed as factual but determined to not be causal;
- Aqua = Unconfirmed but not a factor: neither confirmed nor eliminated by available data or evidence, but determined to not be causal.
- Light green = Confirmed: causes or causal factors that are confirmed by available data or evidence;
- Dark green = Root cause: conditions that are confirmed as root causes or near-root causes.

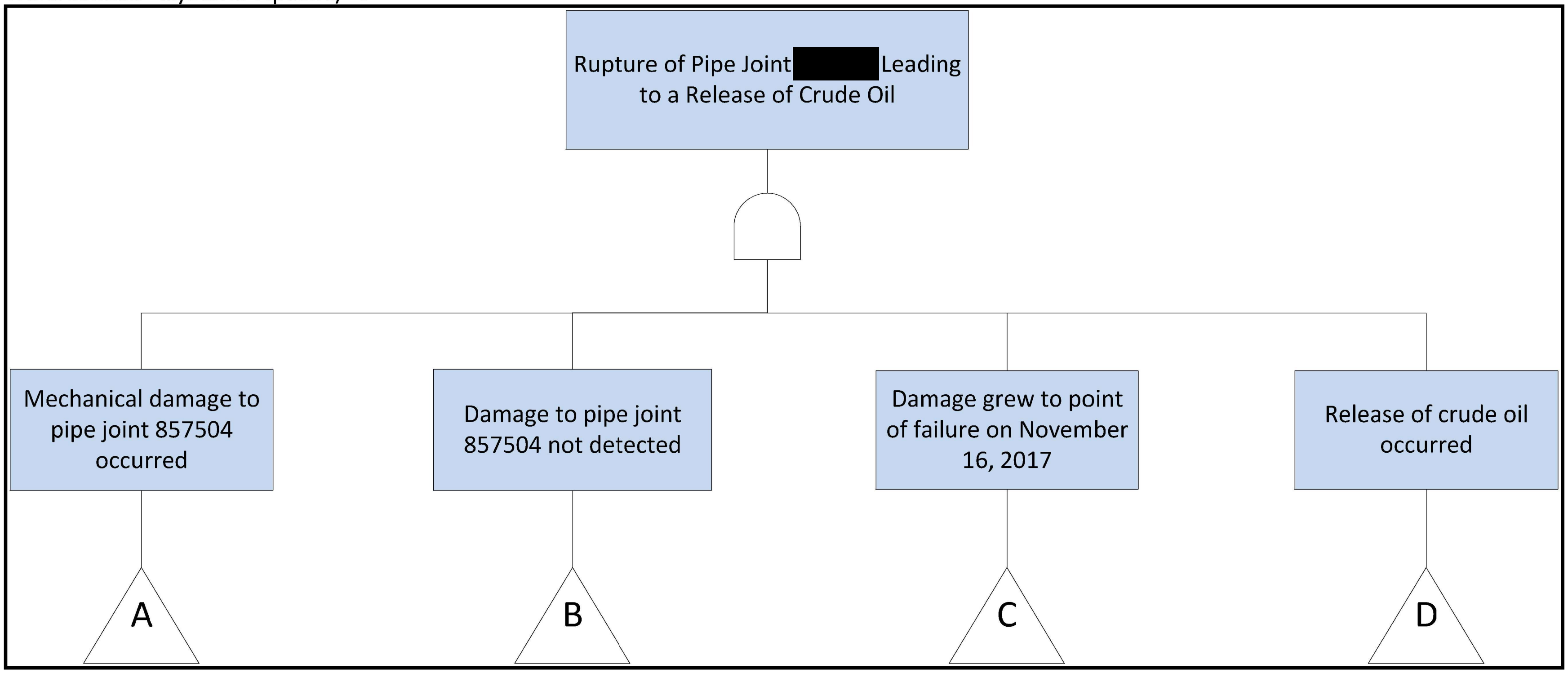

Figure 6. Pipe Rupture and Crude Oil Release - Root Cause Analysis Cause and Effect Tree

3.6.1 Mechanical Damage to Pipe Joint 857504 Occurred Event Sequence

According to the NTSB metallurgical analysis[7], the rupture initiated at near-surface cracks that formed within a sliding contact mark on the OD pipe surface (see Figure 7). Fatigue features including ratchet marks and curving crack arrest marks emanated from the near-surface crack boundary indicating that fatigue crack growth led to the failure.

Figure 8 shows the overall extent of the mechanical damage feature which extends on both sides of the fracture. The sliding contact marks were mostly aligned parallel to the longitudinal axis of the pipe and extended nine inches upstream and 21.5 inches downstream of the girth weld. The width of the sliding contact area measured up to 3.5 inches wide counterclockwise of the fracture location. As shown in Figure 8 and Figure 9, linear abrasions on the surface of intact coating were observed at the downstream end of the sliding contact marks. Coating material was present intermixed with the sliding contact marks and many edges of the remaining coating adjacent to individual contact marks were curled and rounded consistent with sliding contact deformation.

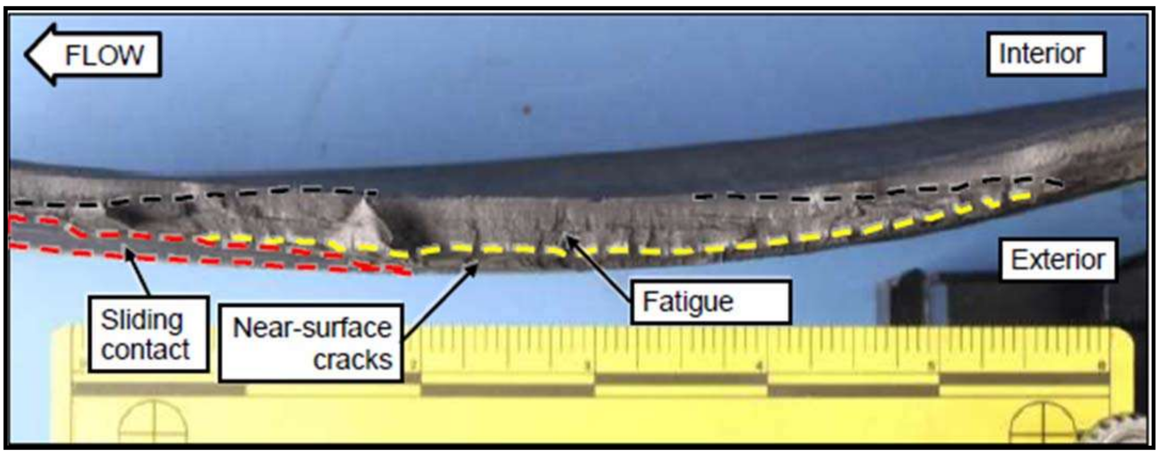

Figure 7. Extent of Failure Feature

[7] NTSB Report No. 18-017, Draft Materials Laboratory Factual Report, February 13, 2018.

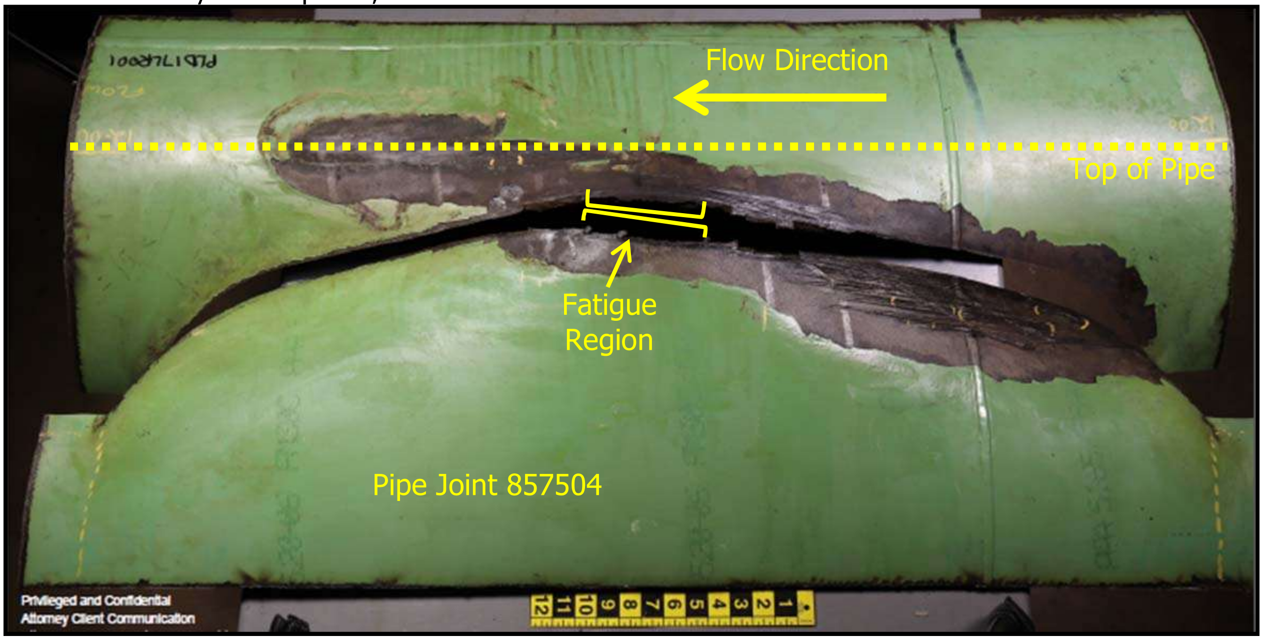

Figure 8. Mechanical Damage Feature between 11:00 and 12:00 Clock Position. The bracketed area indicates the fatigue crack region.

Figure 9. Close Up of Mechanical Damage Feature

Several possible sequences of causes and effects were postulated to have contributed to the occurrence of mechanical damage on pipe joint 857504:

- Mechanical damage occurred at the pipe mill (Eliminated)
- Mechanical damage occurred during pipe shipping, receiving, or storage (Eliminated)
- Mechanical damage occurred during pipe installation (Causal Factor)
- Mechanical damage occurred during operations (Eliminated)

The Cause and Effect Tree for the pipe mechanical damage sequence is shown in Figure 10 followed by an analysis of potential causal factors and root causes.

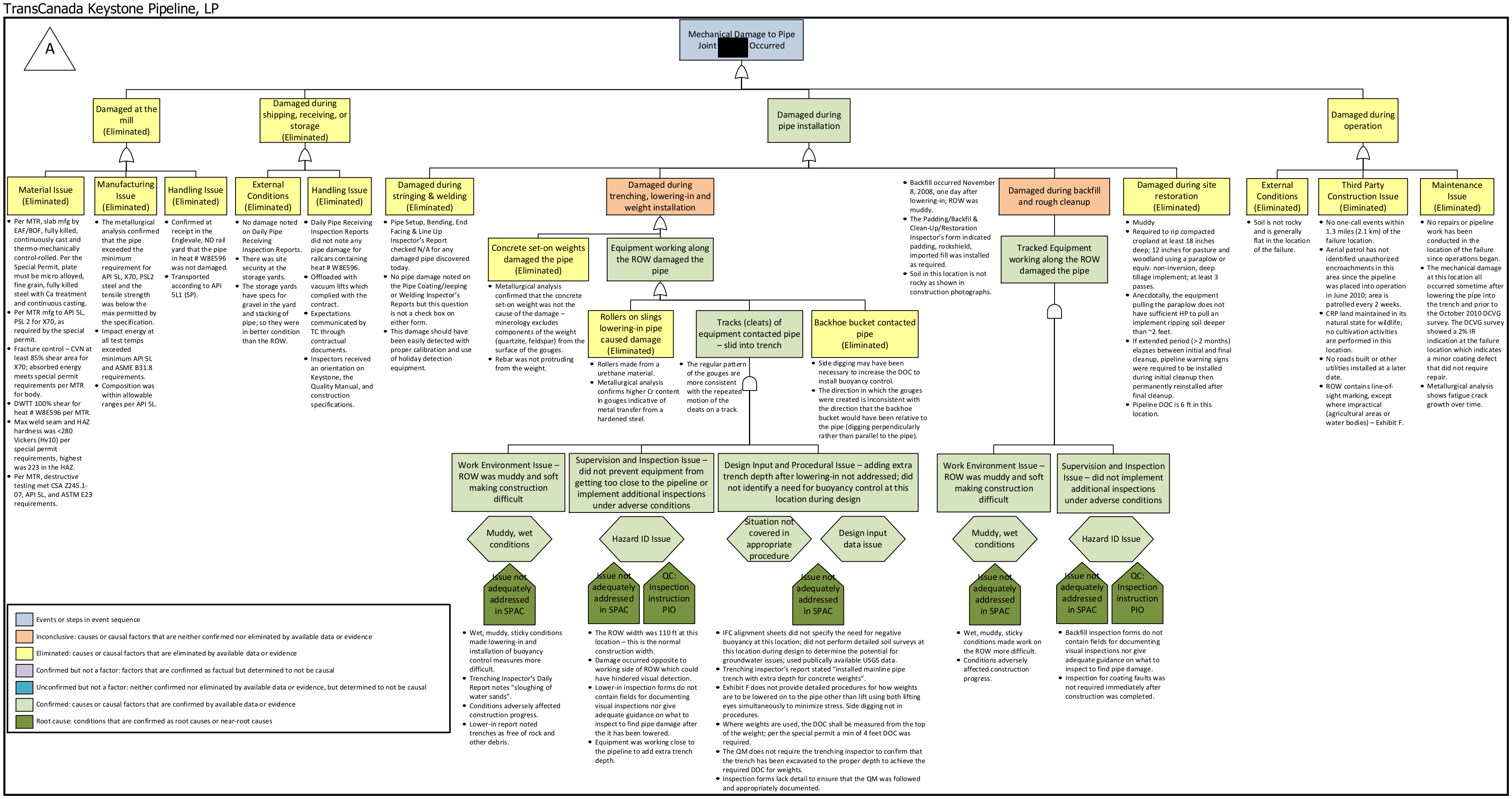

Figure 10. Mechanical Damage to Pipe Joint 857504 Occurred Event Sequence - Cause and Effect Tree

3.6.1.1 Damage Occurred at the Pipe Mill (Eliminated)

Several factors during pipe manufacturing could possibly have caused the type of mechanical damage found at Ludden +17 including, but not limited to:

- Pipe material strength issues that made the pipe more susceptible to failure from mechanical damage (Eliminated)
- Issues with the pipe manufacturing process that damaged pipe joint 857540 (Eliminated)
- Handling issues at the mill or during transport that led to damage of pipe joint 857540 (Eliminated)

The investigation determined that the mechanical damage occurred after the pipe had been received at the Spread 2A construction site which eliminates any potential for damage to occur at the mill. However, the team did investigate whether the pipe material strength could have made it more susceptible to failure.

On April 30, 2007 PHMSA granted TransCanada Keystone Pipeline, LP (Keystone) a waiver of compliance from pipeline safety regulation 49 CFR 195.106 through the issue of a Special Permit[8]. The regulation limits the design factor and operating stress level for hazardous liquid pipelines to 72% of SMYS (0.72 design factor). The Special Permit allows Keystone to establish an MOP for rural portions of the Keystone Phase 1 pipeline using a 0.80 design factor in lieu of the 0.72 regulatory maximum, with conditions and limitations as defined in the Special Permit.

Specific to manufacture of the pipe, the Special Permit required:

- the plate to be micro-alloyed, fine grain, fully killed steel with calcium treatment and continuous casting;
- the pipe to be manufactured according to API 5L, PSL 2, supplementary requirements (SR) for MOP and minimum operating temperatures;
- pipe carbon equivalents to be at or below 0.23% based on the material chemistry parameter (Pcm) formula;
- Keystone to institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation, including acceptable Charpy impact and drop weight tear test (DWTT) values (85% minimum average shear area for Charpy Impact and 80% minimum average shear area for DWTT) over the entire range of pipeline operating conditions;

[8] Docket Number: PHMSA-2006-26617, granting a waiver to pipeline safety regulation 49 CFR 195.106 through issue of a Special Permit, April 30, 2007.

- the mill to incorporate a comprehensive inspection program to check for defects and inclusions that could affect the pipe quality;
- a quality assurance program for pipe weld seams to assure they meet the minimum API 5L requirements for tensile strength, maximum hardness for a cross-section of the weld seam in one pipe per heat (maximum hardness must be 280 Vickers), and 100% ultrasonic (UT) inspection of the weld seam after expansion and hydrostatic testing;
- the pipe to be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inch, calculated using the method in Pipeline Research Council International's (PRCI), *Reliability Based Prevention of Mechanical Damage to Pipelines*; and
- the pipe to be subjected to a minimum mill hydrostatic test pressure of 95% of SMYS for 10 seconds.

Additional requirements were also specified by TransCanada in pipe specification TES-PIP-SAW-US[9]. This document states that all pipe shall meet at a minimum, the requirements of API 5L, 43rd Edition and shall be satisfactory for installation, testing, and operation by Keystone in accordance with the latest edition of ASME B31.8, *Gas Transmission and Distribution Piping Systems*[10]. The requirements for carbon equivalent (Pcm) specified by TransCanada were actually more stringent than the Special Permit requirements at 0.200% for Grade X70 pipe. This specification also states that any OD or inner diameter (ID) imperfection having depth resulting in a remaining wall thickness less than 95% of the nominal wall thickness shall be considered a defect. Surface scores (e.g. sharp notches, gouges, scores, slivers) and all stress raising imperfections shall be removed by grinding even if less than the maximum permissible depth for imperfections. TransCanada employed personnel at the pipe mills and coating plants for quality assurance[11]. Had the mechanical damage that caused the failure been evident at the time the pipe was coated at the mill, it should have been rejected.

As confirmed by the Berg Steel Pipe Corporation mill test report (MTR) for heat number W8E596, the slabs were fully killed, continuously cast and thermo-chemically control rolled. The pipes tested in heat W8E596 met the Special Permit, API 5L 43rd Edition, and TES-PIP-SAW-US requirements for tensile, Charpy impact, chemistry (including carbon equivalents), DWTT, and hardness testing. The MTR also confirmed that the long seams were inspected by UT and hydrostatically tested in accordance with CSA Z245.1-07, API 5L 43rd Edition, TES-PIPE-SAW, and TES-PIPE-SAW-US. The mill hydrostatic test pressure did deviate from the Special Permit and TES-PIPE-SAW-US requirement. Instead of testing to a minimum mill hydrostatic test pressure of 95% of SMYS ([redacted] psig) for 10 seconds, the pipe joints were tested to only

[9] TES-PIPE-SAW-US Specification for SAW Pipe, Revision 0, December 7, 2006.
[10] ASME B31.8, Gas Transmission and Distribution Piping systems, latest edition.
[11] PHMSA Audit #19 of Spread 4B week of August 24, 2009.

90% of SMYS ([redacted] psig) for 10 seconds[12]. Subsequently, the pipe was tested to 100% SMYS during the commissioning hydrostatic test which was also required by the Special Permit.

The metallurgical analysis conducted by the NTSB[13] confirmed that for pipe joint 857504 the yield strength and elongation exceeded the minimum requirement for API 5L, Grade X70, PSL2 steel and that the tensile strength was below the maximum tensile strength permitted per the specification. In addition, the impact energy at all test temperatures exceeded the minimum API 5L requirements and those of ASME B31.8. The composition analysis was also within allowable ranges per API 5L.

The pipe in heat W8E596 met all the requirements in the pipe specifications and Special Permit, aside from the mill hydrostatic test pressure[12], and would not be expected to be more susceptible to mechanical damage than other pipe used to construct Keystone Phase 1. In addition, TransCanada inspectors were at the pipe mills and coating plants to verify product quality prior to shipment to the construction site.

3.6.1.2 Damage Occurred During Pipe Shipping, Receiving, or Storage (Eliminated)

Damage to pipe joint 857504 could have occurred after the pipe left the mill but before it was received at the construction site or during storage before it was hauled to the site for stringing.

According to Exhibit F of the service contract[14], the contractor selected for handling and storage of line pipe was responsible for working with TransCanada to witness the receipt of the line pipe while TransCanada was responsible for inspecting all activities related to handling, storage, or hauling of pipe. Upon receipt of pipe, the contractor was to visually inspect the entire pipe and condition of the factory-applied FBE coating. Prior to acceptance, both the contractor and TransCanada were to come to agreement as to the amount of damaged coating to be repaired per the coating specification TES-PIPE-FBE[15]. Although the contract stated that the contractor was responsible for coating repairs, this activity was actually performed by a separate entity according to witness statements.

The authorized inspector was required to make a written record which set forth the quantity and condition of the received line pipe. The written record was documented on the Daily Pipe

[12] A correspondence between TransCanada and PHMSA dated July 17, 2012 demonstrated that in consideration of the end load compensation per API 5L and reporting of gauge pressure as per API 5L, the pipe was tested in accordance with Condition 9 of the Special Permit.
[13] NTSB Report No. 18-017, Draft Materials Laboratory Factual Report, February 13, 2018.
[14] Keystone Oil Pipeline Project, Pipe Offload/Transport/Pipe Storage Yard Development, Contract [redacted].
[15] TES-COAT-FBE External Fusion Bond Epoxy for Steel Pipe, Rev 2, May 31, 2007. This procedure describes the technical requirements for qualification, application, inspection, repair, and testing of plant applied fusion bond epoxy coatings intended for gas and liquids pipeline systems.

Receiving Inspection Report[16] for acceptance. Any suspected damage or incorrect pipe materials were described by rail car number and pipe joint number, photographs of the suspected damage were taken, and the pipe joint was set aside for the pipe mill to address by repairing, cutting, or replacing. The line pipe in heat number W8E596 was delivered to the Englevale, ND rail yard between July 30, 2008 and August 1, 2008. There were no reports of suspected damage or incorrect line pipe materials for any of the railcars that delivered the line pipe in heat number W8E596.

After acceptance of the line pipe, the contractor was solely responsible for maintaining its condition. During handling, the contractor used vacuum lifts for offloading pipe to minimize dents, nicks, gouges, and other damage to the pipe, end bevels, and coating. According to the contract, metallic uprights on trucks and trailers were to be completely padded with a minimum PVC thickness of 1/8 inch and non-metallic hold-down straps were to be used during transport to the construction site. The use of chains or cables was prohibited. Out of the entire Keystone Phase 1 project, the contractor only recalled damaging one joint of pipe in their care which was removed and destroyed.

For these reasons, pipe handling during receipt and storage was eliminated as a cause of the damage to pipe joint 857504.

3.6.1.3 Damage Occurred During Pipe Installation (Causal Factor)

Several circumstances or situations could have been present during pipe installation that could have caused the type of mechanical damage found at Ludden +17. Construction sites are crowded with equipment such as side booms and backhoes that if they contacted the pipe could cause the type of mechanical damage that was found at Ludden +17. There are several stages to construction, each of which presents an opportunity for damaging the pipe including:

- Stringing and welding (Eliminated);
- Trenching, lowering-in, and installation of buoyancy control measures (Inconclusive);
- Backfilling and rough cleanup (Inconclusive); and
- Site restoration (Eliminated).

Each stage of construction is discussed in greater detail below along with the rationale on why it was eliminated or determined to be causal to this incident.

[16] Attachment 1, Daily Pipe Receiving Inspection Report, Acceptance and Attachment 2, Daily Pipe Receiving Inspection Report, Suspected Damage.

3.6.1.3.1 Pipe Damaged during Stringing and Welding (Eliminated)

Specialized trailers were used to move the pipe from the stockpiles in the staging areas to the right-of-way (ROW) where the stringing crew distributed the pipe joints according to the design plan as defined on the issued-for-construction alignment sheets. Set-on weights used for buoyancy control were also distributed along the ROW in locations where they were required.

Once the pipes were laid near the trench, cold bends were made to allow the pipeline to follow the planned route and terrain. The pipe sections were then welded together, inspected, grit blasted to clean the surface of the girth weld, and coated with a two-part epoxy to prevent corrosion.

During these activities precautions were taken to prevent damage to the pipe and coating. The Pipeline Construction Specification[17] (Exhibit F) specified that during hauling and stringing no contact between adjacent pipes or between the pipe and truck was permitted. The contractor was required to use non-metallic tie-down straps to prevent damage to the pipe and coating. The use of tie-down chains or cables was not permitted. In the event of extreme wet weather or unstable ground conditions, stringing pipe, weights, and other heavy materials may have been suspended to prevent irreparable damage to the ROW or access roads. In some adverse weather conditions, the Company Representative (CR) may have approved the use of low ground pressure vehicles for stringing or hauling operations.

In addition, when trucking pre-coated pipe, Exhibit F specified that the truck was to be covered with clean tarps that were free of gravel. The truck and trailer were also required to be equipped with mudguards to prevent stones from impacting the load. For pipe not already separated by ropes, the contractor was required to separate each pipe with rubber or other suitable material. Pipe transport was to be performed using the "pyramid" or "nesting" method of stacking.

For construction of Keystone Phase 1, there were pipe setup, bending, end facing, and line up inspectors that completed daily inspection forms detailing the activities that occurred for specific pipeline stationing along the construction spread. Specific checklist items included noting if any damaged pipe or material were discovered. On the day that the pipe 857504 was strung (September 30, 2008), the inspector did not note any pipe damage on the daily report[18]. If damaged pipe was found by the stringing inspector, it should have been recorded on the Damaged Pipe Report[19] and set aside for repair or returned. Moreover, the Pipe Coating and

[17] Exhibit F, Pipeline Construction Specifications, Keystone Oil Pipeline Project, Rev 9, May 1, 2009 and Rev 11, July 1, 2009.
[18] Form C10, Pipe Setup, Bending, End Facing, & Line Up Inspector's Daily Report, Stationing 12300+00 to 12390+00, September 30, 2008.
[19] Form B7, Damaged Pipe Report. This report contains fields for joint number, heat number, length, OD, WT, coating type, flat ends, bevel ding, dents, scars, location of defect, and cause of damage.

Jeeping Inspector's Daily Report[20] (October 21, 2008) did not report any coating damage on pipe joint 857504 containing the mechanical damage. However, because the mechanical damage occurred near a mill weld, the mill weld may not have been inspected for coating holidays at this time since it did not receive a field-applied two-part epoxy coating as would an automatic weld made in the field.

Because damage was not documented on the pipe setup, bending, end facing, line up, and pipe coating inspection reports and the investigation team has knowledge that the pipe was jeeped prior to lowering-in without any indication of coating damage (see Section 3.6.2.3.2.1), mechanical damage occurring during stringing and welding was eliminated as a casual factor.

3.6.1.3.2 Pipe Damaged during Trenching, Lowering-In, and Set-on Weight Installation (Inconclusive)

After the pipe had been welded along the ROW, the trench was excavated to a depth that would accommodate the pipeline and maintain a depth of cover (DOC) of at least four feet above the top of pipe. As prescribed in Exhibit F, when saddle type set-on weights were required for buoyancy control, the DOC had to be at least four feet above the top of the set-on weight[21]. This necessitated a greater minimum trench depth than would be the case where set-on weights were not installed.

Equipment that was used on Spread 2A during trenching, lowering-in and set-on weight installation included backhoes for trenching (see Figure 11), tracked side-booms with slings to lower-in the pipe (see Figure 12), and backhoes for weight installation (see Figure 13).

The investigation team reviewed inspection documentation, interviewed witnesses that were involved with construction of Spread 2A, and evaluated the NTSB metallurgical analysis to determine if the mechanical damage could have been caused by the concrete weights or construction equipment working along the ROW.

[20] Form C11, Pipe Coating/Jeeping Inspector's Daily Report, Stationing 12300+40 to 12353+76, October 21, 2008.
[21] Section 16.3 of Exhibit F, Pipeline Construction Specifications, Rev 9, May 1, 2009.

Figure 11. Backhoes Working on Spread 2A between 115th and 116th Streets on November 7, 2008

Figure 12. Sidebooms Lowering-In Pipe along Spread 2A between 115th and 116th Streets on November 5, 2008

Figure 13. Example of Equipment used to Lower Set-on Weights onto Pipe

3.6.1.3.2.1 Set-on Concrete Weights Damaged Pipe (Eliminated)

According to witness statements, the design team collected soils data at the pump stations and river crossings but not along the length of the pipeline unless dictated by specific engineering requirements (e.g. geological conditions causing additional stress). Instead, the design team made use of publically available soils data from agencies like the United States Geological Survey (USGS) as input into the pipeline design. Based on the input data used, the failure location was not originally identified as a location needing buoyancy control per the drawings issued for construction.[22] However, because of the difficulties caused by the combination of weather and ground water levels during construction, it was decided in the field that buoyancy control was necessary between 115th Street and 116th Street. A total of 261 set-on concrete weights were added. Specifically, 15 set-on concrete weights[23] were added between Station [redacted] and Station [redacted] which encompassed pipe joint 857504. Due to the highly dynamic nature of pipeline construction projects, it would not be unusual for changes like this to be made in the field.

[22] Keystone Pipeline Mainline – Alignment Sheet, Issued for Construction, Rev 1, May 12, 2008, Spread 2A, Stationing 12303+51 to 12383+51, Drawing No. 1832-03-ML-02-012.
[23] As-Built Alignment Sheet, MP 234.17 to MP 236.64, Rev 2, October 12, 2008, Drawing No 1832-03-ML-02-008.

Each set-on, concrete weight was a nominal 9,000 pounds and contained steel reinforcing bars with lifting hooks. The weights were formed in the field around a felt-like 40-oz protective padding and were designed to have a minimum of three inches of concrete covering the rebar to prevent damage to the pipe when the weight was installed (see Figure 14 and Figure 15). Each weight extended 14 inches above the top of pipe, 15 inches laterally on each side, and was 5 feet long.

As described in the Pipeline Construction Specifications (Exhibit F), the set-on concrete weights were to be installed by lifting both eye hooks simultaneously (as shown in Figure 13) to minimize stress in the concrete when transporting or setting the weights. The face-to-face spacing of the weights in the failure location was approximately 12 to 13 feet with the nearest weight being approximately three feet away from the rupture initiation point. Exhibit F did not specify the exact method for placing the weights on the pipe but anecdotally industry practice was to pick up and set down the weight vertically without sliding it along the pipe. In addition, those involved with the construction of Spread 2A and the daily construction logs confirmed that if the trench had filled with water during weight installation, the water would have been pumped out prior to conducting any work on the pipe to ensure that it was visible to minimize potential damage and to allow for visual detection if damage did occur.

The metallurgical analysis performed by the NTSB examined the minerology of the aggregate comprising the concrete weights which might be hard enough to damage the Grade X70 pipe. They identified quartzite and feldspar with Mohs hardness of 7 and 6, respectively, as the most likely materials to produce gouges in steel (see Figure 16). If these minerals caused the damage found on pipe joint 857504, they would tend to break up in the process leaving pieces of quartzite and feldspar in the sliding contact marks. The NTSB did not find any evidence of these minerals embedded in the sliding contact marks. As discussed in Section 3.6.1.3.2.2, the NTSB found evidence of transferred metal consistent with hardened steels used in construction equipment. Because of the protective padding on the concrete weights, the low probability that the concrete weights were slid horizontally along the pipe, and the lack of concrete residue in the sliding contact marks, accidental contact between the concrete weights and the pipe surface was eliminated as a potential cause for the damage to pipe 857504.

[redacted]

Figure 14. Schematic of Set-On, Concrete Weights used for Buoyancy Control

Figure 15. Cut Section of Set-On Concrete Weight Showing Protek 40 Protective Padding (left hand side of photo)

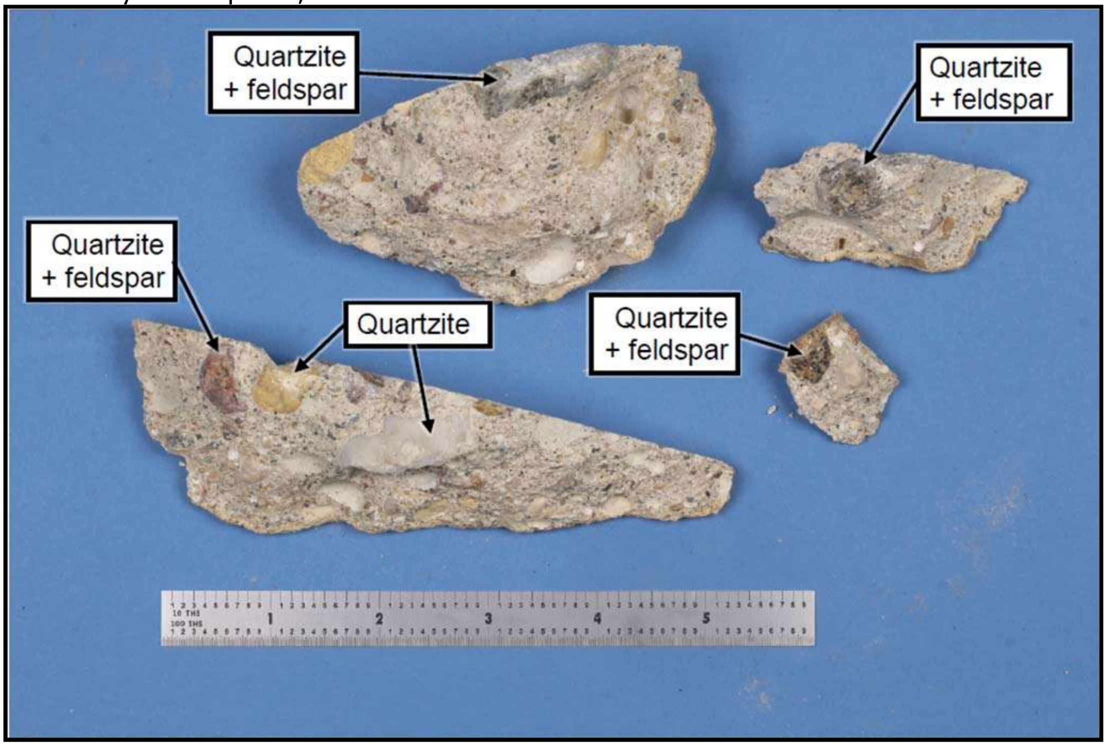

Figure 16. Concrete Aggregate Material Used to Manufacture Set-On, Concrete Weights Highlighting Locations with Quartzite and Feldspar

3.6.1.3.2.2 Equipment Working Along the ROW Damaged Pipe (Causal Factor)

Per Exhibit G of the construction contract[24], the objective of trenching was to provide a ditch of sufficient depth and width with a bottom to continuously support the pipeline. If concrete weights were to be used for negative buoyancy of the pipeline, the minimum DOC was required to be measured from the top of the concrete weight to the original ground contour. During trenching operations, the construction contractor was required to:

- Segregate subsoil materials from topsoil in separate, distinct rows to limit any admixing of topsoil and subsoil during handling of these materials;
- Leave gaps in the spoil piles that coincided with breaks in the strung pipe to facilitate natural drainage patterns and to allow the passage of livestock or wildlife;
- Conduct lower-in and backfill operations as close as practicable to trenching operation to minimize the length of time the ditch is open; and
- Keep the trench free of construction debris (e.g. welding debris) and other garbage.

[24] Section 16, Keystone Pipeline Project, Construction Mitigation and Reclamation Plan, Exhibit G, Rev 3, April 4, 2006.

Trenching in the area between 115th Street and 116th Street occurred on the same day that the pipe was lowered-in, November 7, 2008. The Trenching Inspector's Daily Report[25] indicated that there were abnormal conditions that adversely affected construction progress and sloughing of the trench in water sands. This inspection report also stated that extra depth was required for the installation of the set-on concrete weights used for buoyancy control. The need for buoyancy control and its associated depth of cover should have been documented in a technical variance report but no such documentation was provided to the investigation team. The conditions along the ROW on the day pipe joint 857504 was lowered-in are shown in Figure 17.

Construction of Spread 2A in northern South Dakota was hampered by continued rain events in the fall of 2008 resulting in abnormally saturated soils and difficult environmental conditions for construction. As shown in Figure 18, a near record daily rainfall amount of 0.59 inch occurred on November 6, 2008 (the day before the pipe was lowered-in at Ludden +17) at the Sisseton, SD weather station which is located nearby the failure site. It was also raining on November 7, 2008, the day the pipe was lowered-in.

Figure 17. ROW Conditions along Spread 2A on November 7, 2008

[25] Form C7, Trenching Inspector's Daily Report, November 7, 2008, Stationing 12326+00 to 12338+00.

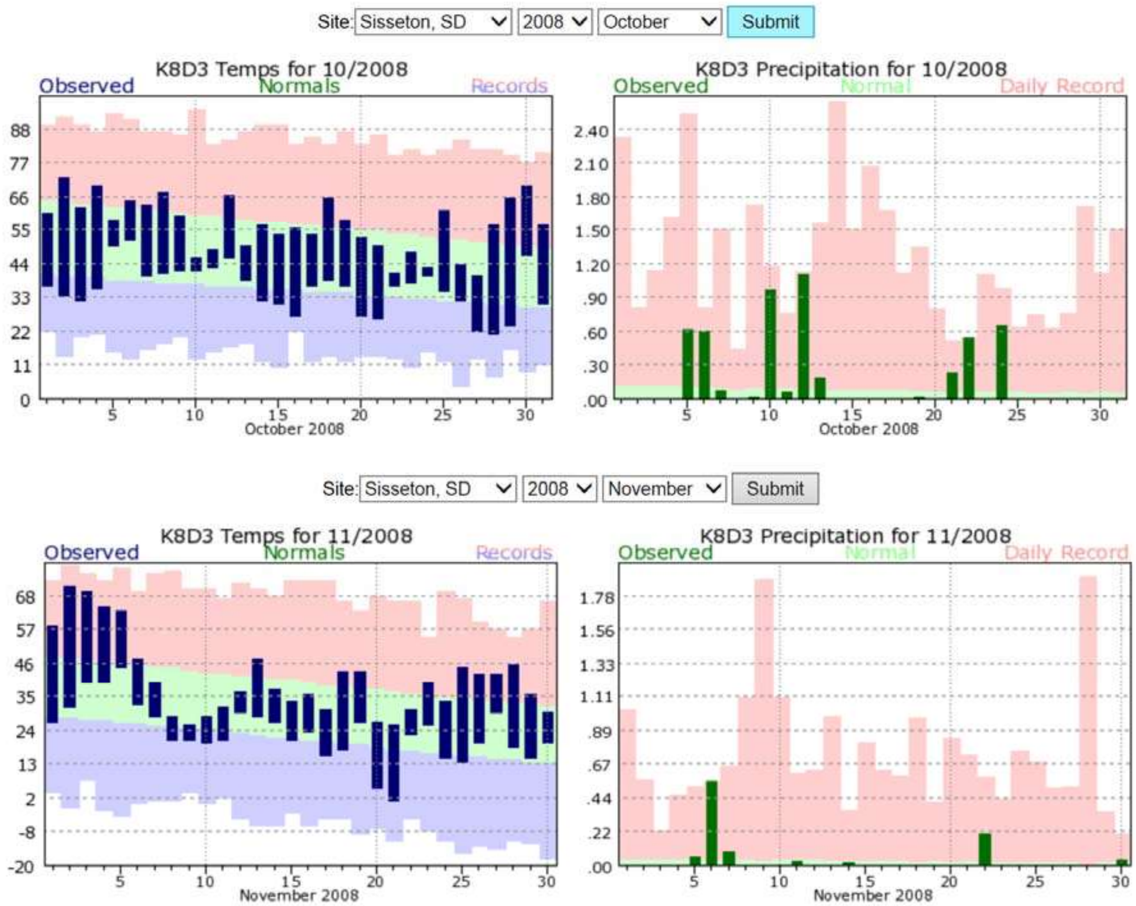

Figure 18. Monthly Precipitation and Temperature Data for the Sisseton, SD Weather Station in October and November 2008[26]

During the metallurgical analysis[27], the NTSB found evidence of metal transferred to the pipe with a higher chromium content consistent with hardened steels used in various components of construction equipment. As shown in Figure 19, the circled areas on the surface appeared lighter gray and more reflective. These areas were all located within the sliding contact marks. Energy dispersive x-ray spectroscopy (EDS) spectra in these areas showed a higher chromium peak than the undisturbed pipe surfaces (see Figure 20). The EDS spectra consistently identified chromium within the sliding contact marks but did not find evidence of chromium in undamaged pipe between marks. Figure 21 highlights surface deposits with higher chromium content relative to the base metal. These areas appear smoother and slightly lighter gray and were only found within the sliding contact marks. In some areas, multiple higher chromium layers were present. Transfer of metal from the contacting object is commonly observed in mechanical damage on pipelines.

[26] U.S. Climate Data; https://www.usclimatedata.com/climate/sisseton/south-dakota/united-states/ussd0316/2008/11
[27] NTSB Report No. 18-017, Draft Materials Laboratory Factual Report, February 13, 2018.

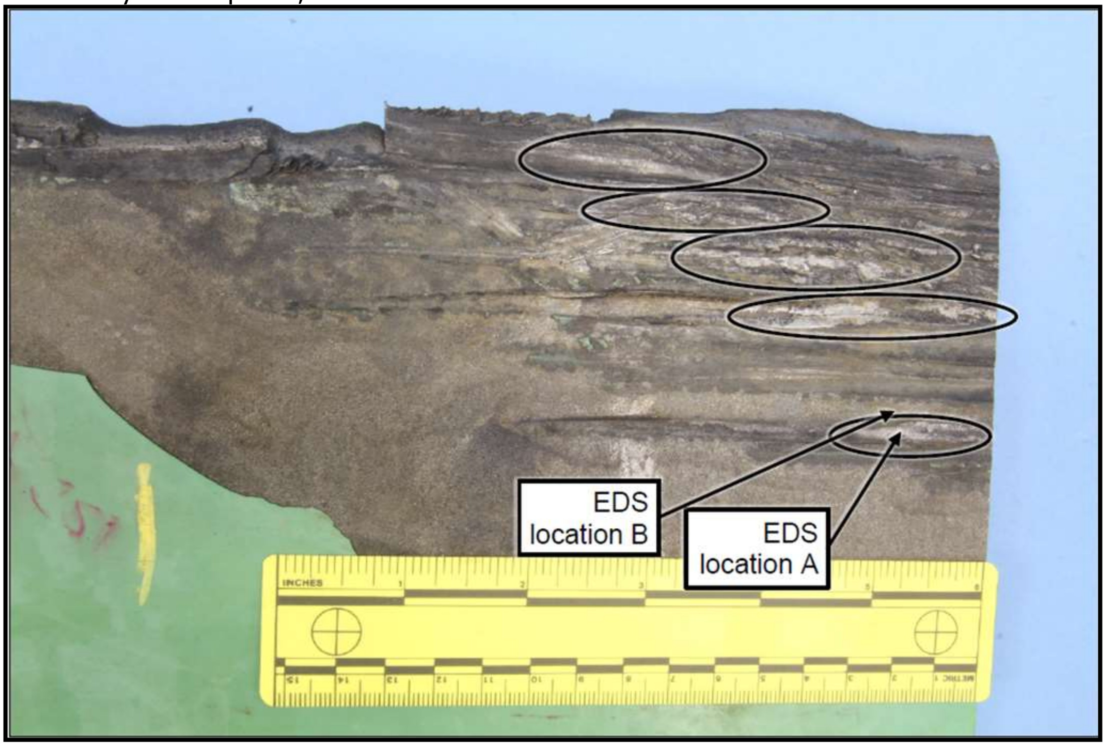

Figure 19. Locations for EDS Analysis (within a sliding contact mark and undisturbed metal)

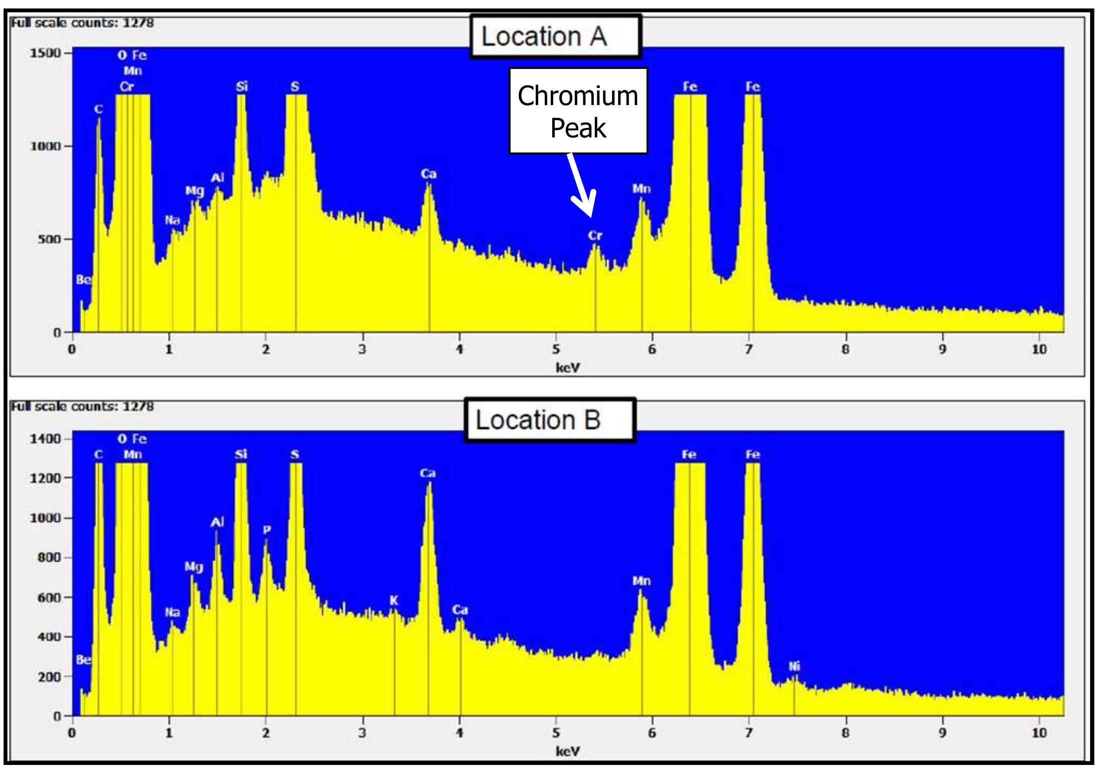

Figure 20. EDS Spectra Indicated in Figure 19. Chromium was consistently present in the sliding contact marks but was mostly absent in undamaged areas.

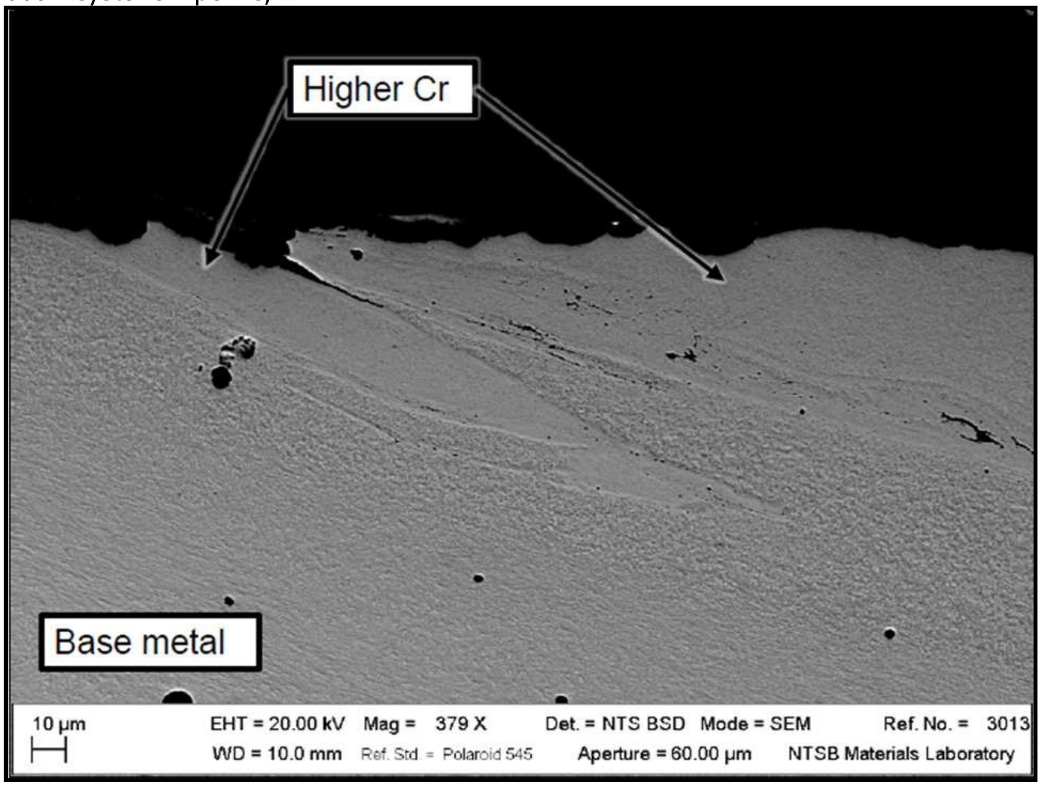

Figure 21. Backscattered Image of Surface Mount Showing Surface Deposits with Higher Chromium Relative to the Base Metal

Backhoe Bucket Damaged Pipe (Eliminated)

Anecdotal information indicated the possibility that the trench may not have been deep enough to accommodate the set-on concrete weights and still attain the four foot DOC from the top of the weight. Some Daily Construction Progress Reports[28] indicated that side-digging may have occurred to achieve the required DOC after the pipe had been lowered into the trench. In this situation it would have been possible for the bucket from a backhoe to contact the pipe. However, the mechanical damage feature that failed consisted of a regular pattern of long scrapes oriented approximately axially and spaced approximately a ¼-inch apart. This damage signature is not consistent with the damage expected from a backhoe bucket operating perpendicular to the pipeline. Impact from the tooth of the bucket would be expected to show more randomly sized and positioned gouging oriented in the circumferential direction. Moreover, several people involved in the construction of Spread 2A indicated that a bar would be welded across the teeth of a backhoe to minimize damage from a tooth if it did contact the pipe (see Figure 22).

[28] Keystone Pipeline Project, Daily Construction Progress Report, US Pipeline Spread 2A, November 7, 2008.

Figure 22. Photo Showing Backhoe Bucket with Welded Bar

Tracks of Equipment Damaged Pipe (Causal Factor)

The mechanical damage found on pipe joint 857504 is more consistent with what would be expected from repeated contact with the pipe. Considering the types of machines in use during construction, contact by tracks or cleats of moving tracked equipment, such as a backhoe or sideboom, is the most likely cause of the damage pattern. As already discussed, the ROW conditions were muddy and soft making construction difficult. Construction was performed from the north to the south, with the working side for the sidebooms being on the west. As shown in Figure 23, backhoes used for trenching were working along the east side of the trench which was the side on which the mechanical damage occurred (between the 11:00 and 12:00 clock positions). The trenching equipment appears to have been in relatively close proximity to the pipeline during lowering-in.

Figure 23. Backhoe Working on the East Side of the Trench on November 3, 2008

PHMSA audits were conducted along Spread 2A at least twice a month since construction began. During an audit[29] conducted on July 8, 2008, there was a finding that the top of a concrete weight was only at a burial depth of 3 feet 8 inches rather than the required four-foot depth. The response from Keystone about the audit finding was "weights were being installed in a depression and we believe the trench was initially deep enough, but because of the significant inflow of water, sand and soil in the conditions encountered one weight measured 3 feet 8 inches cover, or 4 inches less than the desired 48 inches. Due to the ground conditions previously referenced, Keystone's supervisor made the decision to accept the condition and get the remaining weights installed before any further loss of cover was experienced." This audit finding as well as notes on the Trenching Inspector's Daily Report[30] and Daily Construction Progress Report[31] corroborated that construction crews were having difficulty maintaining the appropriate trench depth to maintain four feet of cover over the top of the set-on, concrete weights.

On the day pipe joint 857504 was lowered-in, November 7, 2008, the Trenching Inspector's Daily Report noted sloughing of water sands and that the conditions adversely affected

[29] TransCanada Keystone Pipeline U.S., PHMSA Safety Audit Exit Interview Documentation, Disposition Table.
[30] Form C7, Trenching Inspector's Daily Report, November 7, 2008, Stationing 12326+00 to 12338+00.
[31] Keystone Pipeline Project, Daily Construction Progress Report, US Pipeline Spread 2A, November 7, 2008.

construction progress. Knowing the proximity of the equipment to the trench and the recognition that the conditions along the ROW made it difficult to maintain stability of the trench, it seems plausible that the cleats on the backhoe track could have inadvertently come into contact with the pipeline as the trench sloughed in and possibly concealed the pipe. Under those conditions an equipment operator could inadvertently position the machine in much closer proximity to the pipe than intended. As the backhoe moved away, the cleats could have contacted the pipeline multiple times creating the series of axially-aligned sliding contact marks between the 11:00 and 12:00 clock positions (see Figure 24). If this happened, the backhoe operator may not have been aware that the equipment contacted the pipe and the damage may have been concealed by mud and therefore not be seen by workers along the west side of the ROW.

Although it could not be conclusively determined that cleats from tracked equipment caused the mechanical damage on pipe joint 857504, it is the most plausible conclusion based on the evidence uncovered during this investigation and based on expert opinions.

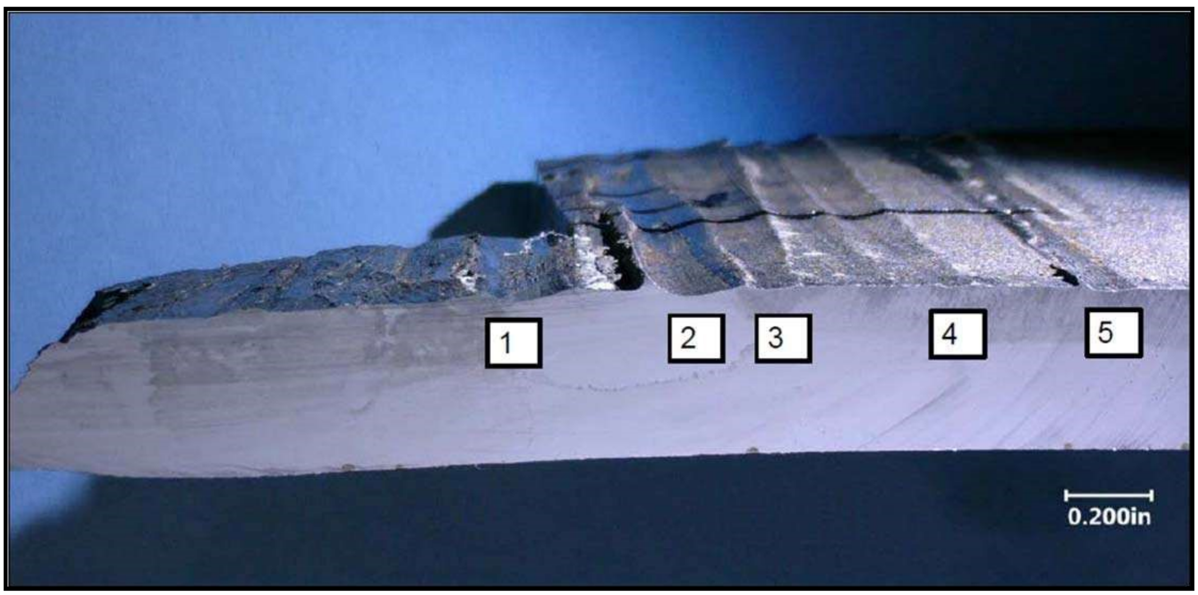

Figure 24. Profile View of the Multiple, Axial Sliding Contact Marks

Causal factors that allowed pipe joint 857504 to be damaged include:

- Adverse work environment (causal factor). The wet, muddy conditions made work along the ROW more difficult. As the trench was dug deeper, it continued to slough and refill with water sands, potentially covering the pipe. The sloughing of the trench could have allowed backhoe equipment digging the trench to get too close to the pipe potentially contacting the pipe with the moving cleats on the track causing the damage that eventually led to the failure. In addition, the sloughing of the trench could have made it difficult for the work crews to visibly monitor the pipe condition from the west side of the ROW as these activities were ongoing.

- Supervision and inspection did not identify the potential hazard (causal factor). The potential hazard of backhoes working close to the pipeline to add extra trench depth in such adverse ROW conditions was not fully recognized. The damage occurred opposite to the working side of the trench which could have hindered visual detection and additional inspections were not implemented to compensate for difficulties encountered under the adverse work conditions.
- Procedures and inspection forms did not fully cover the specific situations experienced during construction of Spread 2A nor was the potential issue identified during pipeline design (causal factor). The need for buoyancy control measures was not identified during the design phase. It was an unusually wet fall in northeast South Dakota which forced the construction crew and TransCanada to make a decision in the field to add set-on concrete weights for buoyancy control. Addition of buoyancy control required additional trench depth to still achieve a four-foot DOC over the top of the concrete weight. To achieve the additional DOC, digging of the trench may have occurred after lowering-in the pipe. The hazards associated with this technical variance should have been evaluated and documented and if necessary additional prevention or mitigation measures put in place. The Pipeline Construction Specifications (Exhibit F) did not provide specific details regarding how the pipeline should be installed when wet, muddy conditions were encountered in the trench requiring the need for buoyancy control and extra DOC. In addition, the Quality Manual[32] did not address the need for additional pipe inspections after adding extra trench depth with the pipe already lowered-in to identify damage.

As such, the root causes that allowed pipe joint 857504 to be damaged are the fact that the standards, policies, and administrative controls (SPAC) did not adequately address the environmental conditions that were experienced during construction of Spread 2A including the need for additional pipe inspections during and after weight installation. Potential improvement opportunities (PIO) were identified for inspection documentation and the use of site specific soils data during the design phase.

[32] Keystone Pipeline, Pipeline Construction Quality Manual, Rev. 0, April 15, 2009.

3.6.1.4 Damage Occurred During Backfill and Rough Cleanup (Inconclusive)

Per Exhibit G of the construction contract[33], the objective of backfilling was to cover the pipe with material that would not be detrimental to the pipeline and pipeline coating. During backfill operations, the construction contractor was required to:

- Eliminate excessive water in the trench prior to backfilling by pumping and discharging into existing drainage to avoid damaging adjacent lands;
- Permanently repair and inspect drain tile;
- Install trench breakers[34] where required on slopes to minimize water movement;
- Place the stockpiled subsoil back into the trench before replacing the topsoil without mixing spoil with topsoil;
- Compact backfill to a minimum of 90% of pre-existing conditions where the trench line crosses tracks of wheel irrigation systems;
- Replace and compact spoil by backhoe bucket or by wheels or tracks of equipment traversing down the trench; and
- Avoid filling trench to the DOC with soil containing rocks of any greater concentration or size than existed prior to construction.

<u>Tracked Equipment Working Along the ROW Damaged Pipe (Causal Factor)</u>

The location of the failure was backfilled on November 8, 2008. Trackhoes and D8R dozers were used on the spread to complete backfilling activities. The Daily Construction Progress Report[35] indicated that conditions were again wet and muddy which affected construction progress. The report also noted that trucks were stuck in the mud requiring the road to be closed.

The ROW conditions were such that it was possible for equipment to sink and get stuck in the mud (see Figure 25). Therefore, it is plausible that as a dozer was working to achieve rough grade during backfill that the blade could have been resting on top of the concrete weight and the back of the dozer sunk down enough to contact the pipe with its track between the weights. Because, the DOC in this location was six feet and the damage occurred in close proximity to a concrete weight, this would have had to occur prior to achieving the full DOC. Additionally, because pipe inspections during backfill activities were performed when the pipe was still visible, damage occurring after the pipe was partially covered would not have been detected. It

[33] Section 16, Keystone Pipeline Project, Construction Mitigation and Reclamation Plan, Exhibit G, Rev 3, April 4, 2006.
[34] Trench breakers are intended to prevent sub-surface transport of water down the (backfilled) trench line.
[35] Keystone Pipeline Project, Daily Construction Progress Report, US Pipeline Spread 2A, November 8, 2008.

is company policy that dozers are not permitted to operate over the pipeline during backfilling, so the postulated damage scenario would be contrary to that policy.

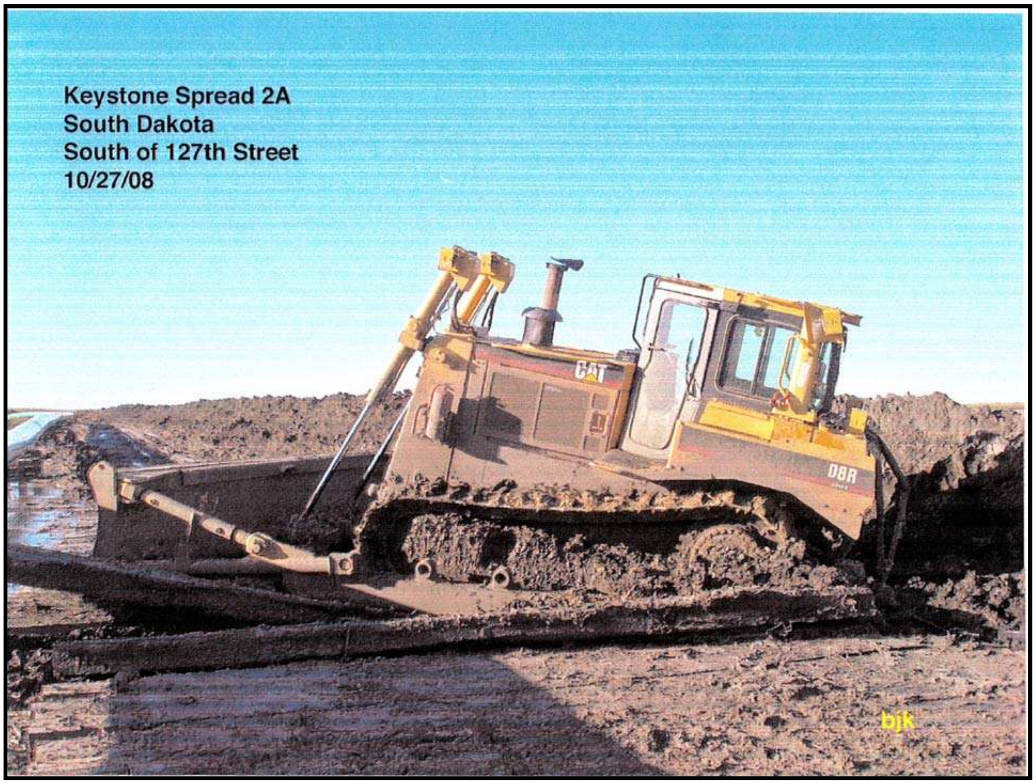

Figure 25. Example of Dozer Stuck in the Mud Along the ROW

The investigation team was not able to conclusively determine if the damage occurred during trenching, lowering-in, and weight installation activities or during backfill activities. Regardless, causal factors were determined associated with equipment working along the ROW damaging the pipe.

- Adverse work environment (causal factor). The wet, muddy conditions during backfill made work along the ROW more difficult with an enhanced potential for equipment to become stuck in the mud.
- Supervision did not identify the potential hazard (causal factor). The potential hazard of equipment used for backfill sinking in to the mud and damaging the pipe was not fully recognized.
- Inspectors did not identify the potential hazard (causal factor). Additional inspections were not implemented to compensate for difficulties encountered under the adverse work conditions.

As such, the root causes that allowed pipe joint 857504 to be damaged are the fact that the SPAC did not adequately address the conditions that were experienced during construction of

Spread 2A including the need for additional pipe inspections to detect mechanical damage after the pipe was covered.

3.6.1.5 Damage Occurred during Cleanup and Final Restoration (Eliminated)

Spread 2A was again hampered by continued rain events in the fall of 2009 resulting in abnormally saturated soils and inadequate conditions for construction cleanup[36]. Final cleanup and restoration activities were performed between September 26, 2009 and October 13, 2009 nearly a year after the pipeline was backfilled near the location of the failure.[37,38] During cleanup, mats used to support heavy equipment on the ROW were removed and the soil was decompacted and graded to prepare it for seeding to return the ROW to its natural state. Equipment used for these activities included dozers and tractors fitted with farm implements such as paraplows (see Figure 26). The Environmental Craft Inspector's Daily Report[39] noted the ROW conditions as very wet at the time of final grading at the failure location.

According to Exhibit G of the construction contract[40], compaction from construction equipment was to be alleviated on all agricultural land. Cropland that had been compacted had to be ripped a minimum of three passes at least 18 inches deep and all pasture and woodland had to be ripped or chiseled a minimum of three passes at least 12 inches deep. Based on interviews, the tractors used to pull the implements used to decompact the soil did not have sufficient horsepower to rip the soil deeper than about two feet. Knowing that the pipeline at the location of the failure was six feet deep and that there were multiple sliding contact marks in close proximity makes it unlikely that pipe joint 857504 was damaged during cleanup and final restoration activities, even though the ROW was very wet at the time. For these reasons, this factor was eliminated as a potential causal factor.

[36] Keystone Oil Pipeline Project Phase 1, South Dakota Public Utilities Commission Quarterly Report, June 30, 2010.
[37] Form C3, Rev 1, Asst. Chief Inspector's Daily Report, Spread 2A, Stationing 12301+20 to 12354+16, September 26, 2009.
[38] Form B4, Unit Price Pay Item/As-Built Report, Spread 2A, Stationing 12327+31 to 12354+16, October 13, 2009.
[39] Form C24, Environmental Craft Inspector's Daily Report, Spread 2A, Stationing 12303+50 to WIP, September 26, 2009.
[40] Section 16, Keystone Pipeline Project, Construction Mitigation and Reclamation Plan, Exhibit G, Rev 3, April 4, 2006.

Figure 26. Example Dozer used for Site Cleanup and Restoration

3.6.1.6 Damage Occurred during Operations (Eliminated)

TransCanada's Operation and Maintenance (O&M) Manual[41] establishes a damage prevention program with requirements to prevent damage to the Keystone pipeline in the vicinity of excavation activities. This program ensures that individuals and contractors that may engage in excavation activities are aware of the location of the pipeline and the necessity of notifying TransCanada when excavation activities may occur near the pipeline. It also ensures that the affected public is aware of the existence and location of the Keystone pipeline and how to notify TransCanada of any activities near the pipeline. The program includes participation in the one-call system, identification of excavators who normally engage in excavation activities in areas near the pipeline, communication to excavators and the general public living or working near the pipeline about the damage prevention program, education programs for excavators, emergency responders, and public officials, a system for receiving and recording notifications to TransCanada of third party excavations, procedures for temporary marking the pipeline before excavation begins, procedures to inspect the pipeline for damage after excavation activities are completed, and monitoring for unauthorized encroachments through aerial patrols.

[41] TransCanada, Operations and Maintenance (O&M) Manual, U.S. Hazardous Liquids Pipelines, Rev 8, February 15, 2015.

Per the Special Permit, the Keystone pipeline must maintain a minimum DOC of four feet, except in consolidated rock. At the location of the failure, the DOC was approximately six feet to the top of pipe because of the installation of set-on concrete weights. In addition, the Keystone pipeline is patrolled at least 26 times per year at intervals not exceeding three weeks. These aerial patrols observe and report activities and conditions near the pipeline ROW that may present a hazard such as ground disturbance, equipment or vehicles near the ROW, new residences or public gathering areas as well as signs of an oil spill. Any activities or conditions of an imminent danger to the pipeline are escalated and reported immediately to the OCC. Line markers are also placed along the pipeline to reduce the possibility of damage. Near the location of the release line markers were placed at nearby road crossings and were visible from the failure location (see Figure 27) as required by Condition 40 of the PHMSA Special Permit.

Figure 27. Line Marker along ROW Near the Failure Location. Photo taken 100 feet away from the marker.

The land use in the area of the failure is part of the conservation reserve program (CRP) in South Dakota. The CRP is a voluntary program available to agricultural producers to help them use environmentally sensitive land for conservation benefits. As such, the land in the area of the failure had been returned to its natural state to improve water quality, control soil erosion, and develop wildlife habitat and therefore was not being used for cultivation activities. In addition there are no road or utility crossings in the area.

Since initial operation of Keystone Phase 1, there have been no one-call events within 1.3 miles (2.1 km) of the failure location (see Figure 28). In addition, the aerial patrol program was not aware of any unauthorized encroachments in the area of the failure dating back to initial operations. A DCVG survey was conducted in October 2010, only four months after the original in-service date of the Phase 1 Keystone pipeline, and had identified a 2% IR indication directly over the location of the failure. Although this indication was not actionable, it can be interpreted as indicating that the damage had occurred prior to the survey. Because the land is not used for cultivation activities, there have been no one-calls or unauthorized encroachments in the immediate vicinity, and there was indication that damage had already occurred by October 2010, damage to the pipeline during operations was eliminated as a potential causal factor.

Figure 28. One-Call Notifications Closest to the Failure Location (represented by purple and blue dots)

3.6.2 Mechanical Damage Not Detected Event Sequence

As discussed in Section 3.6.1, the most likely timeframe in which pipe joint 857504 was damaged was during pipe installation construction activities. Knowing how the damage occurred, the investigation next examined why the mechanical damage was not detected prior to its failure on November 16, 2017.

TransCanada implemented several construction quality safeguards to identify damage to the pipe and coating prior to placing the pipeline into service as defined in the Keystone Pipeline

Construction Quality Manual[42]. The manual outlines the quality management system used during construction of Keystone Phase 1 related to design, receipt of purchased material, and control of construction processes. The Quality Manual specified that all work was to be performed by competent personnel, critical work processes were to be repeatable by following written procedures, critical work processes were to generate written records documenting task completion status, all work output was subject to audit, all nonconformance reports (NCRs) required corrective and preventive actions, and that all records were to be preserved and archived.

Some of the specific quality processes that were implemented include, but are not limited to, visual inspections, regular audits during construction, coating holiday detection, a pre-service hydrostatic test, and a post-construction caliper survey. Moreover, TransCanada conducts regular high-resolution magnetic flux leakage (MFL) ILIs to identify injurious flaws in the pipeline and aboveground electrical surveys to find coating flaws that might be indicative of mechanical damage or other integrity concerns as required by the Special Permit.

According to the NTSB metallurgical analysis, near-surface cracks formed in a sliding contact mark that grew to failure over time due to fatigue crack growth. The safeguards in place to find and repair this type of mechanical damage were not sufficient to detect it during construction, commissioning, and subsequent integrity inspections.

Several possible sequences of causes and effects were postulated to have contributed to the mechanical damage to pipe joint 857504 not being detected during QA/QC and inspections:

- Damage not discovered during mill QA/QC (Eliminated)
- Damage not discovered during shipping, receiving, and storage QA/QC (Eliminated)
- Damage not discovered during pipe installation QA/QC (Causal Factor)
- Damage not discovered during ILI (Causal Factor)
- Damage not discovered during above ground surveys (Confirmed, but not Causal)

Multiple inspections of the damaged pipe joint were conducted at various points during its manufacture, construction, and operation. None of these inspections identified damage in the location of the failure that would warrant action by the mill, construction crews, or integrity management team. As such, the investigation team gathered data to understand why this damage was not detected prior to its failure.

The sequence of events leading to the damage to pipe joint 857504 not being detected is shown in Figure 29 followed by an analysis of potential causal factors and root causes.

[42] Keystone Pipeline, Pipeline Construction Quality Manual, Rev. 0, April 15, 2009.

[redacted]

Figure 29. Damage to Pipe Joint 857504 Not Detected Event Sequence - Cause and Effect Tree

3.6.2.1 Damage Not Discovered During QA/QC at the Pipe Mill (Eliminated)

TransCanada used several specifications to ensure the quality of the line pipe manufactured at the mill, including API 5L 43rd Edition, CSA Z245.1-07, and TES-PIPE-SAW-US. Pipe joint 857504 was manufactured by the Berg Steel Pipe Corporation as part of heat W8E596. The MTR certified that all pipe supplied in this heat were non-destructively examined (NDE) in accordance with and to the acceptance standards previously mentioned and hydrostatically tested to [redacted] psig (90% SMYS). Select pipe samples from each heat were also destructively tested to determine if they met requirements for strength and fracture toughness.

The metallurgical analysis also confirmed that pipe joint 857504 met API 5L specifications for yield strength, tensile strength, toughness, and chemical composition.

Had pipe joint 857504 been damaged at the mill, there were several quality checks in place that should have detected the mechanical damage. It is possible that the damage occurred after the mill visual inspections, NDE, and hydrostatic testing but it would have been subsequently detected during receiving at the construction site. As discussed below, this was not the case and therefore the mechanical damage not being discovered at the mill was eliminated as a potential causal factor.

3.6.2.2 Damage Not Discovered during Shipping, Receiving, and Storage QA/QC (Eliminated)

To ensure that the pipe was shipped free of damage, loaded rail cars were inspected by the mill prior to their release. The railcars were also inspected to make sure they were free of any physical defects and that the pipe had been loaded in accordance with the open top loading rules. Any cars not meeting the requirements would have been reloaded before transporting.

According to the Pipeline Construction Specifications (Exhibit F), TransCanada and the contractor were to both witness delivery of all materials and visually inspect them for quantity and condition with a written record of this inspection. The railcars were inspected as evidenced by the Daily Pipe Receiving Inspection Reports[43] and no pipe damage was noted for any of the railcars that delivered the line pipe associated with heat W8E596.

Pipe joint 857504 would have been handled several more times between receiving and backfill, each time being visually inspected during stringing and welding activities as well as undergoing coating holiday detection (jeeping) just prior to lowering-in. At no point during these activities was pipe or coating damage noted on the daily inspection reports. Moreover, the large patch of missing coating should have been easily detected during jeeping prior to lowering-in so long as

[43] Attachment 1, Daily Pipe Receiving Inspection Report, Acceptance and Attachment 2, Daily Pipe Receiving Inspection Report, Suspected Damage.

qualified operators and functioning equipment were used. Because damage was not noted in any of the inspection documentation, the investigation team believes that the damage occurred after shipping, receiving, and storage and therefore was eliminated as a causal factor.

3.6.2.3 Damage Not Discovered during Pipe Installation QA/QC (Causal Factor)

During pipe installation, the pipe body was inspected visually, with holiday detectors, and with a post-construction caliper survey to identify pipe and coating damage that may have occurred during construction. If damage was found, it was either repaired, cut-out, or the entire pipe joint replaced. Additionally, the pipe was hydrostatically tested to expose any service limiting manufacturing- or construction-related flaws prior to placing the pipe into operation.

3.6.2.3.1 Damage not Detected or Reported during Visual Inspections (Causal Factor)

The investigation team believes that the mechanical damage at Ludden +17 occurred during pipe installation activities. During witness interviews, the investigation team was informed that the only method for detecting damaged pipe once it was lowered-in to the trench was through visual examination from the working side of the ROW (west). For safety reasons, construction crews and inspectors were prohibited from entering the trench after the pipe had been lowered given the lack of slope on the trench wall.

The procedures and associated forms that were used to document visual inspections for pipe or coating damage[44] after lowering-in the pipe, during or after set-on weight installation, or during backfill activities at the time Spread 2A was constructed were lacking specific details on what to visually inspect and record. Other than an area for 'remarks' the forms did not contain details regarding visual observations that should have been made related to pipe or coating damage during these construction activities. A Damaged Pipe Report should have been completed if damage was found but no such document was attached to any of the daily inspection reports. Inspectors did receive training and on-boarding which covered what was expected of them to execute their jobs and maintain construction quality standards even if not specifically addressed on the inspection forms.

Complicating matters were the wet, muddy conditions along the ROW and in the trench. Crews working along the ROW on November 7-8, 2008 when the pipe was lowered-in and backfilled, noted muddy, sticky conditions as well as sloughing of the trench in water sands. As noted in the metallurgical report, the mechanical damage occurred between the 11:00 and 12:00 clock positions which would have been located on the east side of the construction ROW, opposite

[44] ASME B31.4-2006, 436.5.1(b)(1) specifies visual inspection for detection of surface defects in the pipe shall be provided for each job just ahead of any coating operation and during the lowering-in and backfill operation.

the working side. It is possible that the pipe was coated with mud making it difficult to visually detect that damage to the pipe had occurred on the opposite side of the trench. Although construction personnel emphasized that they would not work on the pipe if it were not visible (e.g. covered with water), they may have had difficulty pumping water out of the trench at a sufficient rate keep pace with installation activities and allow for visual inspections. Trenching, lowering-in, weight installation, and backfill crews were all working in sequence to install the pipe which elevated the risk of inadvertent pipe contact and the possibility that the damage would not be detected.

Because of the difficult work environment during pipe lowering-in and backfill as well as inadequate procedures and forms to document visual pipe inspections during these activities, damage not being visually detected during installation was determined to be causal to this incident. Root causes include inspection procedures and processes were not adequately addressed in the SPAC as well as a PIO for inspection instructions and forms.

3.6.2.3.2 Damage not Detected during NDE (Inconclusive)

3.6.2.3.2.1 Damage not Detected during Final Jeeping (Inconclusive)

During pipe installation, the pipe body was inspected with a holiday detector to find areas of coating damage. The pipe used for Keystone Phase 1 was factory coated with FBE and field welds were coated with a two-part epoxy. As discussed in the Pipeline Construction Specifications (Exhibit F), prior to lowering-in of the pipeline, immediately in front of the first lowering in tractor, the contractor was required to inspect the coating for damage using a holiday detector. Any coating defects and damage that was found should have been rectified using acceptable methods in the applicable coating specification (TES-COAT-FBE[45]). Detection of coating damage prior to lowering-in was also required by federal regulation 49 CFR 195.561. This activity was completed by the construction contractor as indicated on the Lower-in Daily Inspector's Report[46].

Per Section 15 of the Pipeline Construction Specification (Exhibit F), the contractor was also required to ensure that a holiday detection survey and coating repairs were completed prior to the installation of set-on concrete weights. Final jeeping of FBE coated pipe with minimum thickness of 14 mils was required to be checked at 1,750 volts DC[47] as the pipe was lifted off the skids during lowering-in. Daily calibration of holiday detectors was required at the start of

[45] TES-COAT-FBE External Fusion Bond Epoxy for Steel Pipe, Rev 2, May 31, 2007. This procedure describes the technical requirements for qualification, application, inspection, repair, and testing of plant applied fusion bond epoxy coatings intended for gas and liquids pipeline systems.
[46] Combined Form C12, C13, Lower-in/Tie-in Inspector's Daily Report, Spread 2A, Stationing 12324+35 to 12337+07, November 7, 2008.
[47] The holiday detection voltage was required to be 125 volts per 25.4 μm (1 mil) of the minimum total coating thickness specified.

the work day and every four hours thereafter. A revision[48] was made to Exhibit F to address issues related to coating flaws remaining undetected by jeeping crews. The revision specified the coating flaw size to be used for calibration and warned that higher voltages may be required depending on the site specific ground conditions at the time of calibration. Although the Lower-in Daily Inspector's Report stated that final jeeping was performed; the documentation related to calibration of the holiday detection equipment, inspection voltages, travel speed during the inspection, and results of the inspection in the area of pipe joint 857504 were never received. Pipe jeeping records both before and after the area containing pipe joint 857504 were provided and did not indicate any major coating issues.

According to the Quality Manual, the lowering-in inspector was to record, at a minimum, contractor progress and activities including holiday detector daily settings and calibration. However, the Lower-In Daily Inspector's Form only contained a 'yes' or 'no' checkbox asking if "Proper holiday detector used/coating repaired first?" The form did not contain any fields to note the holiday detector type, settings, calibration, results, or repairs. Some of this information was included on the Coating Inspection Checklist[49] and Post Coating Inspection[50] forms for field welds but was not provided as part of the Lower-In Inspector's Daily Report. No documentation on calibration of holiday detection equipment in the location of the failure was received.

During construction of Spread 2A, PHMSA recorded several audit findings[51] related to coating crews being unaware of new procedures for jeep voltages, crews not following coating inspection and repair procedures, variations in the application of jeeping procedures, and careless work crews damaging pipe coating. The coating and jeeping related PHMSA audit findings along Spread 2A are summarized in Table 2. There were also three coating related NCRs[52]: (1) fiber board was found adhered to the pipe and then jeeped over during pre-jeeping operations (June 18, 2008); (2) 3M 323 two-part epoxy was not on the approved list but found being used to repair holidays during lowering-in (July 8, 2008); and (3) Royston Handy Cap cadweld coating system was not on the approved list but found being used (July 18, 2008). The non-conformances and PHMSA audit findings were closed prior to jeeping activities at the failure location so it is reasonable to assume these non-conformances were corrected and not repeated at Ludden +17.

[48] The revision was made in response to an audit finding along Spread 4B dated June 16, 2009 was that the FBE coating ring was leaving gouges in the coating that were being undetected by the jeeping crew. The jeep voltage setting was increased from 1,750 volts to 2,100 volts which then detected the coating flaws. The document revision dates were Rev 9 (effective May 1, 2009) and Rev 11 (effective July 1, 2009).
[49] Form C11A, Coating Inspection Checklist, Spread 2A, Stationing 12300+40, October 21, 2008.
[50] Form C11B, Post Coating Inspection, Spread 2A,
[51] PHMSA PL Safety Audit Exit Interview Documentation, Disposition Table, June 23, 2008 to November 17, 2008.
[52] Form B6A, Non-Conformance Report Log, Spread 2A.

Holiday detectors, when calibrated and operated properly, are capable of finding pinholes in the coating. It therefore is reasonable to expect that this inspection would have easily detected the large patch of missing coating on pipe joint 857504. However, because of a lack of documentation, the investigation team could not conclusively rule out that the coating damage was not present during holiday detection.

Table 2. PHMSA Coating and Jeeping Related Audit Findings on Spread 2A[53]

PHMSA Observation	Observation Date	Action by Keystone	Status
Two-part epoxy dispensed without the mixing nozzle and a worker dispensed epoxy directly into a holiday and mixed it at that location with a brush. Mixing of two-part epoxy for holiday repair should be done in the nozzle or on a separate clean material and then applied to the holiday.	June 23, 2008	Spread 2 resident construction supervisor (RCS) was advised of the issue; both Keystone inspectors and the pipeline contractor were counseled (verbally and email) on proper mixing and application.	Closed July 22, 2008
Building insulation was seen still adhering to the pipe on pipe that had been jeeped. The presence of building insulation on the pipe during the jeeping process prevents adequate inspection of the coating.	June 23, 2008	Spread 2 RCS was advised of the issue; both Keystone inspectors and the pipeline contractor were counseled (verbally and email) to ensure pipe is cleaned of foreign materials that could inhibit proper jeeping.	Closed July 22, 2008
A crew unloading cribbing was pushing timbers off of the back of the truck and hitting the coated pipe. This action was relayed directly to the personnel performing this task. Within minutes they were again observed performing the reckless unloading of the timbers as more hit and bounced off the pipe.	July 30, 2008	This observation was passed on to each spread and the RCS's advised inspectors and contractors of the correct way to unload items so as to not damage the pipe coating.	Closed August 15, 2008
A gouge was found that was coated over by mill-applied FBE coating and it was questioned if the WT was adequate.	September 15, 2008	Spread 1 removed the coating, ground the area smooth and found that the remaining WT was adequate.	Closed September 2008
Coating crews were not aware of the new procedures for jeep voltages.	September 18, 2008	Spreads were informed that same week.	Closed October 15, 2008
The jeeping crew's rate of travel while on normal footing was clocked at 14 seconds for 40 feet. Specifications require a maximum travel speed of 2 feet per second. This was discussed and found corrected the following day.	September 18, 2008	Spreads were informed.	Closed October 15, 2008
Two-part epoxy was observed being mixed after being applied to the area of the holiday. This was corrected during the observation and found adequate the following days.	September 18, 2008	Spreads were informed.	Closed October 15, 2008

[53] PHMSA PL Safety Audit Exit Interview Documentation, Disposition Table, June 23, 2008 to November 17, 2008.

PHMSA Observation	Observation Date	Action by Keystone	Status
Twelve random thickness readings were taken of FBE coating and ranged from 17 mils to 20 mils. The current specification of 14 mils for the development of the jeep voltage specification continues to seem inadequate. It may be beneficial to perform a statistical sampling of actual pipe coating thicknesses for developing the engineering standard.	September 18, 2008	Requested white paper from TransCanada.	Closed October 15, 2008
Observed three different jeep grounding methods being used. Steps should be taken to assure the effective voltage across the coating is appropriate based on the grounding method.	September 30, 2008	Spreads were informed.	Closed October 22, 2008

3.6.2.3.2.2 Damage not Detected or Reported during Post-Construction Caliper Survey (Confirmed, but not Causal)

On September 2, 2009 the pipeline between MP 218.5 and MP 259 was inspected with [redacted] 360[54] tool in accordance with KPP-901, Rev 5[55] and the Pipeline Construction Specifications (Exhibit F). Only one deformation was detected during the survey at a depth of 1.91 inches (6.4% of the OD) located near the bottom of the pipe. The dent was near MP 256.9 which is approximately 22 miles downstream of the failure location. The tool's reporting threshold for dents was 2% of the OD with a 90% probability of detection (POD). Tools are capable of detecting a shallower indentation, but potentially with lower POD, larger error in sizing, or both. TransCanada requested TD Williamson to report dents down to 1% of the OD. For this pipeline, the minimum detectable dent with a POD of 90% would measure 0.6 inch (30 inches x 2%) or 0.3 inch (30 inches x 1%) at the 1% reporting threshold.

If the analysis of the caliper tool survey showed indications of pipe defects exceeding allowable limits, the construction contractor was responsible for locating and correcting the defects and rerunning the caliper tool. Indications that required excavation included all sharp defects, all sharp defects on welds, all sharp defects on dents, and dents deeper than 1% of the pipe diameter and longer than 37.5% of the pipe diameter in any direction along the pipe wall.

The dent at MP 256.9 was excavated and removed on October 10, 2009 because it exceeded the allowable defect limits. No other indications of dents, ovalities, expansion, or heavy welds were found in this section of Keystone Phase 1. The investigation team believes that the mechanical damage found at Ludden +17 existed at the time of the caliper survey; however, as confirmed by the metallurgical analysis, there was no denting of the pipe observed that exceeded the caliper tool's reporting threshold. Note, however, that the rupture process

54 [redacted] 360 Survey Report, MP 218.5 to MP 259, September 3, 2009.
55 KPP-901, Rev 5, Specification for Cleaning, Filling, Hydrostatic Testing, Dewatering, Drying and Caliper, July 10, 2009.

distorts the pipe wall contour and may mask the presence of shallow indentation present at the point of rupture.

When construction equipment comes into contact with the pipe, it may or may not cause denting. In some circumstances, construction equipment may only move or remove (gouge) metal on the surface of the pipe when it comes into contact without generating any appreciable denting. A caliper tool can only detect the denting associated with equipment contacting the pipeline, the depth of which depends on the applied forces and the yield strength of the pipe. Pipes with higher yield strengths will contain smaller dents for the same applied force. The pipe's wall thickness is also an important factor as thicker pipe is stiffer and will deform less. The wall thickness for pipe joint 857504 was 0.386 inch with average yield strength of 87.7 ksi, significantly stronger than its X70 grade specification. Therefore, any denting that may have occurred during impact would likely be smaller and more challenging to detect using conventional caliper tools.

Another factor that would make detection of damage from construction equipment more challenging is the direction of the applied force on the pipe. Forces perpendicular to the pipe are more likely to cause denting while forces applied at oblique angles (e.g. surface shearing forces) can create gouges or scrapes. A caliper tool may not be as successful detecting gouging and denting at oblique angles because the deformations will be smaller and likely below reporting thresholds. The anomaly that failed was a narrow, axial sliding contact mark with no apparent denting. For this reason, the caliper tool not detecting the mechanical damage was eliminated as a causal factor for this incident because there was no appreciable denting to detect.

3.6.2.3.3 Damage not Detected during Commissioning Hydrostatic Test (Confirmed, but not Causal)

TransCanada conducted a hydrostatic test for Keystone Pipeline Section 2A-4 on June 26, 2009 for a 40.38-mile long section between MP 218.82 and MP 259.18. The maximum actual test pressures achieved during the hydrostatic test are shown in Table 3. These pressures met the conditions of the Special Permit which required a commissioning hydrostatic test to at least 100% SMYS and 1.25 times the design MOP as well as the requirements contained within the Keystone hydrostatic testing procedure KPP-901[56]. The minimum required test pressure to meet these requirements was [redacted] psig. TransCanada submitted all hydrostatic test reports[57] for the Keystone Phase 1 pipeline to PHMSA after completion per the conditions in the Special Permit.

[56] KPP-901, Rev 5, Specification for Cleaning, Filling, Hydrostatic Testing, Dewatering, Drying and Caliper, July 10, 2009.
[57] Hydrotest Summary Report, Keystone Pipeline – 2A-4 Section, MP 218.82 to MP 259.18, June 26, 2009.

Table 3. Maximum Actual Hydrostatic Test Pressures for Spread 2A-4 Between MP 218.82 and MP 259.18

[redacted]

The construction contractor began filling the line with water on June 22, 2009 at 10:30 AM and completed filling the line at 1:00 AM on June 24, 2009. Pressurization of the line began two days later on June 26, 2009 at 8:20 AM. The eight-hour minimum test period began at 6:00 PM at a test point pressure of [redacted] psig. The strength test ended at 10:00 PM and the leak test portion was started at the same time. According to Keystone procedure KPP-901 a minimum period of two hours near the end of the eight-hour test period was required, during which the pressure did not fall or the duration of the test was to be increased until such a period had occurred. The pressure did not stabilize until 9:30 AM on June 27, 2009 where it held steady at [redacted] psig for two hours before the test was successfully ended. The pressure and temperature profiles recorded during the hydrostatic test are shown in Figure 30.

[redacted]

Figure 30. Hydrostatic Test Pressure and Temperature Trend for Spread 2A-4 Between MP 218.82 and MP 259.18

The investigation team believes that the damage to pipe joint 857504 occurred sometime during lowering-in and weight installation. If so, the damage would have existed at the time the hydrostatic test was conducted. Based on the metallurgical examination the deepest portion of the sliding contact marks was approximately 0.046 inch deep. Damage to the microstructure of the metal under mechanical damage can vary but is usually less than 10% of the pipe wall thickness. Initial cracking during either formation of the mechanical damage or re-rounding during pressurization usually occurs within this layer. An assumed crack as long as the observed region of sliding contact marks, 30 inches, and having an aggregate damage depth (scrape plus crushed microstructure) of 0.085 inch, and considering actual strength and toughness of the pipe, would have been expected to survive a hydrostatic test to 100% SMYS. Using the Modified Ln-Sec equation, the calculated failure pressure would have been 1,895 psig. Some test pressures in Spread 2A-4 between MP 218.82 and MP 259.18 exceeded this pressure at low elevation points, but shorter actual crack features would have withstood even those test pressures. Based on this analysis, the commissioning hydrostatic test would not have detected the mechanical damage on pipe joint 857504 and is therefore not causal to this incident.

3.6.2.4 Damage Not Discovered During In-Line Inspection (Causal Factor)

As part of TransCanada's integrity management program (IMP) regular ILIs are conducted to identify injurious flaws in the pipeline. If flaws are detected, TransCanada applies criteria to determine flaws that require a response. Spread 2A is comprised of two piggable segments, the last 41 miles of KS5 from Elm Creek to Fort Ransom and the first 88 miles of KS6 from Fort Ransom to Freeman. The failure occurred in piggable section KS6.

The ILI technologies chosen for the integrity assessments were axially-oriented magnetic flux leakage (MFL) technology which primarily detects metal loss anomalies and caliper technology which detects dents. MFL combined with geometry tools are the most commonly used inspection technologies for the detection of metal loss and dents. Most pipeline companies choose an MFL and caliper tool for the first scheduled integrity assessment since corrosion and third party damage tend to be the highest risk threats for a pipeline and these tools can reliably withstand harsh operating conditions.

Per the Special Permit, TransCanada was required to perform a baseline ILI using a high-resolution MFL tool capable of gouge detection within three years of placing the pipeline segment into service. This initial inspection was conducted September 2, 2012 with the [redacted] using triaxial Hall effect sensors and caliper technology. A second inspection was conducted in May 2016 with the [redacted] using triaxial Hall effect sensors and caliper technology. Neither of these technologies detected external metal loss in excess of 10% WT or with a failure pressure ratio (FPR)[58] less than 1.42 within 500 feet of the failure location. As shown in Figure 31, a 2% IR indication from the DCVG survey aligned with a 7% external metal loss feature from the [redacted]; however, the metal loss feature was at approximately the 4:30 clock position whereas the

[58] The failure pressure ratio (FPR) is the ratio of the estimated rupture pressure to the MOP expected during service, i.e. the ratio of the calculated failure pressure of an anomaly to the MOP at the location of the anomaly.

mechanical damage feature that failed was at approximately the 11:30 clock position.[59] In addition, no geometry features were identified near the failure location by either caliper tool.

[redacted]

Figure 31. DCVG and Metal Loss Indications in Proximity to the Failure Feature

The TransCanada reporting threshold for the caliper tool was 1% of the OD, hence 0.3 inches, while the industry standard is typically 2% (0.6 inches) of the OD. Kiefner reviewed the MFL and caliper data at high sensitivity to see if any low level metal loss or denting below the reporting threshold was detectable. Figure 32 shows an image of the MFL and caliper data at high sensitivity with the region of the mechanical damage illustrated. The MFL image shows that no metal loss signal was detectable even at high sensitivity; note an unrelated 7% metal loss signal was clearly seen at this sensitivity level. The high sensitivity caliper image shows a slight deformation with a depth between 0.2% and 0.4% of the OD in the mechanical damage region. The shape of the deformation in the image corresponds well to the observed sliding contact marks as it starts at the 11:00 position at the girth weld and tracks to the top of the pipe further downstream; the length and width also correspond well. This dent is on the order of the natural variation of the pipe curvature as another 0.2% variation unrelated to mechanical damage can be seen upstream of the girth weld at the 3:00 position. Therefore, it is unlikely that caliper data analysis would have reported this slight dent.

[59] Integrity Review of the Keystone Ludden +17 Accident, Rev 3.0, November 26, 2017.

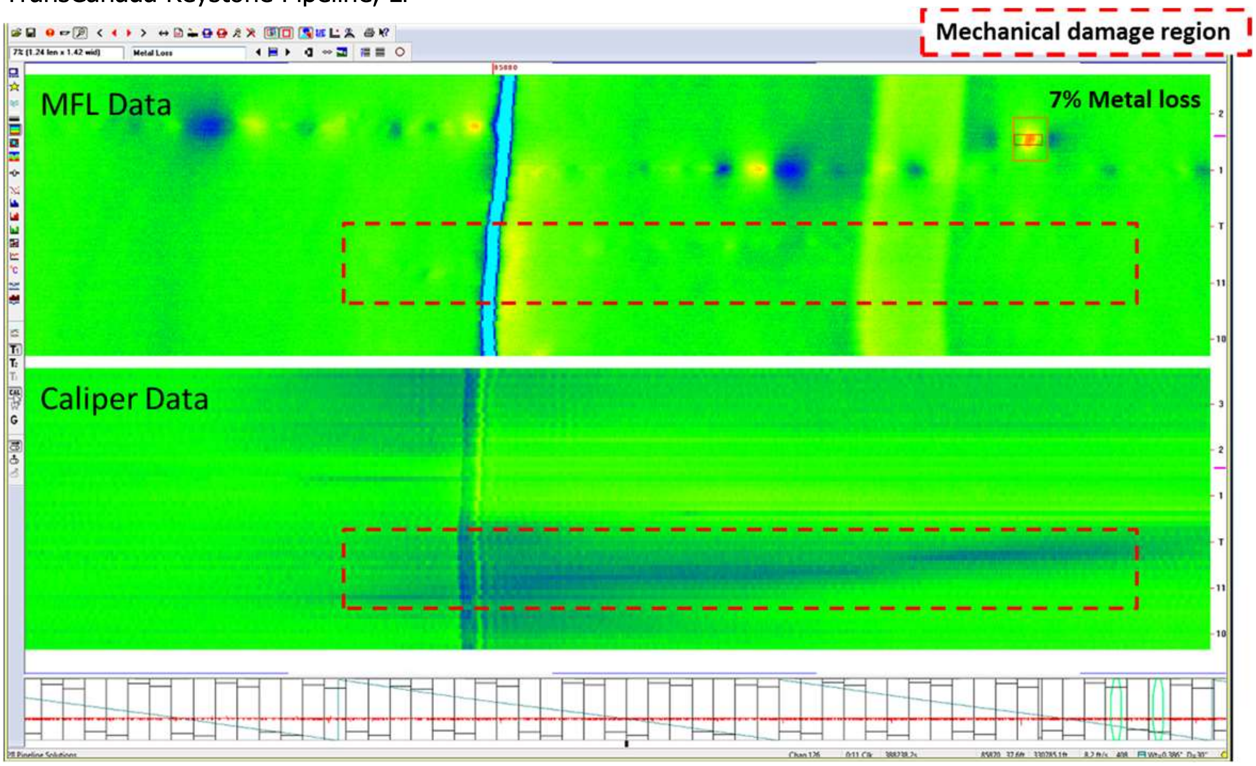

Figure 32. MFL and Caliper Data at High Sensitivity

There were several possible explanations considered regarding why the mechanical damage was not detected by ILI:

- The damage did not exist at the time the ILI was run (Eliminated);
- The tool selected was not capable of detecting this type of damage (Causal Factor); or
- The damage was detected by the tool but its size was below reporting thresholds or not identifiable by the analyst (Confirmed, but not Causal).

As discussed, the investigation team believes the mechanical damage at Ludden +17 was present during all internal inspections yet the inspections never reported metal loss or denting at the failure location. The ILI technologies selected by TransCanada each have capabilities and limitations for detecting, identifying, and sizing the specific anomaly types of concern.

The ability of an axially-oriented MFL tool[60] to detect mechanical damage depends on the orientation and dimensions of the damage. As discussed previously, the mechanical damage feature on pipe joint 857504 did not produce denting in the pipe of sufficient magnitude to be reported by a caliper survey. Therefore, this damage could only have been detected by a technology that produces signals indicating metal loss in the damaged area. As described in

[60] Axial MFL tools magnetize the pipe in the axial direction. Other tools exist where the magnetization is in the circumferential direction and are typically used for detection of long, axial defects like selective seam weld corrosion.

the metallurgical analysis, the mechanical damage feature consisted of multiple, linear sliding contact marks in the axial direction with maximum depth of 12% WT and varied individual lengths up to 13 inches, and varied individual widths up to 0.20 inch. (These dimensions are approximate and may not be fully inclusive of all individual contact marks on the pipe surface.) Metal loss that is long in the axial direction (length) and narrow in the circumferential (width) direction is challenging for axially-oriented MFL tools to detect. Axially-oriented MFL tools do not have the ability to detect an axial crack, which by definition is a long, narrow anomaly. To quantify the applicability of MFL tools for various geometry types, the Pipeline Operators Forum (POF), a group of European pipeline operators, has developed a classification method for metal loss anomalies as illustrated in Figure 33. The definitions of length and width are based on the greater of the wall thickness or 0.4 inch (10 mm) which for the Keystone Pipeline is nominally the same. The darker blue regions illustrate where MFL is most accurate whereas the lighter blue regions illustrate where MFL is more challenged. As indicated by Figure 33, MFL tools have more difficulty detecting anomalies that are less than one wall thickness in width, referred to as axial slotting. Axially-oriented MFL tools also have difficulty detecting anomalies when the length to width aspect ratio is larger than 3 to 1. The dimensions of the anomaly that failed falls into the light blue areas of Figure 33 indicating that detection by axially-oriented MFL would have been challenging.

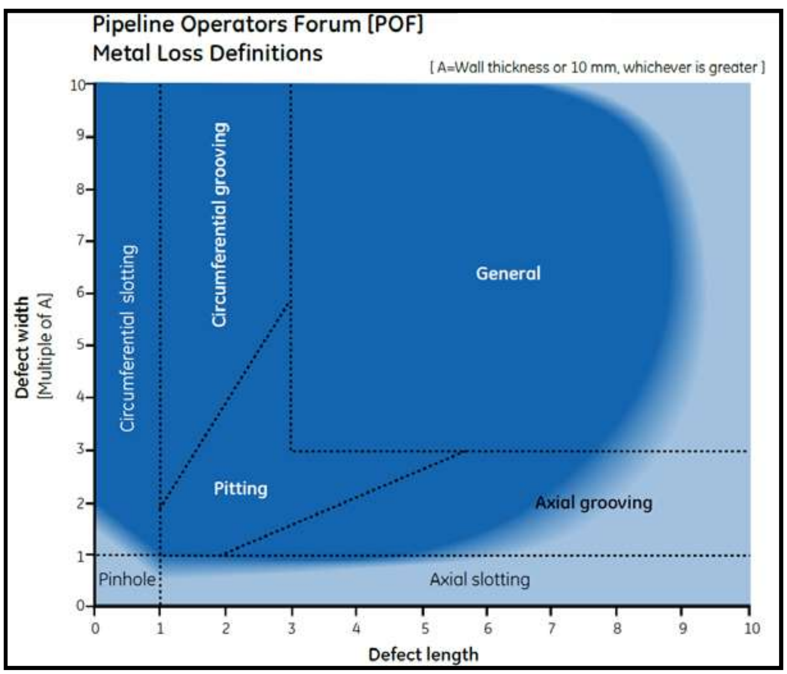

Figure 33 POF Definitions of Metal Loss Anomaly Classes and Detection Capability for Conventional MFL Tools[61]

[61] GE PII Marketing Brochure *PII_MetalLoss_JV_112514.PDF*

An incremental improvement in detecting some anomalies can be achieved with ILI tools that measure all three components of the magnetic field, referred to by the inspection vendor as triaxial sensors. As shown in Figure 34, this sensor configuration improves detection of axial slotting and grooving. However, the anomaly that failed had dimensions that would fall into the lighter blue regions for either conventional or triaxial MFL sensor configurations and therefore would have been challenging regardless of the MFL technology used.

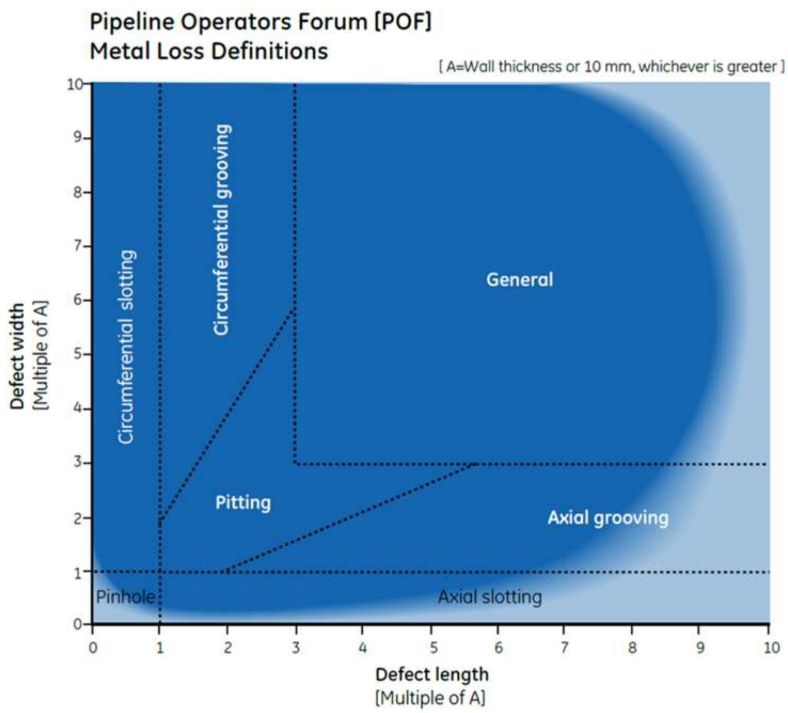

Figure 34. POF Definitions of Metal Loss Anomaly Classes and Detection Capability for MFL Tools with Triaxial Sensors

The fundamental principles of MFL technology provide reasons why long, narrow anomalies are challenging to detect. The basic principle is that magnetic flux would rather stay in the pipe wall than leak out. Yet, for an MFL tool to detect metal loss, the magnetic flux must exit (leak out of) the pipe material. Leakage occurs when the flux is diverted by a change in the pipe wall, such as metal loss. For wider anomalies, the flux path around the anomaly becomes too long and leakage out of the pipe becomes the path of least resistance. However, for long, narrow metal loss, as was found at Ludden +17, the easier flux path is around the sides of the anomaly so that the flux remains in the pipe wall. MFL technology is also challenged by long defects (more than 10 wall thicknesses) regardless of width. For these anomalies, there is more flux leakage at the edges of the anomaly, but less leakage in the middle of the anomaly. The long (in aggregate) nature of the anomaly that failed is one possible reason that both the 2012 and 2016 MFL inspections did not report this anomaly.

Another possible reason that the MFL ILI did not report this anomaly is that the construction equipment displaced metal on the surface of the pipe rather than removed it. In other words there was no net metal loss. As shown in Figure 35, it appears as if metal was moved in several locations rather than removed. The red, curved lines in Figure 35 represent the nominal outer surface of the pipe. The image shows that the equipment that damaged the pipe plowed a series of furrows with decreased wall thickness followed by ridges of increased wall thickness. Wall thickness measurements show a minimum wall thickness of 0.370 inch and a maximum wall thickness of 0.400 inch. If the furrows and ridges were nominally aligned with the flux direction, then the ridges can carry the flux displaced by the furrows and the effective metal loss signal would be negligible for a traditional MFL tool.

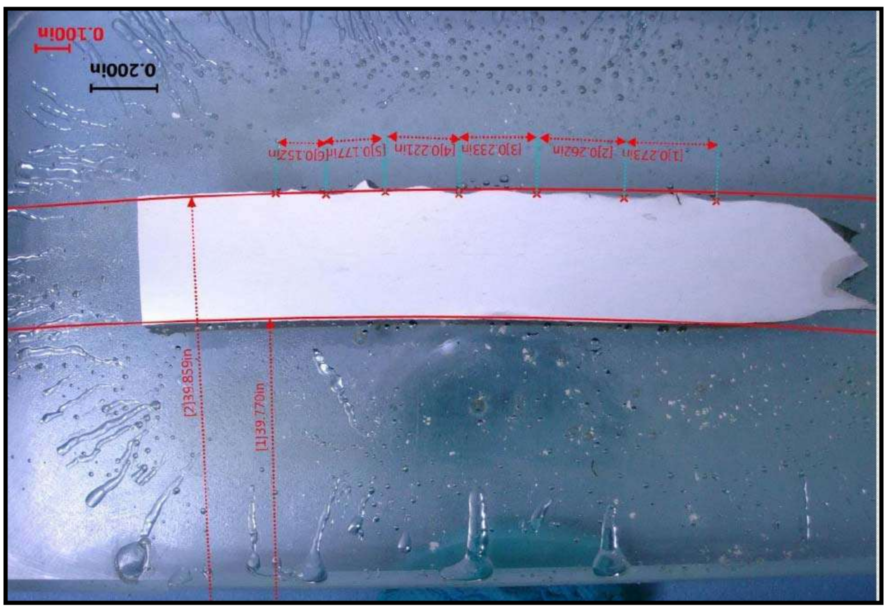

Figure 35. Cross Section of Anomaly Showing Displaced Metal

The furrows and ridges were at a slight angle to the pipe axis, about 10 degrees. If the furrows and ridges were circumferentially aligned, perpendicular to the magnetic flux direction, the ridges would carry negligible magnetic flux and the effective metal loss reported would be the wall thickness of the furrows. Figure 36 shows that the flux leakage amplitude for a long, narrow metal loss anomaly does not increase significantly below an angle of 22.5 degrees, doubles at an angle of 45 degrees, and is six times larger when perpendicular to the direction of the magnetic flux. Therefore the slight angle of the sliding contact marks found at Ludden +17 would not have improved its detectability. Figure 36 shows three sensor orientations, the same sensor configuration used on the tools run on Keystone.

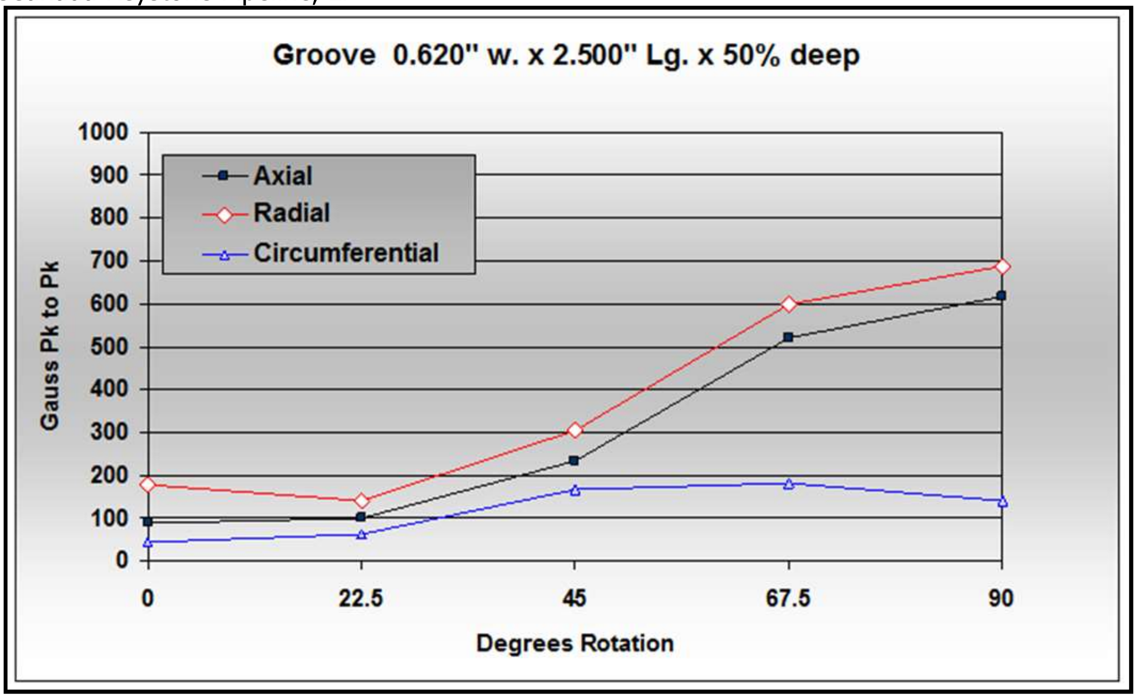

Figure 36. Flux Leakage Amplitude as a Function of Angle for Long Narrow Metal Loss [62]

Even though multiple ILIs were conducted along Spread 2A, the types of tools used by TransCanada and required by the Special Permit were not capable of finding the mechanical damage or cracking that occurred on pipe joint 857504. If other tools such as circumferential MFL (CMFL) or low-field MFL were run, they may have detected the mechanical damage or the associated cold work. Alternatively, if an ultrasonic crack detection (UTCD) tool were run it likely would have detected the subsequent fatigue cracking. Not recognizing the potential for fatigue crack growth in mechanical damage that does not exhibit appreciable denting and not implementing ILI tools to address this threat was determined to be causal to this incident. There is a PIO for TransCanada to enhance their IMP to baseline newly constructed pipelines with ILI tools capable of detecting flaws that do not exhibit appreciable metal loss or denting. Recognizing this gap, TransCanada chose to run GE's UltraScan CD+ tool subsequent to the failure to find axial cracking damage at other locations along Spread 2A. Additionally, TDW's multi-data set (MDS) tool was run in KS6 (spanning the majority of spread 2A) to determine if additional mechanical damage, that may give rise to cracking in the future, was present.

[62] James Simek, "Modeling and Results for Creating Oblique Fields in a Magnetic Flux Leakage Survey Tool", Proceeding on Quantitate Nondestructive Examination, QNDE 2009, August 2009.

3.6.2.5 Damage Not Discovered during Aboveground Surveys (Confirmed, but not Causal)

TransCanada conducts regular aboveground surveys to monitor cathodic protection (CP) effectiveness for corrosion control. Additionally, the Special Permit required that a close interval survey (CIS) be performed on the Keystone pipeline within two years of its in-service date and integrated with the baseline ILI to determine whether further action is needed to control corrosion. TransCanada conducts CP surveys on a yearly basis and performed a CIS combined with a DCVG survey in October 2010, well within the timeframe specified in the Special Permit.

Generally, complementary indirect inspection techniques are performed concurrently so that the strengths of one tool can compensate for the limitations of the other tool. CIS and DCVG surveys are complimentary in that CIS indicates the level of CP on the pipeline and DCVG indicates coating holidays or defects. None of the aboveground surveys indicated issues that could be related to the coating damage in the area of the failure.

The investigation team collected data to understand why these surveys did not indicate issues outside of acceptable limits which could be indicative of missing coating caused by mechanical damage. As will be discussed, the DCVG survey did note a small indication directly above the failure location but because it was below actionable levels, remediation activities were not performed. The October 2010 DCVG indication does narrow the timeline of when the mechanical damage could have occurred, sometime between final jeeping on November 7, 2008 and October 30, 2010, an approximately two-year window.

3.6.2.5.1 Damage not Detected During DCVG Survey (Confirmed, but not Causal)

A DCVG survey was conducted October 30, 2010. DCVG is routinely used to locate coating faults by measuring the voltage gradient created in the soil due to the passage of current from the anode bed through the resistive soil to the bare steel exposed at a coating fault. The voltage gradient surrounding each coating fault becomes larger and more concentrated the greater the current flow and the surveyor’s proximity to the actual fault. In general, the larger the coating fault, the greater the current flow and hence the larger the voltage gradient. The voltage gradient is described in terms of %IR which provides a relative ranking of the seriousness of a coating defect. Generally the higher the %IR measurement, the larger the coating fault. TransCanada specifies that values greater than 35% IR require immediate action, values between 16% and 35% IR require monitoring, and values less than 15% IR are considered minor coating faults that do not require repair, which aligns with industry practice. TransCanada has also implemented a more stringent requirement where a 10% IR or greater indication coinciding with a top side dent would require immediate action.

At the location of the failure, the DCVG survey noted a 2% IR indication (see Figure 37). The size of this indication was not actionable according to either criterion, even if denting was reported by the caliper survey, which it was not.

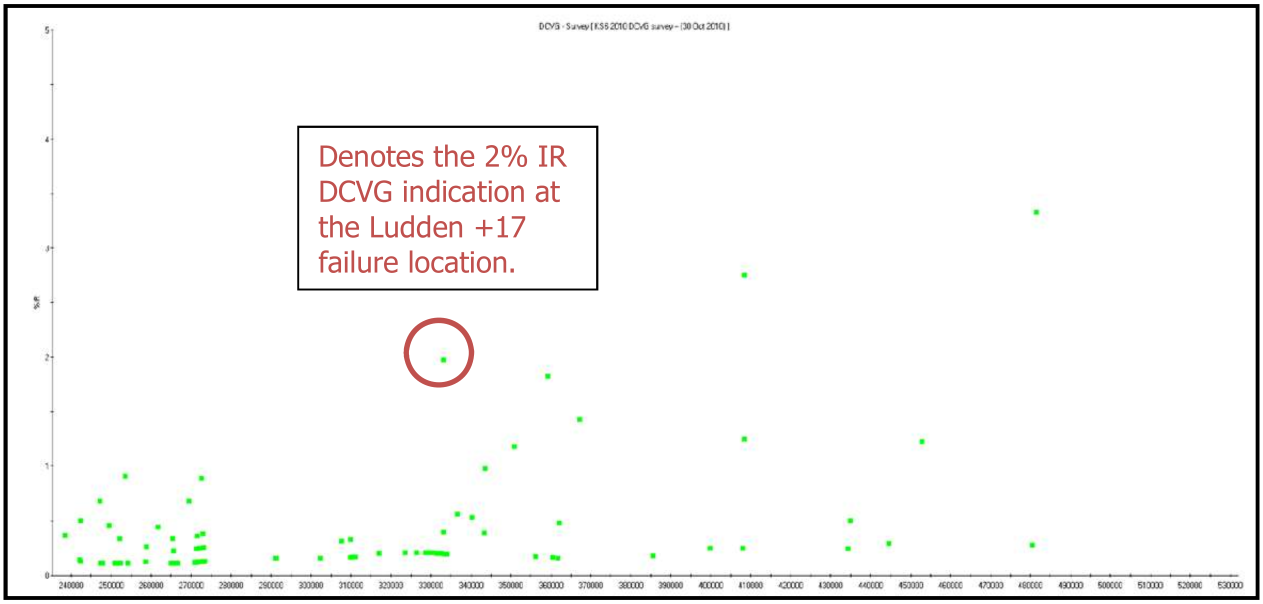

Figure 37. October 30, 2010 DCVG Survey Findings. The location of the failure is at virtual pipeline model distance from start 332,979.7 ft.

DCVG indications can be affected by factors such as the shape and orientation of the coating fault, surface films on exposed steel, local variations in soil resistivity, and depth of the defect[63]. Local soil resistivity near the coating defect is inversely proportional to the IR indication where high local resistivity near the coating defect will result in a much lower %IR. The set-on concrete weights presented an area of locally high resistivity which may have suppressed the %IR signal during a DCVG survey. Similarly, burial depth could have also reduced the %IR signal. Per the Special Permit, Keystone was required to have a depth of cover of four feet as opposed to the more common 49 CFR 195 regulatory requirement of three feet. At the location of the failure, the pipeline was actually at a burial depth of approximately six feet so that the depth of cover over the set-on concrete weights achieved four feet. The %IR reading at six-foot depth could potentially be half of the %IR reading at a three-foot depth[63]. The combined effect of higher local resistivity from the concrete weights and a six-foot burial depth could have reduced the DCVG %IR reading making the coating fault appear to be less significant than what was actually discovered. The exact impact is unknown and may still have been below the reporting thresholds. Therefore DCVG not indicating an actionable coating fault was eliminated

[63] Xu, Xiaoda, DCVG %IR for Coating Defects Assessment, Impact of Burial Depth and Soil Resistivity.

as a causal factor. As an item of note TransCanada should consider the impact of burial depth and local areas of high resistivity on DCVG results.

3.6.2.5.2 Damage not Detected during Close Interval Survey (Confirmed, but not Causal)

As required by the Special Permit, an initial CIS was conducted October 30, 2010. These results were integrated with the baseline ILI data to determine whether any action was required to mitigate external corrosion along Keystone Phase 1. As shown in Figure 38, the lowest CP OFF potential measured within 500 feet of the release location was -1,114 mV which exceeded the minimum instant-off criterion of -850 mV per NACE SP 0169[64]. At the location of the mechanical damage feature, there were no localized dips in the CIS potential profiles which would have indicated the presence of poor quality coating. The difference between the ON and OFF potential was also fairly constant which would indicate a good distribution of protective current along the pipeline.

As discussed in Section 3.6.2.4, neither the 2012 nor 2016 ILI identified metal loss in excess of 10% WT in depth, or with a FPR less than 1.42 within 500 feet of the release location. Even though the set-on concrete weights can act as a localized area of high resistivity potentially shielding CP, the results of both the CIS and ILI show that corrosion was not a concern at the failure location. This was also confirmed by the metallurgical analysis which did not find any evidence of external corrosion within the mechanical damage area.

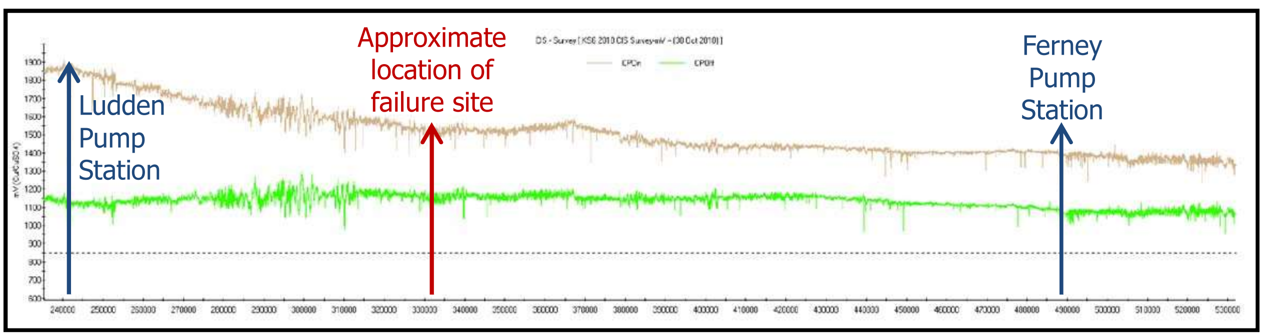

Figure 38. October 30, 2010 CIS Findings. The location of the failure is at virtual pipeline model distance from start 332,979.7 ft.

The CIS results integrated with the ILIs and metallurgical analysis confirmed that CP was protecting the pipe at the failure location and therefore was eliminated as a causal factor.

[64] NACE SP0169-2007, Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

3.6.2.5.3 Damage not Detected during CP Test Lead Surveys (Confirmed, but not Causal)

According to 49 CFR 195.573(a)(1) operators must determine if the CP system meets the requirements of NACE SP 0169 by conducting tests at least once per calendar year, not to exceed 15 months. TransCanada has been conducting annual CP surveys since 2010. The CP OFF potentials at the test leads closest to the failure location (0.67 mile upstream and 1.39 miles downstream) have consistently exceeded the NACE SP 0169 criterion of -850 mV OFF potential.

The CP survey results combined with the lack of corrosion found during ILIs and the metallurgical analysis did not indicate any integrity concerns at the failure site. The CP surveys not indicating a problem with corrosion protection at the location of the mechanical damage feature was found not to be causal to this incident.

3.6.3 Mechanical Damage Grew to Failure Event Sequence

As shown in the metallurgical analysis, multiple, near-surface cracks developed in the mechanical damage feature, a string of which coalesced and eventually grew to failure on November 16, 2017. Several possible sequences of causes and effects were postulated to have contributed to the crack growth and failure during operation:

- Pressure cycling (Confirmed, but not Causal)
- High pressure event (Confirmed, but not Causal)
- Temperature cycling (Eliminated)
- External conditions (Eliminated)

Cracking caused by mechanical damage growing to a point of failure sequence is shown in Figure 39 followed by an analysis of potential contributing factors.

[redacted]

Figure 39. Crack Caused by Mechanical Damage Grew to Failure Event Sequence - Cause and Effect Tree

3.6.3.1 Operational Conditions Allowed Damage to Grow (Confirmed, but not Causal)

The Keystone Phase 1 pipeline was designed to operate at 80% of SMYS in rural areas, which exceeds the limit set by current federal regulation 49 CFR 195.106 of 72% of SMYS. To operate at the higher stress level, TransCanada was granted a Special Permit by PHMSA. The Special Permit lists additional conditions to be followed by Keystone over the life cycle of the pipeline related to pipe and material quality, construction quality control, pre-in service strength testing, the SCADA system inclusive of leak detection, operations and maintenance, and integrity management. The Special Permit requires Keystone to more closely inspect and monitor the pipeline over its operational life than similar pipelines installed without a Special Permit. Specific to operations, the Special Permit requires:

- The pipeline operating temperatures to be less than 150°F;
- Mainline pipeline overpressure protection to be limited to a maximum of 110% MOP consistent with 49 CFR 195.406(b);
- A SCADA system to provide remote monitoring and control of the entire pipeline system with a scan rate fast enough to minimize overpressure conditions, provide responsive abnormal operation indications to controllers, and detect small leaks within technology limitations;
- Submission of annual fatigue analysis for the first five years of operation to validate the pipeline reassessment interval for the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data; and
- Determination of the effect of pressure cycles on flaw growth that passed manufacturing standards and installation specifications. This study is to be shared with PHMSA and the findings of which are to be used to determine if an ultrasonic crack detection tool must be launched in that section to confirm crack growth with Keystone’s crack predictive models.

With the additional requirements in place, mechanical damage occurred during construction which was not detected by the quality assurance and integrity management processes in place. Cracking within the mechanical damage grew over time until its failure on November 16, 2017. The below sections discuss the contributing factors that allowed the mechanical damage to grow to failure.

3.6.3.1.1 Pressure Cycling (Confirmed, but not Causal)

The metallurgical analysis conducted by the NTSB identified near-surface cracking within the cold worked areas of sliding contact marks, as shown in the magnetic particle inspection (MPI) images in Figure 40. The initiating feature is shown in Figure 41. Fatigue crack growth is evident in Figure 42.

Fatigue is a process of incremental subcritical crack growth that occurs due to repeated cycles of applied load or stress. Fatigue crack growth is typically apparent on a fracture surface by the presence of "beach marks" of parallel semi-elliptical markings emanating from one or more points of origin. These mark the progression and direction of incremental crack growth. The fracture surface may also exhibit "ratchet marks" which are small ridges oriented in the direction of crack growth, which represent the convergence of portions of the fatigue crack that are not perfectly aligned in the same plane at the point(s) of origin. Prominent beach marks and ratchet marks are visible unaided in Figure 41 and Figure 42. The fatigue crack growth is seen to have originated in a tear or crack at the base of a sliding contact mark.

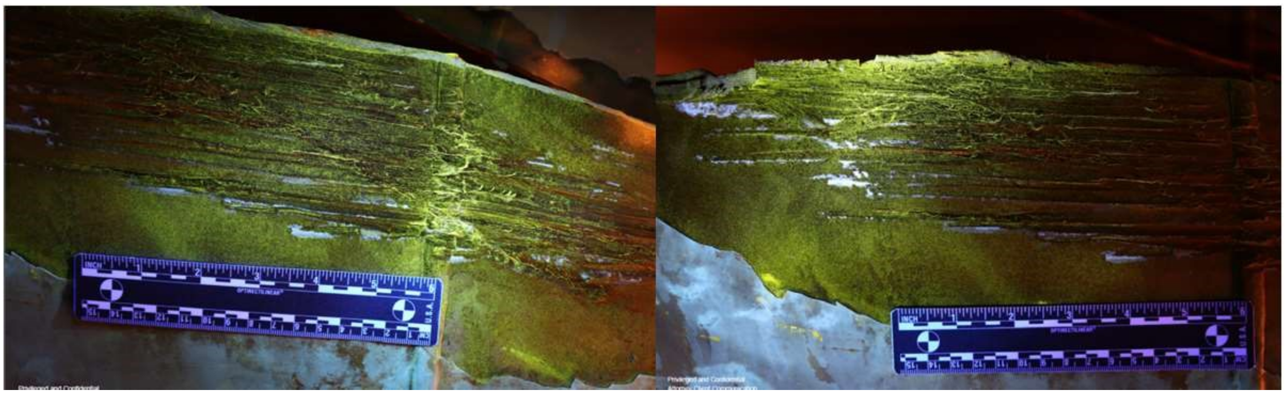

Figure 40. MPI of Sliding Contact Areas

Figure 41. Initiating Feature

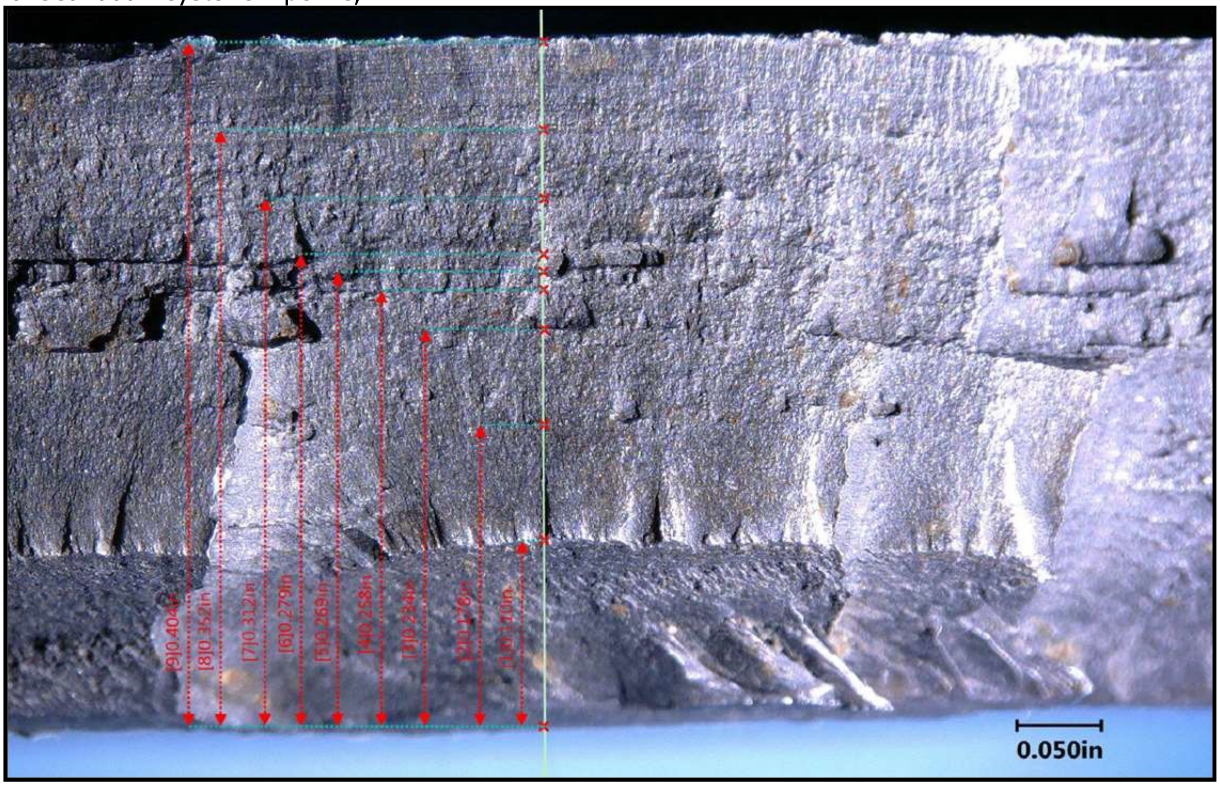

Figure 42. Arrest Line Measurements Indicating Fatigue Crack Growth

The Keystone Special Permit required an annual fatigue analysis to validate the pipe reassessment interval for the first five years of operation. Operation of Keystone Phase 1 commenced on June 30, 2010 and the effect of actual pressure cycles on flaw growth has been performed annually. The objective of the analyses was to determine relative fatigue lives of potentially-existing, longitudinally-oriented manufacturing flaws in the DSAW seam welds using actual worst-case operational pressure cycles and established crack-growth principles. This analysis considered a maximum initial flaw size of 4 inches in length and 0.016 inch in depth based on the detection threshold of NDE tools used to inspect seams at the mill. Using conservative assumptions, the theoretical minimum fatigue life along Keystone Phase 1 was 35 years. This analysis only pertained to manufacturing flaws related to the seam weld and did not consider cracks that may have formed in mechanical damage. The 35-year fatigue life is not applicable to the mechanical damage found at Ludden +17.

[redacted]

Figure 43. Pressure Spectrum for the Ludden Mainline Discharge (PT-0205; LUDDE-A0-PMLD)

Even though the Ludden to Ferney segment is not the most aggressively cycled portion of Keystone Phase 1, the mechanical damage that occurred initiated a crack of sufficient size to grow to failure by pressure-cycle induced fatigue in less than eight years of operation. The time to failure is a function of flaw size and frequency and magnitude of pressure cycles. Because the caliper tool runs did not indicate any denting and the 2012 and 2016 high resolution MFL tool runs did not show any metal loss indicative of mechanical damage, fatigue crack growth in mechanical damage was not considered as a significant threat to the integrity of the Keystone Phase 1 pipeline. As such, there were no requirements in the IMP to run a crack detection tool, CMFL, or low-field MFL tool to detect cold working or cracking related to mechanical damage. Pressure cycling contributed to the failure but was not sufficiently fundamental to be a root cause.

3.6.3.1.2 High Pressure Event (Confirmed, but not Causal)

The Keystone Phase 1 pipeline went into service June 2010 at an MOP of 1,296 psig (0.72 design factor). In November 2014 the maximum allowable discharge pressure at Ludden Pump Station was increased to correspond to an MOP of [redacted] psig (0.742 design factor). In October 2016 the MOP from the Canadian border to the Roswell Pump Station was increased to 1,440 psig (0.80 design factor).

As shown in Figure 44, the discharge pressure at Ludden was operating near the MOP of 1,440 psig (0.80 design factor) from February 2017 through August of 2017. [redacted]

[redacted]

Figure 44. Pressure and Temperature Data for the Ludden to Ludden +23-8 Mainline Valve Segment (2017)

The Keystone overpressure protection control systems are designed using extensive transient modeling to mitigate the potential of an equipment failure leading to an overpressure event. A review of the Ludden Pump Station discharge pressure data leading up to and at the time of the release is shown in Figure 45, which shows no overpressure events leading up to the release. In addition to this, no inadvertent valve closures or issues were experienced at the time of the event which would have led to an overpressure at the location of this release.

At the time of the incident, the Ferney Pump Station was in by-pass mode to allow passage of a cleaning pig and SmartBall® leak detection tool. The increase in the discharge pressure when the downstream pump station is in by-pass mode is a normal operating condition during ILI and the pressures did not exceed the MOP.

[redacted]

Figure 45. Ludden Pump Station Pressure Data

Though the pressure was increasing at the time of the incident, the pressure did not increase beyond the MOP. The fatigue crack had grown large enough to rupture at the operating pressure of approximately [redacted] psig, based on an API 579 Failure Assessment Diagram, Level 2, analysis accounting for actual material properties. Because Keystone was operating as expected during the cleaning tool run and SmartBall® inspection, the high pressure event contributed to the failure but was not sufficiently fundamental to be a root cause.

3.6.3.1.3 Temperature Cycling (Eliminated)

Keystone Phase 1 is restricted to a maximum operating temperature of 150°F by the Special Permit. As shown in Figure 46, the operating temperatures have been maintained below this requirement for the operational life of the pipeline. The temperature varies seasonally and has demonstrated an increasing trend over time which can be tied to the increases in operating pressures and flowrates. ASME B31.4[65] and other pipeline design codes and standards require no derating of line pipe strength at 150°F.

Fatigue crack growth rates are not known to increase with increasing temperature in the range of interest. In fact they have been demonstrated to decrease slightly at temperatures above

[65] ASME B31.4-2006, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.

room temperature,[66] possibly due to dynamic strain-aging effects. Thus operating temperatures are not considered to be a contributing factor.

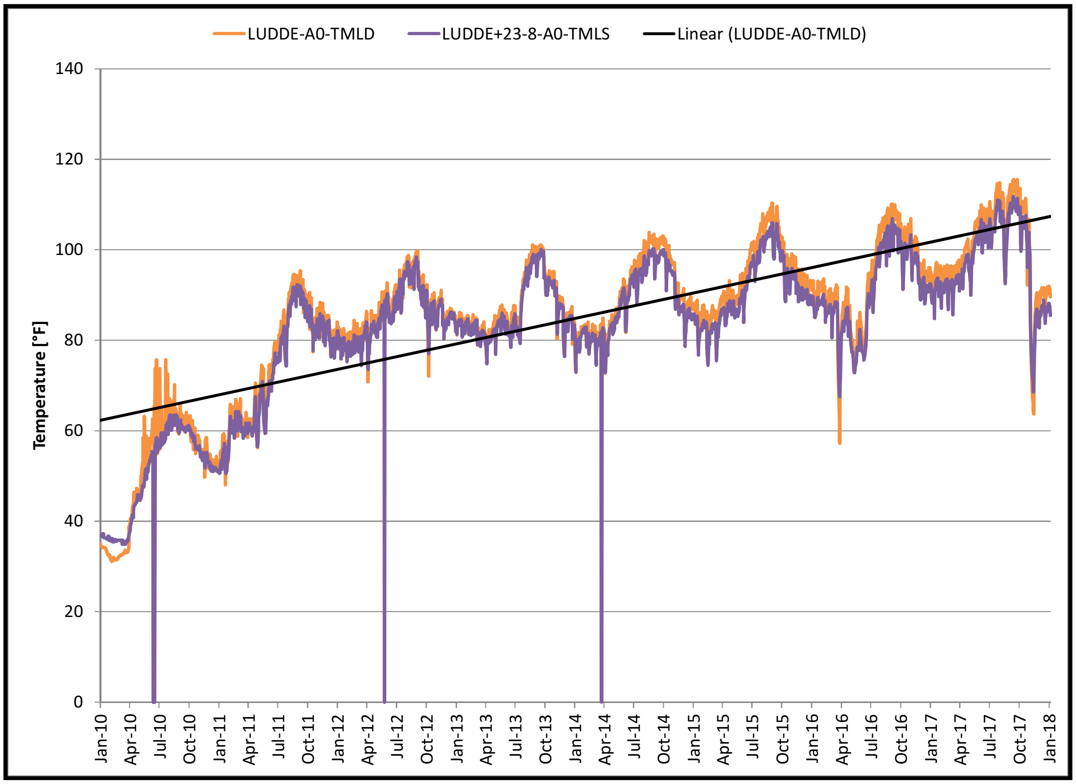

Figure 46. Temperature Data for the Ludden to Ludden +23-8 Mainline Valve Segment (2010 to 2018)

3.6.3.2 External Conditions Allowed Damage to Grow (Eliminated)

Crack growth could have occurred due to external conditions like ground movement, a corrosive environment, or third party damage. As discussed in Section 3.6.1.6, it is unlikely that additional third party damage played a role in crack growth after the initial damage was incurred. Likewise, external loads did not play a role in crack extension. Any effects from a step change in stress would have been seen as ductile tearing on the fracture surface beyond the original crack. These features were not seen in the metallurgical examination and therefore crack extension due to a change in stress did not contribute to this incident. Moreover, the site is not known to be susceptible to geotechnical hazards and land usage at the site is not associated with heavy or frequent external loads from vehicles or equipment crossing the pipeline.

[66] Andreason, D.H., and Vitovec, F.H., "The Effects of Temperature on Fatigue Crack Propagation in Linepipe Steel", Metallurgical Transactions, vol. 5, August 1974.

Additionally, the metallurgical analysis did not find any evidence of corrosion products in the sliding contact marks or cracks. The absence of corrosion was confirmed by the 2012 and 2016 ILI runs as well as the CP test station surveys and CIS showing that the pipeline was adequately protected by CP in the Ludden +17 area. Therefore corrosion growth and stress corrosion cracking (SCC) growth were eliminated as potential contributing factors.

3.6.4 Volume of Crude Oil Released

According to the NTSB metallurgical analysis, the crack that failed had not leaked prior to the pipeline rupture. Therefore the size of the release was dictated by the response of the LDS, the OCC in shutting down and isolating the pipeline, and emergency response team to contain and remediate the spill. The SmartBall® leak detection tool that was in the line at the time of the release as well as the aerial patrol that occurred on November 3, 2017 would not have discovered signs of a release because the line did not leak before the rupture occurred. A leak would have been detectable to the SmartBall® and to the LDS, as will be discussed below.

The components of the leak detection strategy at TransCanada form an overlapping, multilayered approach, including a SCADA system, instrumentation (pressure, temperature and flow meters), a computational pipeline model (CPM), control center (pipeline and dedicated leak detection controllers), aerial patrols, and land owner (public) awareness. Analysis of the LDS components showed that all systems were operating normally at the time of the event.

Several components of Keystone's leak detection systems and response were examined to determine whether their performance contributed to the volume of the release (see Figure 47):

- Release not discovered during internal leak inspections (SmartBall®) (Eliminated)
- Release not discovered during pipeline aerial patrols (Eliminated)
- LDS response issue (Eliminated)
- Control room response issue (Eliminated)
- Emergency response issue (Eliminated)

The investigation team determined that none of the above components were causal to this incident. The LDS, OCC, and response team exceeded expectations and were able to shutdown the pipeline within three minutes of the first indication of the rupture and isolated the pipeline within 12 minutes of the first indication. Prompt notifications were made to the Regional and Corporate EOCs as well as the NRC and PHMSA once the spill location was confirmed.

[redacted]

Figure 47. Volume of Crude Oil Released Event Sequence - Cause and Effect Tree

3.6.4.1 Leak Not Discovered by Internal Leak Inspections (SmartBall®) (Eliminated)

SmartBall® is an in-line acoustic inspection tool used by TransCanada to periodically assess for very small leaks. TransCanada has run SmartBall® through the affected segment every year since 2015. At the time of the Ludden +17 incident, the 2017 SmartBall® run was being conducted and had passed the failure location approximately four hours prior to the rupture on its way to the Ferney Pump Station.

The SmartBall® leak detection technology is stated to have a leak detection threshold of 0.03 gal/min (110 mL/min) which is one of the lowest detection thresholds for pipeline leaks in a non-real time tool. The data were reviewed from the November 15, 2017 run and there was no indication of a leak at the failure location. A potential leak rate was estimated assuming a 1.95 inch long crack (the length of the crack at the ID as discussed in the metallurgical analysis) with a width of 0.01 inch and crude oil specific gravity of 0.8. The estimated leak rate was calculated to be 7.1 gal/min (2.7×10^4 mL/min); more than two hundred times larger than the SmartBall® detection threshold. Based on this analysis, the investigation team concluded that the fatigue crack was not leaking at the time the SmartBall® inspected this location or else it would have been detected and therefore was not causal to the release volume.

3.6.4.2 Leak Not Discovered by Aerial Patrols (Eliminated)

TransCanada conducts an aerial patrol (low level flight) on all sections of the Keystone pipeline ROW every two weeks and nominally 26 times per year. Aerial patrols allow for a visual inspection of the ROW to identify any work occurring on the ROW that is not approved or places where the pipeline has not been located and for identification of potential indications of a release. These flights are completed by a pilot and a spotter. Any potential issues determined to be an immediate response are communicated to the OCC and technicians are deployed to the site for investigation. Immediate response conditions also mandate a review by the pipeline and leak detection controllers for any potential anomalous conditions.

All pilots flying the TransCanada ROW are Operator Qualified, as per regulations, to perform the task of aerial patrol. The re-qualification is completed every three years. Team meetings are used by the chief pilots to share lessons learned from new or distinct events that were reported.

Records from the November 3, 2017 patrol were reviewed and confirmed that there were no indications of a leak, third party activity, or other anomalous conditions in the location of the release. The SmartBall® inspection also confirmed that the damage did not leak prior to rupture and therefore aerial patrols were eliminated as causal to the release volume.

3.6.4.3 Leak Detection System Response Issues (Eliminated)

TransCanada uses a real-time transient model (RTTM) as the primary leak detection method, which is a sophisticated compensated mass balance system and reflects industry best practice for computational pipeline monitoring systems and leak detection for long haul pipelines. The RTTM incorporates the physical properties of batches of oil injected into the pipeline, such as the compressibility, thermal expansion, viscosity and density, which are used in conjunction with measured pressures, temperatures, flow, and other operational variables from thousands of sensors in the field sent to the control room every five seconds to track the batches of oil through the system and more accurately model pipeline operations in real-time. A high level of granularity and robustness of real time analysis was achieved through installation of flow meters at every pump station, enabling detailed segmentation and balance calculations along the pipeline.

TransCanada adheres to a comprehensive and continuous improvement approach to training control center staff to enhance their ability to monitor the pipeline 24 hours a day, seven days a week. TransCanada dedicates a controller on each shift to exclusively monitor the leak detection system. All TransCanada controllers have the authority to shut down the pipeline in accordance with safe shutdown procedures if a leak is suspected or if an abnormal condition cannot be explained.

TransCanada's design and construction practices for Keystone focused on ensuring robust and reliable instrumentation was available to provide the LDS and the control center with detailed, real time information to make informed decisions about detecting leaks in flowing and shut-in conditions. This design placed pressure and temperature transmitters at every remote mainline valve to improve linepack accuracy as well as redundant transducers at key locations. Moreover, ultrasonic flow meters are installed at every pump station to provide accuracy in the pipeline balance.

TransCanada's LDS is state-of-the-art and has been proven to exceed industry standards for detection sensitivity by a factor of two or more (1% of throughput compared with 2% for industry norms). At 5:34 AM central time, the Keystone LDS identified an immediate loss of line pack and flow[67]. The leak flowrate in the affected segment reached a maximum of [redacted] m^3/hr which exceeded the [redacted] m^3/hr threshold over a two minute averaging window (see Figure 48).

[67] TransCanada Keystone Amherst South Dakota Incident Corrective Action Order SCADA Review, Rev 0, Draft.

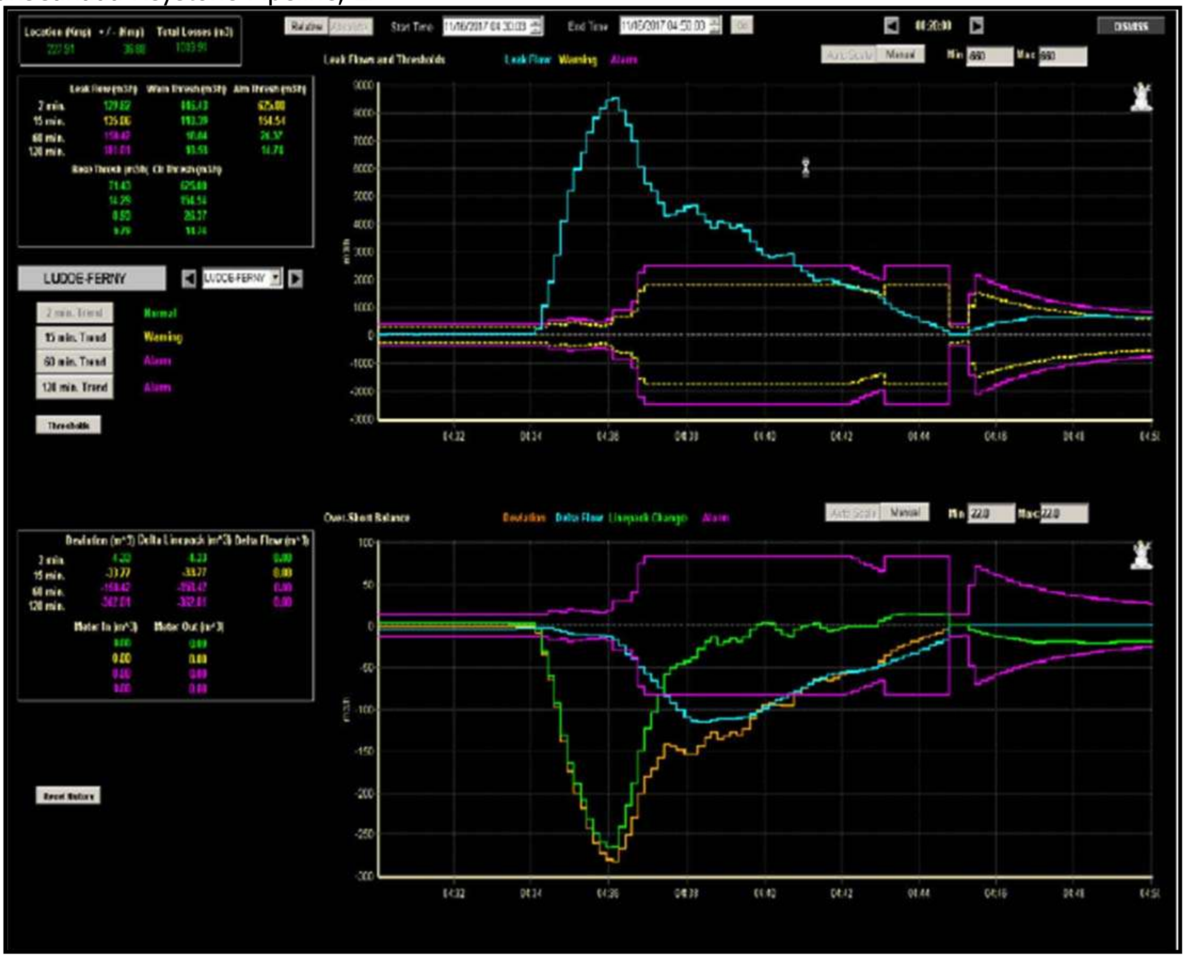

Figure 48. Ludden Pump Station to Ferney Pump Station Simulation Suite Alarm Indications

Witness interviews indicated that all devices within the affected segment were in working order at the time of the release. All transmitters (pressure, temperature, and flow) were checked for false alarms in the segment of concern and no false alarms had occurred.

TransCanada is committed to perform testing of the LDS at least once per year, not to exceed 15 months, using either a full transient hydraulic model to simulate leaks of various sizes and verify system response or through physical withdrawal (initial test was 2015) to measure LDS performance. TransCanada alternates the selected test method each year. According to witness statements the LDS has always successfully completed this testing. No issues were identified during the 2016 hydraulic simulator test. A physical withdrawal test had just been conducted at the Liberty Pump Station in May 2017 and also met all the performance requirements. Flowing and shut-in thresholds were at levels that met or exceeded the leak detection performance as described in the Keystone Pipeline Computational Leak Detection Systems Governance Manual and flowing thresholds exceeded API 1149 Recommended Practice (see Table 4).

Table 4. Steady State Leak Detection Thresholds (2016)

[redacted]

A review of pipeline shut-ins[68] was also performed to determine if the Ludden to Ferney segment could have leaked prior to the rupture on November 16, 2017. Ten pipeline shutdown events and six extended shutdowns were reviewed for any indications of a leak. All extended pipeline shutdowns in the segment of interest showed the same expected decrease in pressure (see Figure 49) that was attributed to thermal cooling. The review focused on pressure decay during shut-in conditions and changes in decay that might be indicative of a leak. No such indications were found.

[redacted]

Figure 49. Scheduled Pipeline Shutdown for 36-Hour Maintenance Window on November 7-9, 2017 (startup 1 week before incident)

[68] TransCanada Keystone Amherst South Dakota Incident Corrective Action Order SCADA Review, Rev 0, Draft.

The review focused on pressure and flow trends during flowing and shut-in conditions, SCADA events and alarms, and LDS events in the Ludden to Ferney segment from the time of the incident back until June 2017. This review did not reveal any indications of a leak in the historical data prior to the rupture at 5:33 AM central time on November 16, 2017 and therefore was eliminated as a potential causal factor to the release volume.

3.6.4.4 Control Room Response Issues (Eliminated)

On November 16, 2017, at 5:33 AM central time, the Keystone SCADA system detected a pressure drop at LUDDE+23-8. One minute later the SCADA system detected a pressure drop and increase in flow at the Ludden Pump Station and a pressure drop at Ferney Pump Station (see Figure 50). The Ferney Pump Station had been placed into by-pass mode at 5:24 AM central time, nine minutes before the rupture occurred. Corresponding drops in pressure and flow were seen at the upstream pump station (Fort Ransom) and the downstream pump station (Carpenter) approximately two minutes later.

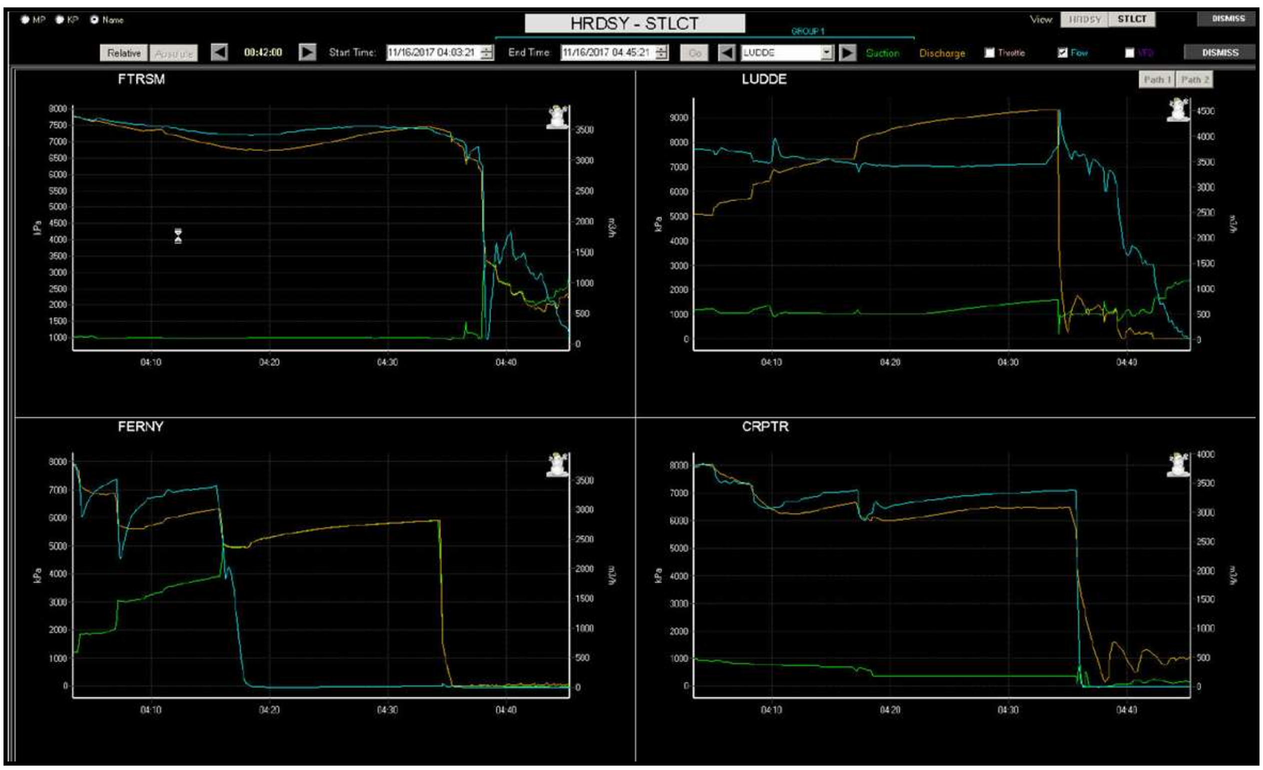

Figure 50. SCADA Screenshots at the Fort Ransom, Ludden, Ferney, and Carpenter Pump Stations at the Time of the Incident (time scale is Mountain Time zone)

At 5:34 AM a low suction alarm and Unit A2 SDR ALM sounded followed by an LDS alarm between Ludden and Carpenter indicating a 2-minute flow of [redacted] m^3/hr and peak flow of [redacted] m^3/hr. Within 44 seconds of receiving the leak alarm, the controller began to shut down the pumps at Hardisty and Lakes End. By 5:44 AM central time Ludden, Ferney, and Carpenter were sectionalized and at 5:45 AM mainline valves LUDDE+23-8, FERNY+14-3, and CRPTR+15-7 were closed. By 5:49 AM Fort Ransom was sectionalized and FTRSM+9-5, FERNY+30-8, and FTRSM+31-7 mainline valves were closed (see Figure 51).

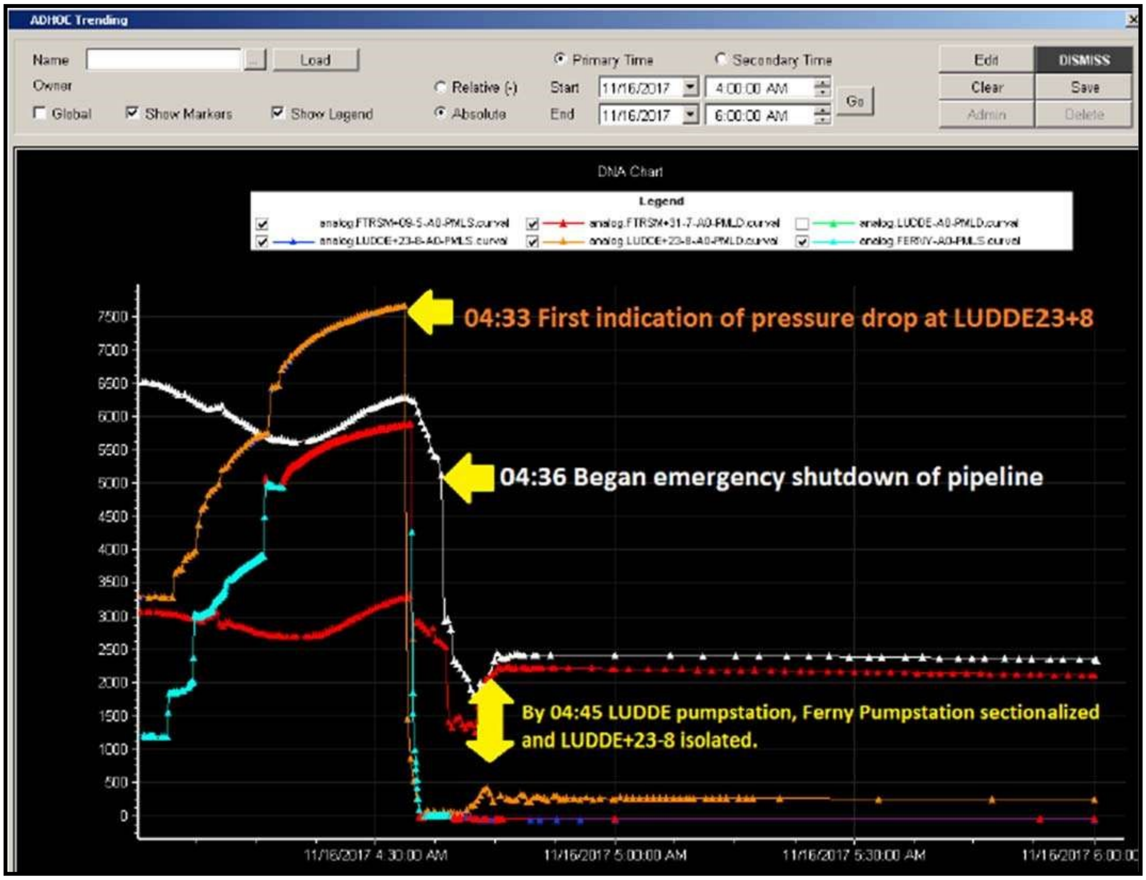

Figure 51. Pressure Trends in the Ludden to Ferney Segment (time scale is Mountain Time zone)

The SCADA timeline and actions taken by the control center prior to and during this event were reviewed. This review showed that all control center actions were in line with best practices and TransCanada's procedures[69]. No delays in responses were found whether from initial notification to shutdown; shutdown to isolation; isolation to notification of field technicians; or in initiation of the Emergency Operations Center (EOC) through the Emergency Operations Manager. Even though the event occurred toward the end of the night shift, when fatigue would have been at its highest, the control room performance exceeded expectations. For these reasons the control room response was eliminated as a causal factor to the release volume.

[69] TransCanada Emergency Management Corporate Program Manual, Rev 18, June 30, 2015
Keystone Pipeline System Emergency Response Plan, Rev 1, September 30, 2015
Oil Pipelines Emergency – Critical Task Directive, Rev 3, November 9, 2011

3.6.4.5 Emergency Response Issues (Eliminated)

The emergency response was managed by TransCanada personnel and contractors, with security and logistical support provided by local law enforcement, fire service, and emergency management. TransCanada is currently performing an internal review of the emergency response which will be presented to PHMSA in a separate document.

4 SUPPORTING INVESTIGATIONS

4.1 Metallurgical Analysis

The NTSB performed a metallurgical failure investigation of the failure. The investigation included standard failure analysis examinations and tests including visual examination, fractographic examination by optical microscopy and scanning electron microscopy (SEM), surface analysis using EDS, metallographic sectioning, and material properties tests.

The NTSB investigation determined that the pipe was affected by mechanical damage consisting of several parallel contact marks or grooves of unspecified cause on the exterior surface of the pipe. The pipe ruptured due to a crack that originated at a tear or crack within one of the damage features and that enlarged in service by fatigue.

The metallographic examination identified foreign metal transfer onto the surface of many of the damage features. The transfer material was confirmed to be foreign by the presence of chromium in concentrations not present in undamaged pipe material. The surface analysis identified no evidence of transfer material from the nearby buoyancy control weight.

Standard material tests demonstrated that the pipe material met the applicable specifications for mechanical strength, impact fracture toughness, and steel chemistry.

4.2 Personnel Interviews

Members of the investigation team visited the release site during the incident response to view the location of the failure as well as the surrounding terrain.

The team conducted numerous interviews with construction personnel and contractors, operations and integrity personnel, emergency response personnel, and regulatory compliance personnel to gain an understanding of the sequence of events that led to the mechanical damage on pipe joint 857504, the circumstances around why the damage was not detected, what led to the release, as well as the effectiveness of the shutdown and response. Lines of questioning included the timing of events, location of personnel, events during construction, operation, and system maintenance, environmental conditions, response to abnormal events, emergency response activities, similar previous incidents, and possible causes, beliefs, opinions and judgments related to the incident. Interviewees were asked about their background, experience, job duties, qualifications, and training. Interviews also included discussions related to TransCanada's policies, procedures, and safety culture.

The investigation team interviewed the following personnel.

Design and Construction

[redacted]	TransCanada	US Projects and Technical Services
Bob Osborn	Contractor	Construction Contractor
David Bristol	Contractor	Construction Contractor
Charlie Hankins	Contractor	Pipe Receiving
MacNeil Mercer	Contractor	Pipe Receiving
Bruce Munro	Contractor	Pipe Receiving
Buster Gray	Contractor	Keystone Phase I Engineering and Construction

Operations

[redacted]	TransCanada	Liquids US Operations
[redacted]	TransCanada	Liquids US Operations
[redacted]	TransCanada	Liquids Pipeline System Control
[redacted]	TransCanada	Leak Detection Engineering
[redacted]	TransCanada	Leak Detection Engineering

Integrity

[redacted]	TransCanada	Pipe Integrity Engineering
[redacted]	TransCanada	Pipe Integrity and Damage Prevention

Emergency Response

[redacted]	TransCanada	Liquids US Operations

Regulatory Compliance

[redacted]	TransCanada	US Regulatory Compliance
[redacted]	TransCanada	US Regulatory Compliance

4.3 Reported Similar Incidents

4.3.1 Bison Mechanical Damage Failure

A failure occurred on TransCanada's Bison Natural Gas Pipeline on July 20, 2011. The failure originated at a 6.4 inch long area of mechanical damage located near the top of the pipe. The total extent of mechanical damage at the failure origin was approximately 13 inches. The mechanical damage removed up to 11% of the pipe wall thickness. Re-rounding cracks to a maximum depth of 14% of the pipe wall thickness developed in the mechanical damage that propagated to failure in less than seven months of operation. The pipe specimen met the requirements of API 5L, 43rd Edition for Grade X70 welded line pipe.

TransCanada tightened their response criteria for DCVG indications based on findings from this failure investigation. Any top side dent, regardless of size, combined with a 10% IR or greater indication from DCVG is excavated. Even with the more stringent criteria, the mechanical damage at Ludden +17 would not have met this criterion because denting was not reported by the caliper survey and the DCVG indication was only 2% IR.

5 Conclusions and Recommendations

5.1 Conclusions

The loss event was defined as: rupture of pipe joint 857504 leading to the release of an initially reported volume of 5,000 barrels of crude oil. Causal factors were recognized for event sequences pertaining to (1) mechanical damage to the pipe joint and (2) the damage to the pipe joint remaining undiscovered. Contributing factors were identified related to the damage growing to a point of failure. The investigation also evaluated the control room response and pipeline isolation which limited the volume of the release.

Safeguards are physical, administrative, and procedural barriers or controls that are in place to prevent and incident from happening. Although all applicable codes and regulations were met through design and implementation, mechanical damage to the pipe occurred during construction and remained undiscovered post-construction because several safeguards were insufficient. These safeguards included:

- Supervision, inspections, and procedures during pipe installation (causal factor),
- Commissioning hydrostatic test (damage not detectable),
- Commissioning caliper survey (damage not detectable),
- Aboveground CIS and CP test lead surveys to detect inadequate CP (damage not detectable),
- Aboveground DCVG survey to detect coating holidays (damage indication not actionable), and
- In-line Inspections (causal factor).

For each safeguard, several contributing factors to the damage initiation, lack of detection, and growth to failure were identified and summarized below.

5.1.1 Mechanical Damage to Pipe Joint 857504 Occurred

Several possible sequences of causes and effects were postulated to have contributed to the occurrence of mechanical damage on pipe joint 857504 related to damage occurring (1) at the pipe mill; (2) during pipe shipping, receiving, or storage; (3) during pipe installation; or (4) during operations.

5.1.1.1 Damage Occurred at the Pipe Mill and Not Discovered (Eliminated)

A review of the MTRs for pipe heat W8E596, the NTSB metallurgical analysis, and the pipe receiving inspection reports at the Englevale, ND railyard indicated:

- The steel slab used for the pipe in heat W8E596 was fully killed, continuously cast and thermo-mechanically control-rolled steel which met the requirements of the Special Permit.
- The pipe in heat W8E596 was manufactured to API 5L, PSL 2 requirements for Grade X70 pipe, as required by the Special Permit.
- The pipe met the fracture control requirements in the Special Permit, API 5L 43rd Edition, and TransCanada's pipe specification TES-PIPE-SAW-US.
- The entire external surface of the pipe in heat W8E596 was visually inspected and was non-destructively evaluated in accordance with acceptance standards CSA Z245.1-07, API 5L 43rd Edition, and TES-PIP-SAW-US.
- The MTR showed that the pipes in heat W8E596 were hydrostatically tested at the mill to a pressure of [redacted] psig (90% of SMYS) for 10 seconds and no failures were indicated. Even though the Special Permit and TES-PIPE-SAW-US required the pipe to be tested at the mill to [redacted] psig (95% of SMYS) or greater for 10 seconds, the fact that the pipe was only tested to 90% of SMYS has no bearing on this investigation. The pipe was later tested to 100% of SMYS during the commissioning hydrostatic test without failure.
- The NTSB metallurgical analysis showed evidence of contact on the exterior surface of intact coating and curling of coating near the sliding contact marks. Therefore, the damage had to occur after the FBE coating was applied at the mill.
- Pipe was transported according to API 5L1 requirements.
- Visual inspections upon receipt of railcars containing pipe from heat W8E596 did not note any pipe damage.

Since the evidence indicated that the damage to pipe joint 857504 occurred during installation activities and the pipe properties met all the manufacturing specifications, no causal factors were found related to pipe damage occurring at the pipe mill.

5.1.1.2 Damage Occurred During Shipping, Receiving, or Storage and Not Discovered (Eliminated)

A review of the receiving inspection reports at the Englevale, ND railyard and witness interviews indicated:

- Per contractual documentation, TransCanada and the contractor witnessed delivery of all material and visually inspected it for quantity and condition with both signing off on the written documentation.
- Visual inspections upon receipt of railcars containing pipe from heat W8E596 did not note any pipe damage.
- Witness statements indicated that the storage yards complied with specifications outlined in contractual documents requiring gravel pads to minimize issues with muddy conditions. The storage yards also had site security to reduce the potential for vandalism.
- Pipe along Spread 2A was offloaded with vacuum lifts which complied with contractual requirements and minimized the opportunity for pipe damage to occur. The contractor only recalled damaging one joint of pipe in their care for the entire Keystone Phase 1 project, which was removed and destroyed.
- Inspectors received an orientation on Keystone, the Quality Manual, and construction specifications prior to commencing work.

Since the evidence indicated that the damage to pipe joint 857504 occurred during installation activities, no causal factors were found related to pipe damage occurring during shipping, receiving, or storage.

5.1.1.3 Damage Occurred During Pipe Installation (Causal Factor)

5.1.1.3.1 Damaged During Stringing and Welding (Eliminated)

A review of the procedures and practices that occurred during pipeline stringing and welding for Spread 2A indicated:

- The pipe materials selected and used to construct Spread 2A were appropriate for the defined application and met API 5L PSL2 specifications.
- Pipe damage was not noted on either the Pipe Coating/Jeeping or Welding Inspector's Reports but it was also not a specific question on the forms. If damaged pipe was found by the stringing inspector, it should have been recorded on the Damaged Pipe Report and set aside for repair or returned.

- The damage to the coating would have been easily detected with properly functioning holiday detection equipment and trained inspectors as well as visually detected if the pipe had been damaged prior to lowering-in.

Since the evidence indicated that the damage to pipe joint 857504 occurred after lowering-in, no causal factors were identified related to pipe damage occurring during stringing and welding.

5.1.1.3.2 Damaged During Trenching, Lowering-in, and Weight Installation (Inconclusive)

A review of the procedures and practices that occurred during pipeline trenching, lowering-in, and weight installation for Spread 2A indicated:

- TransCanada implemented a Construction Quality Manual and provided training to inspection contractors. The quality manual contained very specific requirements for the multiple inspectors involved in the construction of Keystone Phase 1.
- TransCanada implemented Construction Procedures (Exhibit B) that were included in contractual documentation covering all aspects of construction including trenching, lowering-in, and buoyancy control.
- According to witness statements, the design team collected soils data at the pump stations and river crossings but not along the length of the pipeline unless dictated by specific engineering requirements. Instead, the design team made use of publically available soils data from agencies like the USGS as input into the pipeline design. Based on the input data used, the issued-for-construction alignments sheets did not include the installation of buoyancy control measures near MP 234.
- Fall 2008 was wetter than normal in northeastern South Dakota causing the water table to be very high along the construction ROW. For this reason, it was decided in the field to add buoyancy control at several locations along Spread 2A, including near MP 234.
- The addition of buoyancy control required the trench to be excavated deeper to allow for four foot DOC above the concrete weight. According to witness statements, the construction crew may have been performing side-digging to achieve the required DOC after the pipe had been lowered into the ditch. Witness statements indicated that they would not dig along the pipeline if it was not visible (i.e. the trench was filled with water). Instead, they would dewater the trench which was indicated on the daily construction progress report.
- The environmental conditions along the ROW were extremely challenging on the day the pipe was lowered-in which affected construction progress. The trench was sloughing making it difficult to maintain the additional depth.

- The pipe was inspected with a holiday detector (jeeped) prior to lowering-in. Other than a note on the Lower-in Inspector's Daily Report that jeeping was performed, no additional records were found regarding calibration of the holiday detection equipment, the inspection parameters, or results from the inspection on the day that pipe joint 857504 was lowered in.
- The location of the mechanical damage was within approximately one foot of a concrete weight; however, the NTSB metallurgical analysis confirmed transfer of metal higher in chromium content to the pipe in the sliding contact areas indicative of damage caused by construction equipment and not the concrete weight.
- Although it could not be confirmed, the visual appearance of the mechanical damage is more consistent with the repeated motion of equipment that was rotating, such as the cleats of tracked equipment, rather than repeated impacts from a backhoe bucket. Witness statements also confirmed that the teeth on the bucket would likely have had a bar welded across if digging near the pipeline to prevent damage and that the bucket most likely would have been positioned perpendicular to the pipe when digging the trench which is inconsistent with the axial appearance of the mechanical damage.
- Witness statements indicated that visual inspections were conducted after the pipe was lowered-in, during weight installation, and during backfill activities. However, the inspector's daily reports did not have check boxes or specific areas for the inspector to note that visual inspections were performed or the results of those inspections aside from reporting if there were any non-conformance issues.

Root causes were identified for this causal factor related to incomplete consideration of the potential hazards during installation of buoyancy control in muddy, wet conditions in company SPAC, the potential need for additional supervision and inspection under the specific ROW conditions encountered at Ludden +17, and the SPAC lacking appropriate detail to ensure that the Construction Quality Manual was being followed. Potential improvement opportunities (PIO) were identified for inspection documentation and the use of site specific soils data during the design phase.

5.1.1.3.3 Damaged During Backfill and Rough Cleanup (Inconclusive)

A review of the procedures and practices that occurred during backfill and rough cleanup for Spread 2A indicated:

- Backfill occurred November 8, 2008, one day after lowering-in and the ROW remained muddy and wet.

- The Padding/Backfill & Clean-Up/Restoration Inspector's form indicated padding, rock shield, imported fill was installed as required. Soil in this location is not rocky as documented in construction photographs.
- The ROW conditions were such that it was possible for equipment to sink and get stuck in the mud during backfill. Therefore, it is plausible that as a dozer was working to achieve the DOC during backfill that the blade could have been resting on top of the concrete weight and the back of the dozer sunk down enough to contact the pipe with its track between the weights. Because, the DOC in this location was six feet and the damage occurred in close proximity to a concrete weight, this would have had to occur prior to achieving the full DOC.
- Pipe inspections during backfill activities were performed when the pipe was still visible, damage occurring after the pipe was partially covered would not have been detected.
- It is company policy that dozers are not permitted to operate over the pipeline during backfilling, so the postulated damage scenario would be contrary to that policy.

The investigation team was not able to conclusively determine if the damage occurred during trenching, lowering-in, and weight installation activities or during backfill activities. Regardless, causal factors were determined associated with equipment working along the ROW damaging the pipe. The wet, muddy conditions during backfill made work along the ROW more difficult with an enhanced potential for equipment to become stuck in the mud. Additional inspections were not implemented to compensate for difficulties encountered under the adverse work conditions. As such, the root causes that allowed pipe joint 857504 to be damaged are the fact that the SPAC did not adequately address the conditions that were experienced during backfill including the need for additional pipe inspections to detect mechanical damage after the pipe was covered.

5.1.1.3.4 Damage Occurred During Cleanup and Final Restoration (Eliminated)

The review of final cleanup and restoration inspection reports for the Ludden +17 location and witness statements indicated:

- The Keystone Construction Specifications required compacted soil to be ripped at least 18 inches deep in cropland and 12 inches deep for pasture and woodland using a paraplow or equivalent non-inversion, deep tillage implement. This activity was to be performed with at least three passes.
- Muddy ROW conditions were confirmed in daily inspection reports when final cleanup and restoration activities were conducted nearly a year after the pipe at Ludden +17 had been lowered-in (September 26, 2009). Muddy soil can be 'soft' and may allow

equipment traversing the pipeline ROW to sink. However, based on witness statements, the equipment used to restore the ROW would likely have been rubber tire or rubber tracked farm tractors pulling paraplows and tracked dozers. It is unlikely that the multiple, narrow scrapes found could have been caused by the tractor and because of the concrete weight placement it is unlikely that the tracks from a dozer could have sunk down enough to cause damage so close to the weight.

- Witness statements also indicated that the cleanup and restoration tractors do not have the horsepower to pull soil ripping implements through six feet of soil cover.
- If an extended period (> 2 months) elapsed between initial and final cleanup, pipeline warning signs were installed during initial cleanup then permanently reinstalled after final cleanup.

No causal factors were found related to final cleanup and restoration activities even though environmental conditions may not have been ideal.

5.1.1.4 Damage Occurred During Operation (Eliminated)

The review of factors that could have led to damage during operation revealed that:

- No one-call events have been documented within 1.3 miles (2.1 km) of the failure location over the operational life of the pipeline.
- In witness statements, aerial patrol confirmed that they had not identified any unauthorized encroachments in this area since the pipeline was placed into operation in June 2010. Per regulatory requirements and TransCanada's operations and maintenance procedures, the area is patrolled 26 times per year.
- The land surrounding the release site is designated CRP land which is maintained in its natural state; no cultivation activities are performed in this location.
- No roads have been built or other utilities installed near Ludden +17 over the operational life of the pipeline.
- The ROW contains line-of-sight marking to notify the public and those working along the ROW of the existence of the buried, petroleum pipeline and a number to call in case of an emergency.
- No repairs or pipeline work had been conducted in the location of the failure since operations began.
- The mechanical damage at this location all occurred sometime after lowering the pipe into the trench and prior to the October 30, 2010 DCVG survey. The DCVG survey showed a 2% IR indication at the failure location which can be interpreted as indicating that the damage had occurred prior to the survey.

Since no construction activities (authorized or unauthorized) had occurred in the Ludden +17 area since operations began and the land is not cultivated, no causal factors were identified for damage occurring during operation.

5.1.2 Mechanical Damage Not Detected

The most likely timeframe in which pipe joint 857504 was damaged was during pipe installation construction activities. TransCanada implemented several construction quality safeguards to identify damage to the pipe and coating prior to placing the pipeline into operation as defined in the Keystone Pipeline Construction Quality Manual. Some of the specific quality processes that were implemented included visual inspections, regular audits during construction, coating holiday detection, a pre-service hydrostatic test, and a post-construction caliper survey. Moreover, TransCanada conducts regular high-resolution magnetic flux leakage (MFL) ILIs to identify injurious flaws in the pipeline, one of which was conducted in May 2016, as well as aboveground electrical surveys to find coating flaws that might be indicative of mechanical damage or other integrity concerns.

5.1.2.1 Damage Not Discovered During Pipe Installation Inspections (Causal Factor)

5.1.2.1.1 Damage Not Detected During NDE (Inconclusive)

The review of factors that could have led to the mechanical damage remaining undiscovered during pipe installation NDE indicated:

- Per the Lower-in Inspector's Daily Report final jeeping was conducted prior to lowering-in the pipe near the release location. Although documentation on the results of this inspection was not obtained, there was no indication that pipe damage or coating anomalies were found and there was no evidence that coating repairs were made at the location of the mechanical damage. Pipe jeeping records both before and after the area containing pipe joint 857504 were provided and did not indicate any major coating issues. The coating holiday created by the mechanical damage at Ludden +17 should have been easily detected with properly functioning equipment and properly trained inspectors.
- PHMSA audits were conducted at least twice per month during the construction of Spread 2A. During these audits PHMSA reported findings of crews not aware of new procedures for jeep voltages, jeeping crews traveling at rates exceeding 2 ft/s, unapproved materials being used to repair coating holidays, careless work crews damaging coating with timbers, workers not properly mixing epoxy coating repair materials, and the potential to sacrifice coating quality at girth welds to maintain application rate consistent with welding progress.

- There were also three coating related NCRs: (1) fiber board was found adhered to the pipe and then jeeped over during pre-jeeping operations (June 18, 2008); (2) 3M 323 two-part epoxy was not on the approved list but found being used to repair holidays during lowering-in (July 8, 2008); and (3) Royston Handy Cap cadweld coating system was not on the approved list but found being used (July 18, 2008).
- A post construction caliper survey was conducted in September 2009 between MP 218.5 and MP 259 in accordance with the conditions outlined in the Special Permit. The survey did not report denting or ovalities at the location of the release within the tool's reporting threshold of a 1% of OD for dents and 5% of OD for ovality.
- Mechanical damage without denting is not detectable with a caliper tool alone. High strength pipes with greater wall thicknesses are less likely to dent. The wall thickness for pipe joint 857504 was nominally 0.386 inch with average yield strength of 87.7 ksi, significantly stronger than its Grade specification of X70. Therefore, any denting that may have occurred during impact would likely be smaller and more challenging to detect using conventional caliper tools.

Holiday detectors, when functioning and operated properly, are capable of finding pinholes in the coating. It therefore is reasonable to expect that this inspection would have easily detected the large patch of missing coating on pipe joint 857504. However, because of a lack of documentation, the investigation team could not conclusively rule out that the coating damage was not present during holiday detection.

The investigation team believes that the mechanical damage found at Ludden +17 existed at the time of the caliper survey; however, as confirmed by the metallurgical analysis, there was no apparent denting of the pipe and therefore the caliper survey was eliminated as a causal factor.

5.1.2.1.2 Damage Not Detected Visually (Causal Factor)

The review of factors that could have led to the mechanical damage remaining undiscovered during visual inspections of the pipe during installation indicated:

- The only method for detecting damaged pipe once it was lowered-in to the trench was through visual examination from the working side of the ROW (west). For safety reasons, construction crews were prohibited from entering the trench after the pipe had been lowered.
- The procedures and associated forms that were used to document visual inspections for pipe or coating damage after lowering-in the pipe, during or after set-on weight installation, or during backfill activities at the time Spread 2A was constructed were lacking specific details on what to visually inspect and record. Other than an area for

'remarks' the forms did not contain details regarding visual observations that should have been made related to pipe or coating damage during these construction activities. A Damaged Pipe Report should have been completed if damage was found but no such document was attached to any of the daily inspection reports.

- Inspectors did receive training and on-boarding which covered what was expected of them to execute their jobs and maintain construction quality standards even if not specifically addressed on the inspection forms.
- Complicating matters were the wet, muddy conditions along the ROW and in the trench.
- Trenching, lowering-in, weight installation, and backfill crews were all working in sequence to install the pipe which elevated the risk of inadvertent pipe contact and the possibility that the damage would not be detected.
- As noted in the metallurgical report, the mechanical damage occurred between the 11:00 and 12:00 clock positions which would have been located on the east side of the construction ROW, opposite the working side. It is possible that the pipe was coated with mud making it difficult to visually detect that damage to the pipe had occurred on the opposite side of the trench.

Because of the difficult work environment during pipe lowering-in as well as inadequate procedures and forms to document visual pipe inspections during these activities, damage not being visually detected during installation was determined to be causal to this incident. Root causes include inspection procedures and processes were not adequately addressed in the SPAC as well as a PIO for inspection instructions and forms.

5.1.2.1.3 Damage Not Detected During Commissioning Hydrostatic Test (Eliminated)

The review of the commissioning hydrostatic testing documentation for Spread 2A-4 indicated:

- A pre-service hydrostatic test commenced on June 26, 2009 between MP 218.82 and MP 259.18.
- The hydrostatic test complied with CFR Title 49 Paragraph, Subpart E – Pressure Testing, §195.314, TransCanada Special Permit PHMSA-2006-26617, and Keystone Project Specification KPP-901.
- The test was an eight-hour combined strength and leak test with no pressure reduction separating the two parts. The minimum leak test pressure was [redacted] psig (100% of SMYS) and did not exceed 110% SMYS.

- The investigation team believes that the damage to pipe joint 857504 occurred sometime during lowering-in and weight installation. As such, the damage would have existed at the time the hydrostatic test was conducted.
- Based on the metallurgical examination, the deepest portion of the sliding contact marks was approximately 0.046 inch deep. Damage to the microstructure of the metal under mechanical damage can vary but is usually less than 10% of the pipe wall thickness. Initial cracking during either formation of the mechanical damage or re-rounding during pressurization usually occurs within this layer. An assumed crack as long as the observed region of gouges, 30 inches, and having an aggregate damage depth (scrape plus crushed microstructure) of 0.085 inch, and considering actual strength and toughness of the pipe, would have been expected to survive a hydrostatic test to 100% of SMYS.

Based on this analysis, the mechanical damage on pipe joint 857504 would not have failed at the hydrostatic test pressure and is therefore not causal to this incident.

5.1.2.2 Damage Not Discovered During ILI (Causal Factor)

The review of the Special Permit, high-resolution MFL documentation, and raw data for piggable segment KS6 indicated:

- Per the Special Permit, TransCanada was required to perform a baseline ILI using a high-resolution MFL tool capable of gouge detection within three years of placing the pipeline segment in service. This initial inspection was conducted September 2, 2012 using the [redacted] high-resolution MFL and caliper technology. A second inspection was conducted in May 2016 using the [redacted] MFL and caliper technology.
- Neither of these technologies detected external metal loss in excess of 10% WT or with an FPR less than 1.42 within 500 feet of the failure location. In addition, no metal loss or geometry features were identified at the failure location by either tool.
- The ILI technologies chosen for the integrity assessments were high-resolution MFL technology which primarily detects metal loss anomalies and caliper technology which is used to detect dents, among other geometry features. Most pipeline companies choose MFL and caliper tools for the first scheduled integrity assessment since corrosion and third party damage tend to be the highest risk threats for a pipeline and these tools can reliably withstand harsh operating conditions.
- The ability of an axially-oriented MFL tool to detect mechanical damage depends on the orientation and dimensions of the damage. The mechanical damage feature on pipe joint 857504 did not produce denting in the pipe of sufficient magnitude to be reported

by a caliper survey. Metal loss that is long in the axial direction (length) and narrow in the circumferential (width) direction is challenging for MFL tools to detect. The long (in aggregate) nature of the anomaly that failed is one possible reason that both the 2012 and 2016 MFL inspections did not report this anomaly.

- Another possible reason that the MFL ILI did not report this anomaly is that the construction equipment displaced metal on the surface of the pipe rather than removed it. In other words there was not net metal loss. It appears that the equipment plowed a series of furrows with decreased wall thickness followed by ridges of increased wall thickness. If the furrows and ridges were nominally aligned with the flux direction, then the ridges can carry the flux displaced by the furrows and the effective metal loss signal would be negligible for a traditional MFL tool.

Even though multiple ILIs were conducted along Spread 2A, the types of tools used by TransCanada and required by the Special Permit were not capable of finding the mechanical damage or cracking that occurred on pipe joint 857504. If other tools such as CMFL or low-field MFL were run, they may have detected the mechanical damage or associated cold work. Alternatively if an UTCD tool were run it likely would have detected the subsequent fatigue cracking. Not recognizing the potential hazard for fatigue crack growth in mechanical damage that does not exhibit appreciable denting and not implementing ILI tools to address this threat was determined to be causal to this incident. There is a PIO for TransCanada to enhance their IMP to baseline newly constructed pipelines with ILI tools capable of detecting flaws that do not exhibit appreciable metal loss or denting. Recognizing this gap, TransCanada chose to run [redacted] tool subsequent to the failure to find axial cracking at other locations along Spread 2A. Additionally, TDW's multi-data set (MDS) tool was run in KS6 (spanning the majority of spread 2A) to determine if additional mechanical damage, that may give rise to cracking in the future, was present.

5.1.2.3 Damage Not Discovered During Aboveground Surveys (Eliminated)

5.1.2.3.1 Damage Not Detected During DCVG Survey (Confirmed, but not Causal)

The review of DCVG documentation for Spread 2A indicated:

- A DCVG survey was conducted October 30, 2010 to identify coating faults.
- The voltage gradient is described in terms of %IR which provides a relative ranking of the seriousness of a coating defect. TransCanada specifies that values greater than 35% IR require immediate action, values between 16% and 35% IR require monitoring, and values less than 15% IR are considered minor coating faults that do not require repair, which aligns with industry practice. TransCanada has also implemented a more

stringent requirement where a 10% IR or greater indication coinciding with a top side dent would require immediate action.

- At the location of the failure, the DCVG survey noted a 2% IR indication. The size of this indication was not actionable according to either criterion, even if denting was reported by the caliper survey, which it was not.
- DCVG indications can be affected by factors such as the shape and orientation of the coating defect, surface films on exposed steel, local variations in soil resistivity, and depth of the defect.
- The set-on, concrete weights presented an area of locally high resistivity which may have suppressed the %IR signal during a DCVG survey.
- Burial depth could have also reduced the %IR signal. Per the Special Permit, Keystone was required to have a DOC of four feet as opposed to the more common 49 CFR 195 regulatory requirement of three feet. At the location of the failure, the pipeline was actually at a burial depth of approximately six feet so that the DOC over the set-on concrete weights achieved four feet. The %IR reading at six foot depth could potentially be half of the %IR reading at a three foot depth.

The combined effect of higher local resistivity from the concrete weights and a six-foot burial depth could have reduced the DCVG %IR reading making the coating fault appear to be less significant than what was actually discovered. The exact impact is unknown and may still have been below the reporting thresholds. Therefore DCVG not indicating an actionable coating fault was eliminated as a causal factor. As an item of note TransCanada should consider the impact of burial depth and local areas of high resistivity on DCVG results.

5.1.2.3.2 Damage Not Detected During CIS Survey (Confirmed, but not Causal)

The review of CIS documentation for Spread 2A indicated:

- As required by the Special Permit, an initial CIS was conducted October 30, 2010 and integrated with the baseline ILI data to determine whether any action was required to mitigate external corrosion along Keystone Phase 1.
- The lowest CP OFF potential measured within 500 feet of the release location was -1,114 mV which exceeded the minimum instant-off criterion of -850 mV per NACE SP 0169.
- Neither the 2012 nor 2016 ILI identified metal loss in excess of 10% WT in depth, or with a FPR less than 1.42 within 500 feet of the release location.

- Even though the set-on concrete weights can act as a localized area of high resistivity potentially shielding CP, the results of both the CIS and ILI show that corrosion was not a concern at the failure location. This was also confirmed by the metallurgical analysis which did not find any evidence of external corrosion within the mechanical damage area.

The CIS results integrated with the ILIs and metallurgical analysis confirmed that CP was protecting the pipe at the failure location and therefore was eliminated as a causal factor.

5.1.2.3.3 Damage Not Detected During CP Test Station Surveys (Confirmed, but not Causal)

The review of CP test station survey documentation for Spread 2A indicated:

- TransCanada has been conducting annual CP surveys in accordance with Federal regulations since initial operation.
- The CP OFF potentials at the test leads closest to the failure location (0.67 mile upstream and 1.39 miles downstream) have consistently exceeded the NACE SP 0169 criterion of -850 mV OFF potential.

The CP surveys not indicating a problem with corrosion protection at the location of the mechanical damage feature was found not to be causal to this incident.

5.1.3 Mechanical Damage Grew to Failure

As shown in the metallurgical analysis, multiple cracks developed in the mechanical damage one of which grew to failure on November 16, 2017. Several possible sequences of causes and effects were postulated to have contributed to the crack growth and failure during operation including (1) pressure cycling, (2) high pressure event, (3) temperature cycling, or (4) other external conditions.

5.1.3.1 Pressure Cycling (Confirmed, but not Causal)

The review of operational data between Ludden and Ferney indicated:

- The Special Permit required an annual fatigue analysis to determine the pipe reassessment interval for the first five years of operation; however, this analysis only pertained to manufacturing flaw from seam welds and did not consider cracks that may have formed in mechanical damage.
- Using conservative assumptions, the theoretical minimum fatigue life of a seam flaw along Keystone Phase 1 was 35 years. The 35-year fatigue life is not applicable to the mechanical damage found at Ludden +17.

- Even though the Ludden to Ferney segment is not the most aggressively cycled portion of Keystone Phase 1, the mechanical damage that occurred initiated a crack of sufficient size to grow to failure by pressure-cycle induced fatigue in less than eight years of operation. The time to failure is a function of flaw size and frequency and magnitude of pressure cycles.

Because the caliper tool surveys did not indicate any denting and the 2012 and 2016 high resolution MFL tool runs did not show any metal loss indicative of mechanical damage, fatigue crack growth in mechanical damage was not considered as a significant threat to the integrity of the Keystone Phase 1 pipeline. As such, there were no requirements in the IMP to run a crack detection tool, CMFL, or low-field MFL tool to detect cold working or cracking related to mechanical damage. Pressure cycling contributed to the failure but was not sufficiently fundamental to be a root cause.

5.1.3.2 High Pressure Event (Confirmed, but not Causal)

The review of operational data between Ludden and Ferney indicated:

- The discharge pressure at the Ludden Pump Station was operating near the MOP of 1,440 psig (0.80 design factor) from February 2017 through August of 2017. [redacted]
- A review of the Ludden Pump Station discharge pressure data leading up to and at the time of the release does not indicate any overpressure events or inadvertent valve closures which could have led to an overpressure at the location of this release.
- At the time of the incident, the Ferney Pump Station was in by-pass mode to allow passage of a cleaning pig and SmartBall® leak detection tool. The increase in the discharge pressure when the downstream pump station is in by-pass mode is a normal operating condition during ILI and the pressures did not exceed the MOP.
- Though the pressure was increasing at the time of the incident, the pressure did not increase beyond the MOP. The fatigue crack had grown large enough to rupture at the operating pressure of approximately 1,350 psig, based on using API 579 Failure Assessment Diagram, Level 2 analysis accounting for actual material properties.

Because Keystone was operating as expected during the cleaning tool run and SmartBall® inspection, a high pressure event contributed to the failure but was not sufficiently fundamental to be a root cause.

5.1.3.3 Temperature Cycling (Eliminated)

The review of operational data between Ludden and Ferney indicated:

- Keystone Phase 1 is restricted to a maximum operating temperature of 150°F by the Special Permit. The operating temperatures have been maintained below this requirement for the operational life of the pipeline.
- The operating temperature for Keystone Phase 1 varies seasonally and has demonstrated an increasing trend over time which can be tied to the increases in operating pressures and flowrates.
- ASME B31.4 and other pipeline design codes and standards require no derating of line pipe strength at 150°F.

Fatigue crack growth rates are not known to increase with increasing temperature in the range of interest. In fact they have been demonstrated to decrease slightly at temperatures above room temperature, possibly due to dynamic strain-aging effects. Thus operating temperatures are not considered to be a contributing factor.

5.1.3.4 Other External Events (Eliminated)

The review of the metallurgical analysis, ILI documentation, and site specific documentation indicated:

- Any effects from a step change in stress due to external loads would have been seen as ductile tearing on the fracture surface beyond the original crack. These features were not seen in the metallurgical examination and therefore crack extension due to a change in stress did not contribute to this incident.
- The site is not known to be susceptible to geotechnical hazards and land usage at the site is not associated with heavy or frequent external loads from vehicles or equipment crossing the pipeline.
- The metallurgical analysis did not find any evidence of corrosion products in the sliding contact marks or cracks. This was confirmed by the 2012 and 2016 ILI runs as well as the CP test station surveys and CIS showing that the pipeline was adequately protected by CP in the Ludden +17 area.

The evidence did not indicate that geotechnical hazards, corrosion growth, SCC growth, or other external factors could have contributed to the failure and therefore were eliminated as potential factors.

5.1.4 Volume of Crude Oil Released

Several components of Keystone's LDS and response were examined to determine whether their performance contributed to the volume of the release. The investigation determined that the LDS, OCC, and response team exceeded expectations and were able to shut down the pipeline within three minutes of the first indication of the rupture and isolated the pipeline within 12 minutes of the first indication. Prompt notifications were made to the Regional and Corporate EOCs as well as the NRC and PHMSA once the spill location was confirmed.

5.1.4.1 Leak Not Discovered by Internal Leak Inspection (Eliminated)

Witness statements and documents related to the SmartBall® inspection indicated:

- TransCanada has run the SmartBall® leak detection tool every year since 2015.
- At the time of the Ludden +17 incident, the 2017 SmartBall® run was being conducted and had passed the failure location approximately four hours prior to the rupture on its way to the Ferney Pump Station. The data was reviewed from the November 15, 2017 run and there was no indication of a leak at the failure location.
- The SmartBall® leak detection technology is stated to have a leak detection threshold of 0.03 gal/min (110 mL/min) which is one of the lowest detection thresholds for pipeline leaks in a non-real time tool.
- A potential leak rate was estimated assuming a 1.95 inch long crack (the length of the crack at the ID as discussed in the metallurgical analysis) with a width of 0.01 inch and crude oil specific gravity of 0.8. The estimated leak rate was calculated to be 7.1 gal/min (2.7×10^4 mL/min); more than two hundred times larger than the SmartBall® detection threshold.

Based on this analysis, the investigation team concluded that the fatigue crack was not leaking at the time the SmartBall® inspected this location or else it would have been detected and therefore is not causal to the release volume.

5.1.4.2 Leak Not Discovered by Aerial Patrols (Eliminated)

Witness statements and procedures related to the aerial patrols indicated:

- TransCanada conducts an aerial patrol (low level flight) on all sections of the Keystone pipeline ROW every two weeks (nominally 26 times per year) to visually inspect the ROW, identify any work occurring on the ROW that is not approved or places where the pipeline has not been located, and for identification of potential indications of a release.
- All pilots flying the TransCanada ROW are Operator Qualified, as per regulations, to perform the task of Aerial Patrol. The re-qualification is completed every three years.

- Records from the November 3, 2017 patrol were reviewed and confirmed that there were no indications of leaks, third party activity, or other anomalous conditions in the location of the release.

The SmartBall® inspection also confirmed that the damage did not leak prior to rupture and therefore aerial patrols were eliminated as causal to the release volume.

5.1.4.3 Leak Detection System Response Issues (Eliminated)

Witness statements, procedures, and control room response documents indicated:

- TransCanada uses a real-time transient model (RTTM) as the primary leak detection method, which is a sophisticated compensated mass balance system and reflects industry best practice.
- Witness interviews indicated that all devices within the affected segment were in working order at the time of the release. All transmitters (pressure, temperature, and flow) were checked for false alarms in the segment of concern and no false alarms had occurred.
- TransCanada conducts performance testing of the LDS at least once per year, using either a full transient model to simulate leaks of various sizes or through physical withdrawal to measure LDS performance. According to witness statements the LDS has always met the performance requirements during testing as evidenced by the test completed in May 2017.
- Flowing and shut-in thresholds were at levels that met or exceeded the leak detection performance requirements and API RP 1149.
- A review of pipeline shut-ins was performed to determine if the affected segment could have leaked prior to the rupture on November 16, 2017. There were no changes in pressure decay that might have been indicative of a leak.
- A review of pressure and flow trends during flowing and shut-in conditions, SCADA events and alarms, and LDS events in the affected segment from the time of the incident back until June 2017 did not reveal any indications of a leak prior to the rupture at 5:33 AM central time on November 16, 2017.
- The Keystone LDS alarmed indicating an immediate loss of line pack and flow at 5:34 AM central time, only one minute after the pressure drop was noted at [redacted].

The LDS alarmed as designed when it detected a maximum leak flowrate of [redacted] m^3/hr, exceeding the [redacted] m^3/hr threshold over a two-minute averaging window, and therefore was eliminated as a potential causal factor to the release volume.

5.1.4.4 Control Room Response Issues (Eliminated)

Witness statements, procedures, and control room response documents indicated:

- TransCanada dedicated a controller on each shift to exclusively monitor the LDS. All TransCanada controllers have the authority to shut down the pipeline in accordance with safe shutdown procedures if a leak is suspected or if an abnormal condition cannot be explained.
- On the day of the incident, all processes worked as planned and the available data was reliable. Controller actions during this event followed all procedures and occurred in a timely manner such as to limit the impact of this event.
- On November 16, 2017, at 5:33 AM central time, the Keystone SCADA system detected a pressure drop at [redacted]. At 5:34 AM a low suction alarm and Unit A2 SDR ALM sounded followed by an LDS alarm between Ludden and Carpenter indicating a 2-minute flow of [redacted] m^3/hr and peak flow of [redacted] m^3/hr.
- Within 44 seconds of receiving the leak alarm, the controller began to shut down the pumps at Hardisty and Lakes End. Twelve minutes after the controller began shut down operations, the mainline valves sectionalizing the affected segment were closed and the line was isolated.

No delays in responses were found whether from initial notification to shutdown; shutdown to isolation; isolation to notification of field technicians; or in initiation of the EOC. Even though the event occurred toward the end of the night shift, when fatigue would have been at its highest, the control room performance exceeded expectations. For these reasons the control room response was eliminated as a causal factor to the spill size.

5.1.4.5 Emergency Response Issues (Eliminated)

The emergency response was managed by TransCanada personnel and contractors, with security and logistical support provided by local law enforcement, fire service, and emergency management. TransCanada is currently performing an internal review of the emergency response which will be presented to PHMSA in a separate document.

5.1.5 Applicability of Findings and Lessons Learned to Other Locations

The findings and lessons learned from this incident are potentially applicable to other locations along the Keystone pipeline where set-on, concrete weights were installed during adverse environmental conditions along the ROW. The work currently being performed by TransCanada as part of their remedial work plan (RWP) is effectively addressing the findings of TransCanada's own review of the incident and of this study and their applicability to other locations along Spread 2A.

5.2 Recommendations

A number of recommendations and opportunities for improvement are proposed as a result of this RCFA and are discussed below.

5.2.1 Causal Factors

5.2.1.1 Pipe Damage Occurred During Pipe Installation

- During the design phase, the engineering team should investigate the value of obtaining site specific soils data to better anticipate the need for buoyancy control should adverse environmental conditions be experienced during construction.
- For changes in pipeline depth that are made in the field (e.g. addition of buoyancy control and side digging), the associated risks of the change should be adequately documented and the effect of the change on subsequent construction, operation, maintenance, and integrity activities should be evaluated. Consider providing additional guidance and procedures for workers in the field when encountering these specific situations.
- The impact that adverse environmental conditions can have on trenching, lowering-in, and backfill construction activities should be more broadly considered in pipeline construction specifications as well as on the inspection forms. Provisions for additional damage prevention or mitigation measures (e.g. additional inspections) should be considered under such circumstances.

5.2.1.2 Damage Not Detected Visually

- Provisions for additional damage prevention or mitigation measures (e.g. additional inspections or aboveground surveys) should be considered when changes are made in the field to accommodate conditions found along the ROW or when the ROW conditions are such that the risk for pipe damage from construction equipment is elevated.
- Update inspection forms to specifically address the inspector's responsibilities as outlined in the construction quality manual, including data fields for required measurements. Consider using electronic database platforms to record inspection findings so that information can be viewed in real time and integrated with other datasets.
- Consider placing inspectors on both sides of the ROW to visually inspect for damage.

5.2.1.3 Damage Not Discovered During ILI

- Develop a risk-based strategy for post-construction integrity assessments using additional technologies capable of detecting cracking or cold working that can be associated with mechanical damage. Approaches can include circumferential MFL (CMFL), spiral MFL (SMFL), low-field MFL, ultrasonic crack detection (UTCD), or additional technologies capable of detecting cold working or cracking. In absence of being able to detect the initiating mechanical damage feature, periodic crack detection should be considered.

- Consider implementing a post-construction ILI using CMFL or low-field MFL technology to detect cold working associated with mechanical damage.
- Update IMP procedures to reflect the threat of cracking in mechanical damage without appreciable denting and the new inspection strategy to identify such threats.

5.2.2 Potential Improvement Opportunities

5.2.2.1 Damage Not Detected During Final Jeeping

- Improve final jeeping inspection forms to better reflect the results of the inspection as well as documenting daily calibrations, voltages, travel speeds, and repairs. Consider using electronic database platforms to record inspection findings so that information can be viewed in real time and integrated with other datasets.

5.2.2.2 Damage Not Detected During DCVG

- Consider the impact of burial depth and local areas of high resistivity on aboveground survey results. If necessary, consider implementation of alternative technologies to overcome limitations.

6 REFERENCES

Many documents and photographs were provided by TransCanada for review during the investigation that included project management, construction records, project specifications, welding procedures and forms, welder qualifications, finite element analyses, hydrostatic testing, alignment sheets, inspection reports, NDE procedures and forms, PHMSA audits, CP system data, engineering assessments, metallurgical analyses, integrity verification plan activities, geotechnical reports, ILI data, oil control and system operations plans and procedures, operator qualifications, pipeline integrity data, failure investigations, field operations, leak detection, emergency response plans, aerial patrols, weather data, and safety procedures. The references provided below were directly used in development of this RCFA report.

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7 APPENDIX A – PIPELINE SYSTEM ALIGNMENT MAP

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