DOT	U.S. Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety's Accident Investigation Division

Principal Investigator	Brian E. Pierzina
AID Director	Peter Katchmar
Date of Report	November 28, 2018
Subject	Failure Investigation Report: Material Failure – Mechanical Damage from Original Construction – TC Oil Pipeline Operations, Inc.

Operator, Location, & Consequences

Date of Failure	11/16/2017
Commodity Released	Crude Oil
City/County & State	Amherst/Marshall – South Dakota
OpID & Operator Name	32334 – TC Oil Pipeline Operations, Inc.
Unit # & Unit Name	72676 – Keystone Mainline #1 (MP 0.00 to MP 310.70)
SMART Activity #	158348
Milepost/Location	MP 234.2 – Ludden + 17[1]
Type of Failure	Rupture – Material Failure – Damage from Original Construction
Fatalities	0
Injuries	0
Description of area impacted	Bermed conservation reserve program (CRP) field – Agricultural Area – Non-HCA
Total Costs	$44,809,560

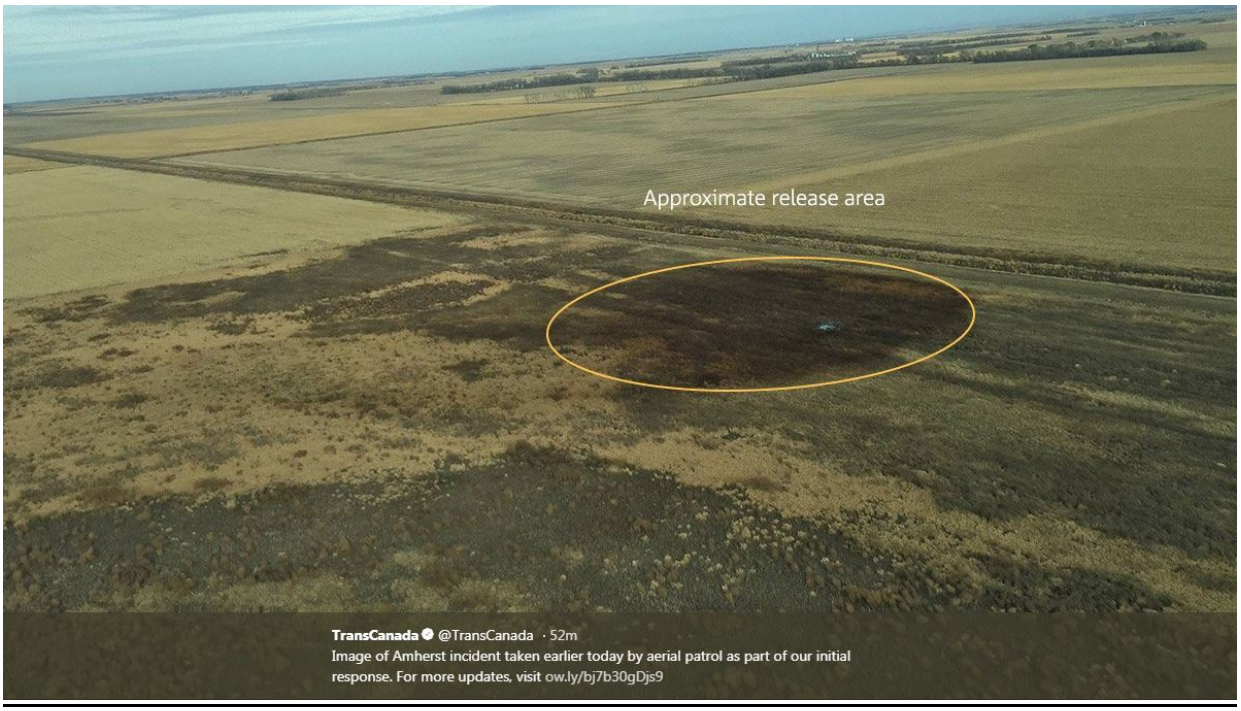
[1] TransCanada commonly refers to locations along the pipeline by referencing a nearby pump station and a distance in miles from that station. Ludden + 17 refers to a location 17 miles downstream from the Ludden pump station in North Dakota.

Executive Summary

On November 16, 2017, at approximately 05:33 Central Standard Time,[2] TC Oil Pipeline Operations, Inc. (TransCanada) 30-inch diameter crude oil pipeline (Keystone) ruptured near Amherst, SD. The rupture resulted in an estimated release of 6592 barrels of crude oil. The estimated spill volume is significantly less than a worst-case discharge scenario due to rapid detection of and control center response to the rupture, coupled with a failure location near the top of the pipe.

The failure has been determined by metallurgical evaluation to be the result of mechanical damage that was sustained during original construction of the pipeline. The gouges in the pipeline associated with the failure were found to have elevated levels of chromium, compared to the parent material. The most probable contributor of chromium would be the cleats of tracked heavy equipment that was used extensively throughout the construction process. The specific circumstances resulting in creation of the failure defect were unreported at the time it was sustained. The failure defect was undetected by numerous on-site inspections during construction, post-construction hydrostatic testing, and multiple integrity/quality assurance assessments. It grew incrementally in service (approximately 7.4-years) until failure. In response to the accident, PHMSA issued a Corrective Action Order (CAO) to TransCanada.[3] The CAO contained several requirements associated with investigation, repair, restart, and integrity verification of the pipeline.

[2] All times are Central Standard Time unless otherwise noted.
[3] PHMSA. (November 28, 2017). CPF #3-2017-5008H. Washington, D.C. Retrieved from: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/56511/320175008h-corrective-action-order-transcanada-11282017.pdf.

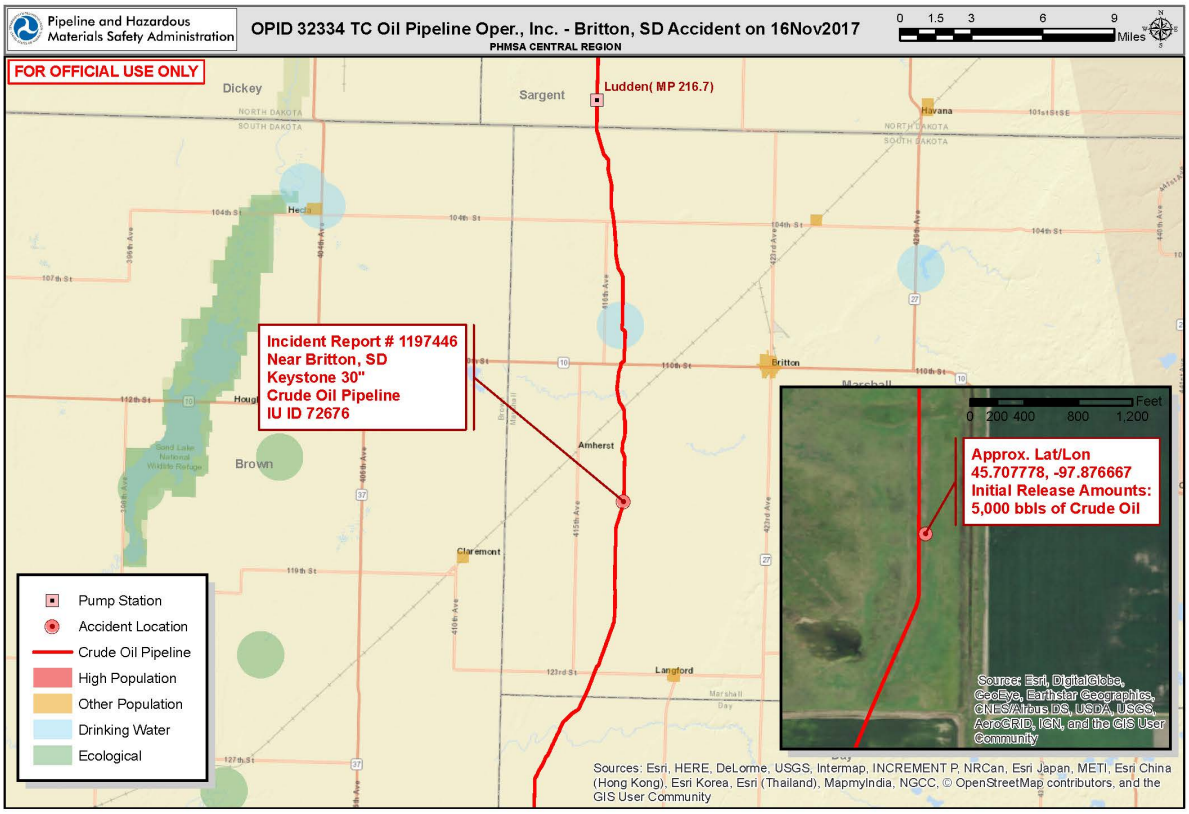


System Details

The Keystone Pipeline originates in Hardisty, Alberta, Canada and delivers crude oil to terminals in Patoka, IL and Cushing, OK. The U.S. portion of the pipeline is 1084 miles long, and has 23 pump stations along the route from North Dakota, South Dakota, Nebraska, Kansas, Missouri, Illinois, and Oklahoma. The rupture occurred downstream of the Ludden (ND) pump station, at MP 234.2, in Marshall County, SD. The accident site was in a field, and did not impact a high consequence area (HCA). The section of pipe that failed was constructed in the fall of 2008, as part of construction spread 2A. The failure pipe is 30-inch diameter, 0.386-inch wall thickness, grade X-70 – manufactured by Berg, with a double submerged arc-welded (DSAW) longitudinal weld seam. Concrete set-on weights were installed in the area of the failure to provide negative buoyancy, and maintain the depth of cover.[4] The pipeline was constructed, and is operated under a PHMSA Special Permit (SP),[5] which allows operation at up to 80% of specified minimum yield strength (SMYS). The maximum operating pressure (MOP) of the pipeline has been established as 1440 psig.

[4] Weights are placed on the top of the pipe in wet areas to keep the pipe from floating.
[5] The U.S. Department of Transportation. (November 17, 2006). *Special Permit*. (Docket Number: PHMSA-2006-26617). Retrieved from: https://puc.sd.gov/commission/dockets/hydrocarbonpipeline/2007/Hp07-001/hearingexhibit/tc/tc11.pdf.

The SP allowed TransCanada to design, construct and operate two new oil pipelines (Keystone Mainline and Keystone Cushing Extension) using a design factor and operating stress level of



80% of the pipe's SMYS, subject to specified exclusions and 51 specific conditions. Design factors and operating stress levels were otherwise limited to a maximum of 72% of SMYS by regulation.

Construction Quality was specifically addressed by SP Condition #21. It required maintenance of a construction quality assurance plan throughout the construction phase of the pipeline. SP Condition #42 addressed Initial In-Line Inspection (ILI), and required a baseline ILI using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. The SP required the high resolution MFL tool to be capable of gouge detection. It also required the operator to perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than six-months after placing the pipeline in service. Additional conditions addressed future ILI inspections, fatigue analysis, crack detection, and reassessment intervals.

Events Leading up to the Failure

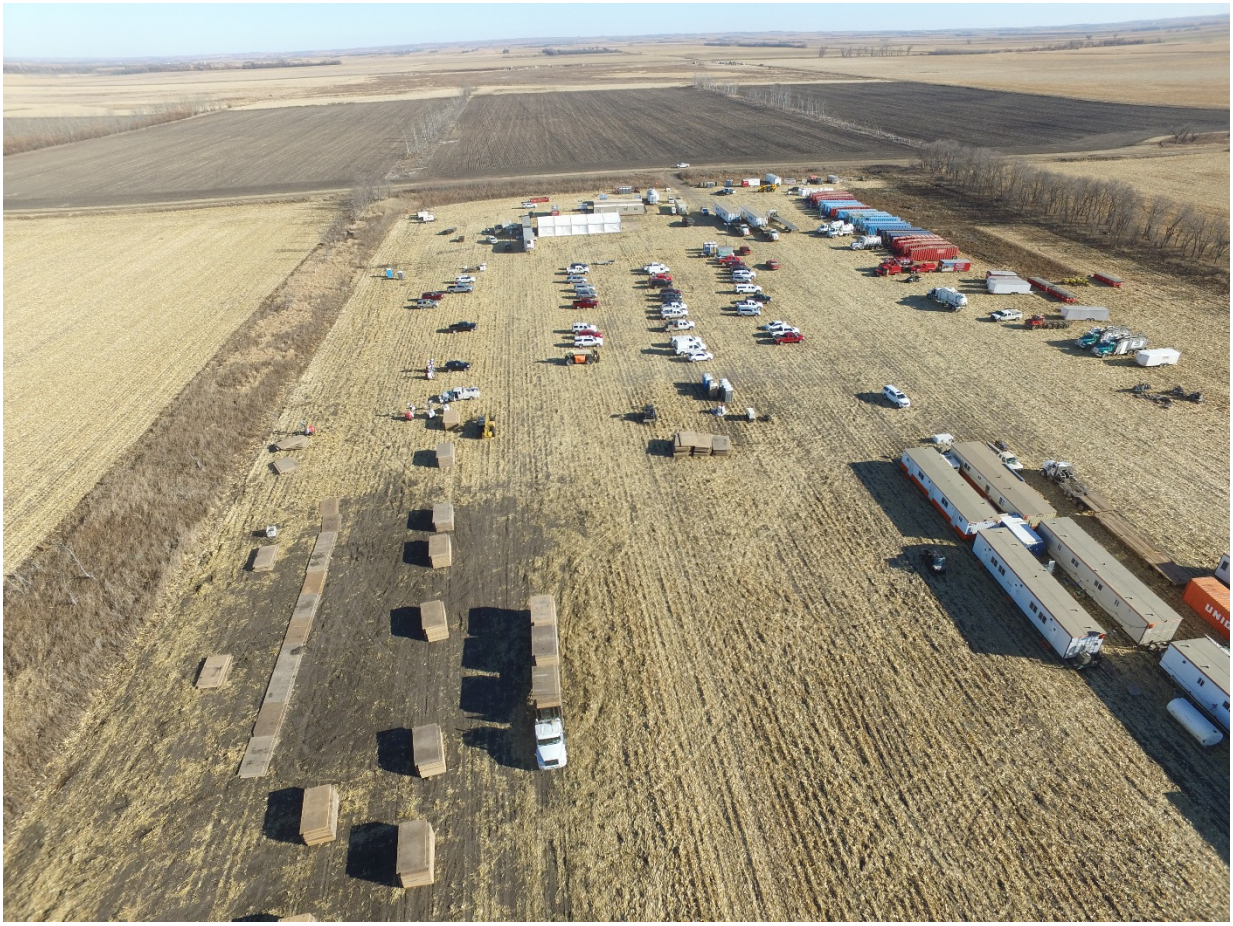
An ILI consisting of a cleaning tool ahead of a leak detection tool was being conducted in the area of the rupture at the time of the failure. Both the cleaning tool and the leak detection tool had travelled past the nearest block valve downstream of the rupture location (Ludden + 28) prior to the failure. The tools were run in a light-sweet blend (LSB) batch of crude oil, followed by a batch of sour crude. In preparation for the tools to bypass the next downstream pump station (Ferney, SD), a bypass operation of the Ferney pump station had been initiated at 05:03. The bypass of the Ferney pump station was fully executed at 05:24. The Ferney bypass resulted in a gradual and anticipated pressure increase at the Ludden discharge. The pressure records from Ludden indicate the pressure had increased from approximately 1170 psig to 1352 psig, when the rupture occurred.

Emergency Response

Pressure records show the first indications of the rupture were at 05:33, when a pressure drop was detected at the Main Line Valve (MLV) Ludden + 23.8. This was followed by an abrupt drop in discharge pressure and a corresponding dramatic increase in flow rate at the Ludden pump station. A pressure drop was observed at the Ferney pump station at the same time. The Controller at Keystone's Operational Control Center (OCC), in Calgary, AB initiated an emergency shutdown of the pipeline at 05:36, and commenced isolation and sectionalization of the pipeline. By 05:45 the failure location had been sectionalized using remotely operated valves. Personnel were dispatched to investigate the pipeline right-of-way for signs of a release, and confirmed oil on the ground at approximately 09:15. Marshall County 911 was contacted, and the Britton Fire Department and Marshall County Sheriff responded within minutes of notification. A safe perimeter of approximately 1 mile in each direction was established, and this security perimeter was maintained throughout the response. TransCanada provided its initial notification of the release to the National Response Center (NRC) at 10:17, almost 5 hours after the rupture occurred.[6] PHMSA immediately launched an on-site investigation utilizing personnel from the Accident Investigation Division, Central Region, Emergency Support Division, Community Liaison Group, and Executive Leadership.

[6] NRC. (November 16, 2017). *Report #1197446*. Retrieved from: http://nrc.uscg.mil/FOIAFiles/CY17.xlsx.

TransCanada response resources including safety, environmental, repair, integrity, and incident command were mobilized immediately. Incident Command and related response operations grew daily, to a maximum of over 200 individuals including company and contract personnel,



Overview of the man camp (lower right) and response equipment staging area.

and local, state, and federal agencies. An on-site camp capable of housing 90 people was established associated with the incident command location, to reduce the amount of commuting required to and from the failure site.

The failure location is in an area of very subtle elevation changes, which necessitated installation of stopple fittings upstream and downstream of the failure, in order to minimize the amount of pipe necessary to be drained to allow for replacement of the failed piping.[7] Both stopple fittings were in place, with plugs set, by November 25, 2017.

[7] Stopple – The installation of a flow-blocking device in a piping system that cannot otherwise be isolated.

As of July 24, 2018, TransCanada reported that all released product has been recovered, either as free-product, or within contaminated soil that has been removed from the site. Restoration of the accident site has been completed in accordance with applicable environmental standards.

Summary of Return-to-Service

A proposed restart plan for the pipeline was developed by TransCanada and approved by the PHMSA Central Region Director. The plan required a daylight restart, and a pressure restriction of 80% of the 60-day high pressure at the location of the failure. The 60-day maximum pressure at the failure location was determined to be 1175 psig. To ensure the pressure at the failure location did not exceed 940 psig, the maximum discharge pressure at the Ludden pump station was reduced to 1046 psig. A temporary MOP reduction from 1440 psig to 1152 psig was established for other locations along the pipeline associated with construction spread 2A, or similar wall thickness and manufacturer at the failure location.

Specific start-up procedures were established for the introduction of product into the pipeline necessary to reconstitute the column and re-pack the pipeline.[8] Estimates for the amount of time it would take to see a pressure increase at the downstream pump station were prepared for each section of the pipeline in order to ensure the line was packing as expected. This process took almost two days to complete. Advanced notice of the restart was provided to local emergency officials and landowners. Field personnel were deployed to all above ground facilities to check for leaks and confirm normal operations. Aerial patrols were also conducted over the de-rated section of the pipeline for three days to ensure any abnormalities could be recognized and addressed. The pipeline was restarted on November 29, 2017, at 10:00.

Investigation Details

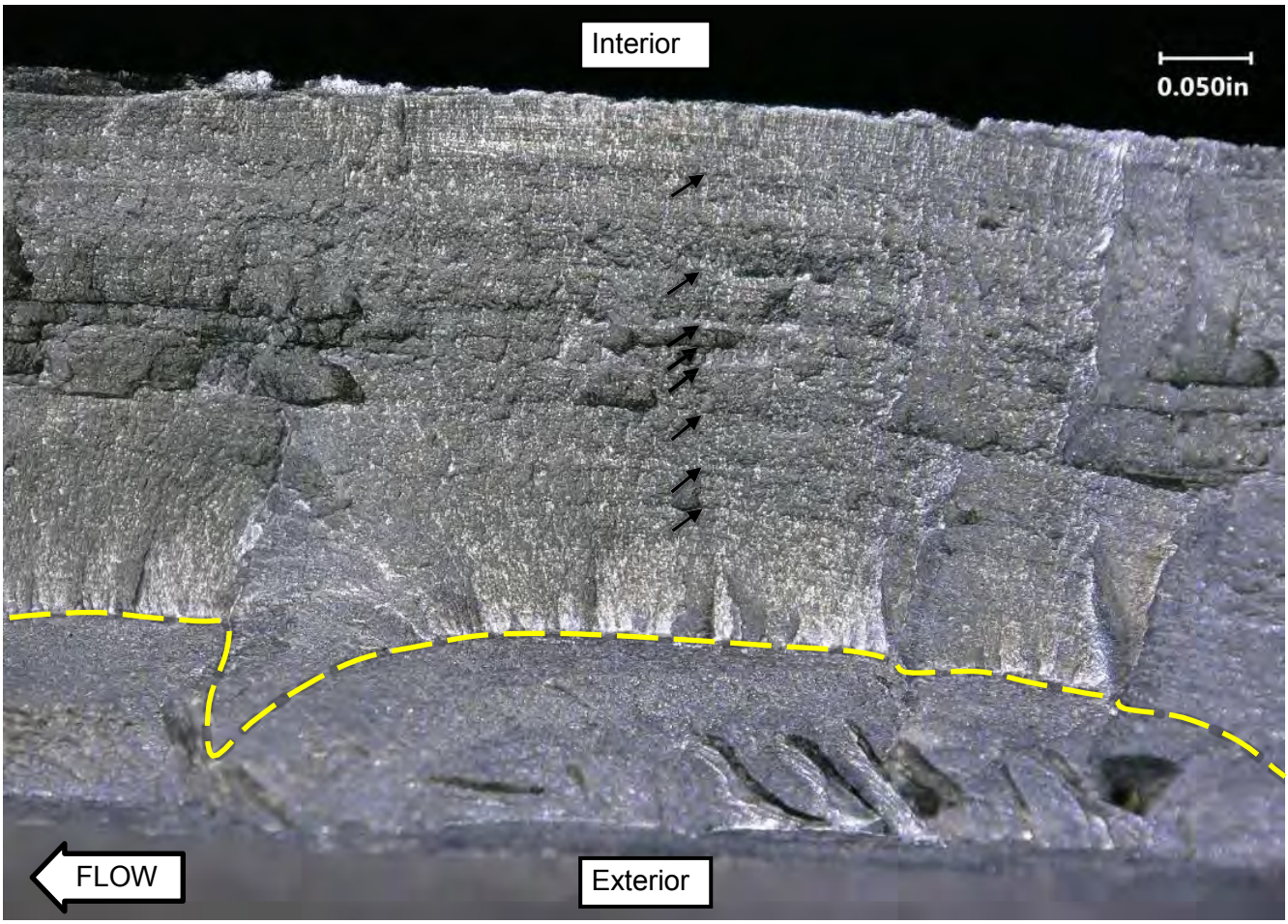
Initial observations of the failed pipe in the field were indicative of mechanical damage that had been inflicted to the pipe body. The damage was separate and apart from the longitudinal weld seam. The rupture origin did not involve a girth weld, but the rupture opening did pass through the adjacent girth weld. There was a set-on concrete weight in close proximity to, but not associated with, the rupture opening. The fracture surfaces were protected, and the failed pipe section was removed. The failed piping was prepared for shipment to the NTSB laboratory in Washington, DC.

Examination of the failed piping at the NTSB laboratory indicated the rupture was oriented in the axial direction, and extended to a length of 4 feet 4 inches. The rupture opening was just over 11-inches wide at its widest point. The rupture origin was approximately 5.5-inches long, perpendicular to the pipe wall, and exhibited characteristics consistent with fatigue growth.

[8] Reconstitute the column – While the pipeline is shutdown, low pressure creates vapor spaces and allows product batches to co-mingle. The pipeline is re-packed to mitigate these conditions.

Copied from the NTSB Metallurgical report: Figure 13. Overall view of the exterior surface after sectioning with the two sides of the fracture placed in close proximity. Dashed lines indicate the 12 o'clock position, and unlabeled brackets indicate the fatigue crack region.

There were indications of mostly axial and parallel gouges similar to sliding contact marks on both sides of the rupture opening. Some of these gouges were up to 30-inches long. Within the rupture origin fatigue region, the near-surface depth associated with the initial damage was 0.098 inches. The fracture surface exhibited eight somewhat distinct crack arrest and re-initiation lines at depths of 0.166-inches, 0.189 inches, 0.222 inches, 0.246-inches, 0.257-inches, 0.267-inches, 0.300-inches, and 0.340-inches. These features typically are associated with large pressure cycles, such as the post-construction hydrostatic test, or operational shutdowns.



Copied from the NTSB Metallurgical report: Figure 23. Optical image of the fatigue region at origin area A (see figure 21). Fatigue features emanated from near-surface cracks shown bounded by a yellow dashed line. Unlabeled arrows indicate relatively prominent crack arrest lines where emerging radial marks consistent with crack reinitiation were associated with the arrest line.

TransCanada initiated a Root Cause Failure Analysis (RCFA) for this accident, in accordance with the CAO. The RCFA was facilitated by an independent consultant and included a team of subject matter experts (SMEs) from TransCanada. The scope of the RCFA was to assess details associated with design, construction, operations, maintenance, integrity management, leak detection, and metallurgical analysis, and to formulate conclusions and recommendations associated with the findings. This included interviews, review of documents and records, and related analysis, in an attempt to identify potential causal and contributing factors to the failure.

The available evidence suggests the mechanical damage to the pipeline occurred during installation, most likely during trenching, lowering-in, installation of the set-on weights, backfilling, or rough cleanup. The bulk of these activities occurred November 7-8, 2008. The

inspection records associated with these activities indicate the location was wet and muddy,

Right-of-way conditions during construction on a similar but different spread.

the weather was cold and windy, and working conditions were very difficult. The available inspection records did not document an instance of equipment falling or sliding into the trench. The top of the pipe is approximately 6-feet below ground level. If the damage occurred after the pipe was lowered-in (as suspected), the actual event would have resulted in some relatively intense moments involving equipment operation. The RCFA Team did not interview contractor or inspection personnel who were on site during these activities.[9] The failure to detect, discover, or report the damage during installation and visual inspection of the construction operations was determined to be a causal factor to the accident.

[9] The construction occurred in the fall of 2008, nine years prior to the failure. Construction documentation was reviewed in detail, but the RCFA Team considered it too onerous to attempt to find and interview the actual workers involved.

Right-of-way conditions during construction on a similar but different spread.

The post-construction hydrostatic pressure test for the failure segment was completed on June 27, 2009. The test pressure did not fall below 101.7% of SMYS or exceed 107% of SMYS. The pressure test established the MOP for the pipeline as 1440 psig. A construction caliper ILI was performed through the pipeline segment containing the failure location on September 2-3, 2009. The grading specifications for this survey were 1% for dents, and 5% for ovality. There were no actionable anomalies reported associated with the failure location. A different caliper tool was run in 2010, but did not identify any geometry features associated with the rupture location.

After the pipeline was placed into service (June 30, 2010), above ground surveys were performed over the pipeline, including a Direct Current Voltage Gradient (DCVG) survey. DCVG surveys are used to identify coating faults on a pipeline by detecting relative changes in the flow of cathodic protection current through measurement of the voltage gradient (IR). In general terms, the larger the gradient, the larger the coating fault would be expected. TransCanada procedures required immediate action for IR indications greater than 35%, monitoring for IR indications between 16% and 35%, and no action for IR indications less than

16%. An IR indication of 10% or greater, coincidental with a top-side dent also requires immediate action.[10] The DCVG survey resulted in a 2% IR indication directly over the failure location, so it was not acted upon. The RCFA offered some considerations for the relatively minor IR indication compared to the mechanical damage that had been sustained. It is believed that the existence of concrete weights and the increased depth of cover associated with the installation affected the results of the DCVG survey, but the extent of this affect is not quantifiable.

TransCanada performed a high resolution magnetic flux leakage (MFL) and caliper ILI in September of 2012. Another ILI was performed using a different tool vendor in May of 2016. Neither of these assessments detected metal loss in excess of 10% within 500 feet of the failure location. Additionally, no geometry features were identified near the failure location by either caliper tool. After the accident, the ILI data was reviewed at a high sensitivity level in an effort to see what, if any, indications could be identified associated with the failure location. No metal loss was detectable, and only a slight deformation was observed associated with the mechanical damage. The limited capability of the tool(s) to detect the gouges that were sustained during original construction was determined to be a causal factor to the accident.

TransCanada's fatigue analysis for the SP estimated that a theoretical flaw 4-inches long and 0.016-inches deep (detection threshold of pipe mill NDE) would not grow to failure within 35 years of operation. This analysis is not applicable to the cold-worked mechanical damage that was sustained at the failure location.[11] The rupture defect failed within 7.4 years of operation. The pressure spectrum the pipeline was subjected to over the history of operation is notable. The pipeline was limited to an MOP of 1296 psig (72% SMYS) from June of 2010 until November of 2014. From November of 2014 until October of 2016 the MOP was limited to 1338 psig (74.2% SMYS). From October of 2016 until the failure occurred, the MOP was 1440 psig (80% SMYS). There were additional threat mitigation activities that have taken place during the operational history of the pipeline which have resulted in a number of relatively high amplitude pressure cycles. High amplitude pressure cycles can contribute significantly to defect growth, and may sometimes be represented by ratchet marks, like those that were evident within the fracture surface. The contribution of operating pressure cycles to the growth and ultimate failure of the rupture defect is a contributing factor to the accident.

TransCanada's OCC identified the failure, and the pipeline controller initiated emergency actions, very quickly. This limited the amount of oil discharged immediately as a result of the rupture to a nearly ideal scenario. The rupture opening was also very near the top of the pipe, significantly limiting the amount of product drained by gravity, compared with a failure on the bottom side of the pipe. The volume of oil spilled as a result of this accident is contributed to

[10] Topside Dent – A dent on the top of the pipe is indicative of outside force damage, possibly by a backhoe bucket tooth or other mechanical damage.
[11] Cold-worked – metal striking steel at ambient temperature can change the micro-structure and cause the metal to harden and become brittle.

greatly by the amount estimated to have drained from the pipeline by gravity. The elevation throughout the area of the failure is relatively consistent, so the gravity-drain from the pipeline likely occurred fairly slowly due to minimal head-pressure. The installation of stopple fittings upstream and downstream of the rupture were not completed until November 25th, nine days after the rupture. It is unknown whether, or to what extent, the length of time taken to install the stopple fittings may have contributed to the volume of oil released due to gravity-drain.

Findings and Contributing Factors

The accident occurred as a result of mechanical damage that was sustained during original construction of the pipeline. The damage was not discovered, detected, or reported at the time it was sustained. The resulting defect survived the post-construction hydrostatic pressure test. The failure defect existed when the pipeline was placed in service, and grew incrementally as a result of operational pressure cycles (fatigue crack growth). The defect was not detected as a result of multiple surveys and ILI assessments that were performed following construction and throughout operation of the pipeline.

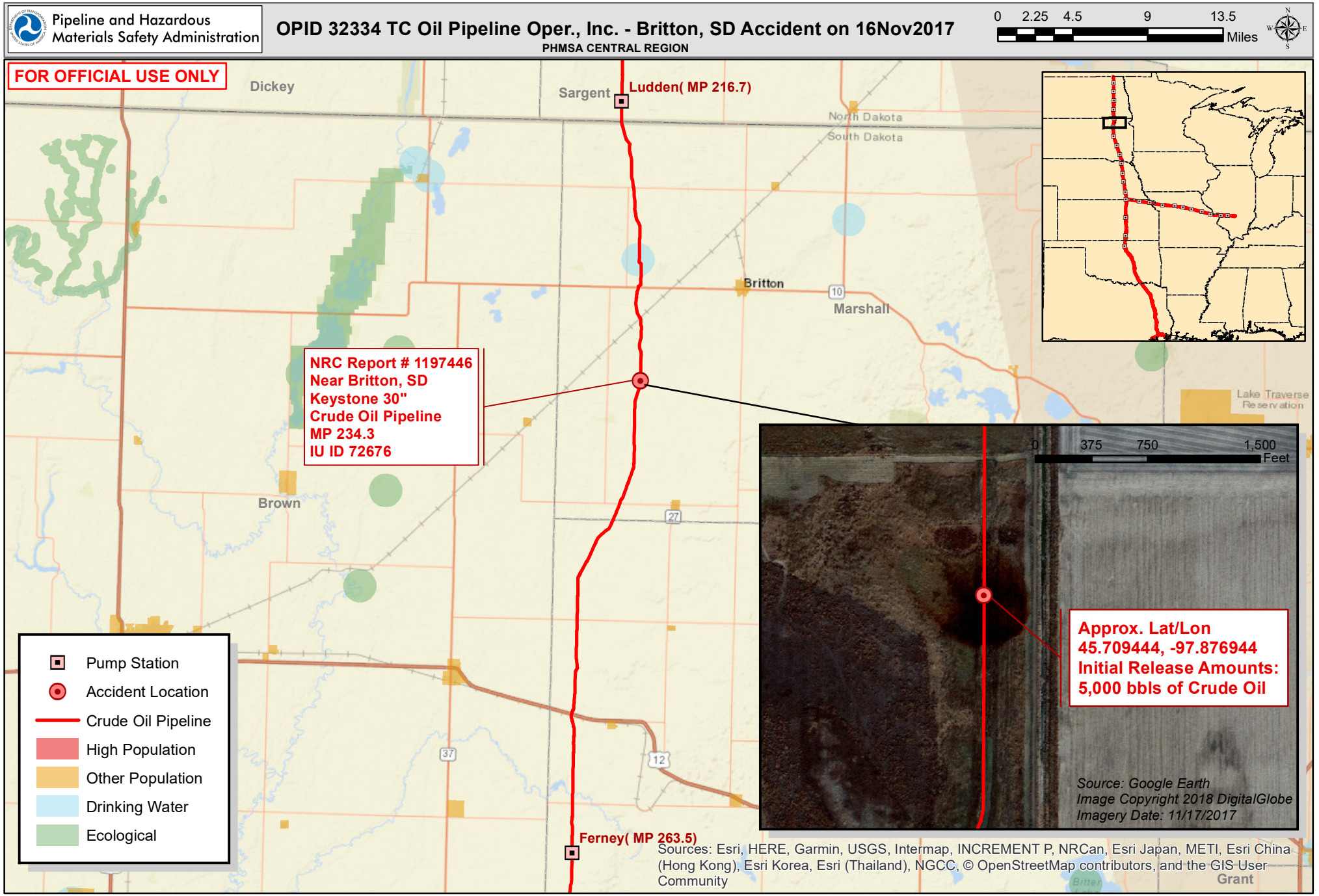
The rupture defect grew to failure within 7.4 years of operation. It should be assumed that similar damage could be sustained at any time throughout operation of the pipeline, and not be discovered, reported and/or detected at the time it is sustained. There is existing ILI technology capable of detecting these types of defects. Conservative assessment intervals will improve the probability of detection prior to failure.

Appendices

Appendix A – Map and Photographs
Appendix B – NRC Reports
Appendix C – Operator's Written Report
Appendix D – NTSB Metallurgical Examination Factual Report
Appendix E – Root Cause Failure Analysis

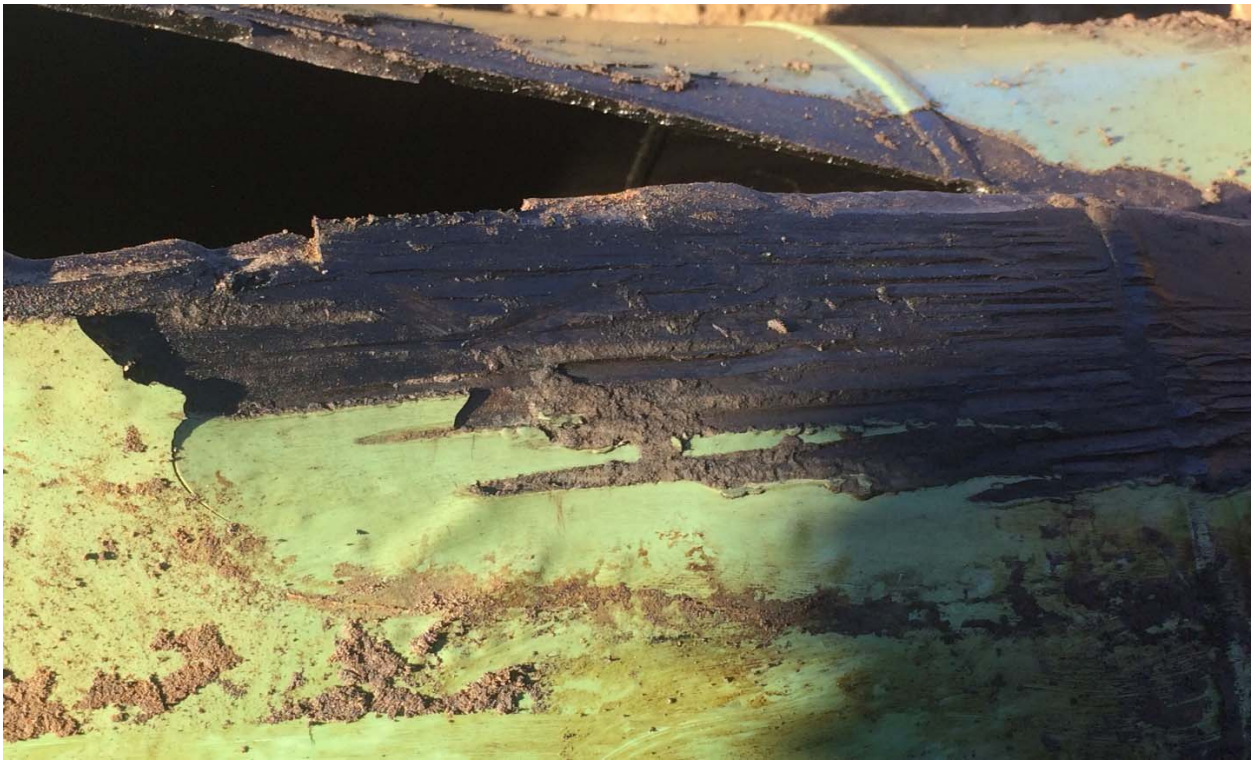
Appendix A

Maps and Photographs


Pipeline and Hazardous Materials Safety Administration
OPID 32334 TC Oil Pipeline Oper., Inc. - Britton, SD Accident on 16Nov2017
PHMSA CENTRAL REGION
0 2.25 4.5 9 13.5 Miles
FOR OFFICIAL USE ONLY
Dickey
Sargent
Ludden(MP 216.7)
North Dakota
South Dakota
Britton
10
Marshall
NRC Report # 1197446
Near Britton, SD
Keystone 30"
Crude Oil Pipeline
MP 234.3
IU ID 72676
Brown
Lake Traverse Reservation
27
37
12
0 375 750 1,500 Feet
Approx. Lat/Lon
45.709444, -97.876944
Initial Release Amounts:
5,000 bbls of Crude Oil
Source: Google Earth
Image Copyright 2018 DigitalGlobe
Imagery Date: 11/17/2017
Pump Station
Accident Location
Crude Oil Pipeline
High Population
Other Population
Drinking Water
Ecological
Ferney(MP 263.5)
Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community
Grant

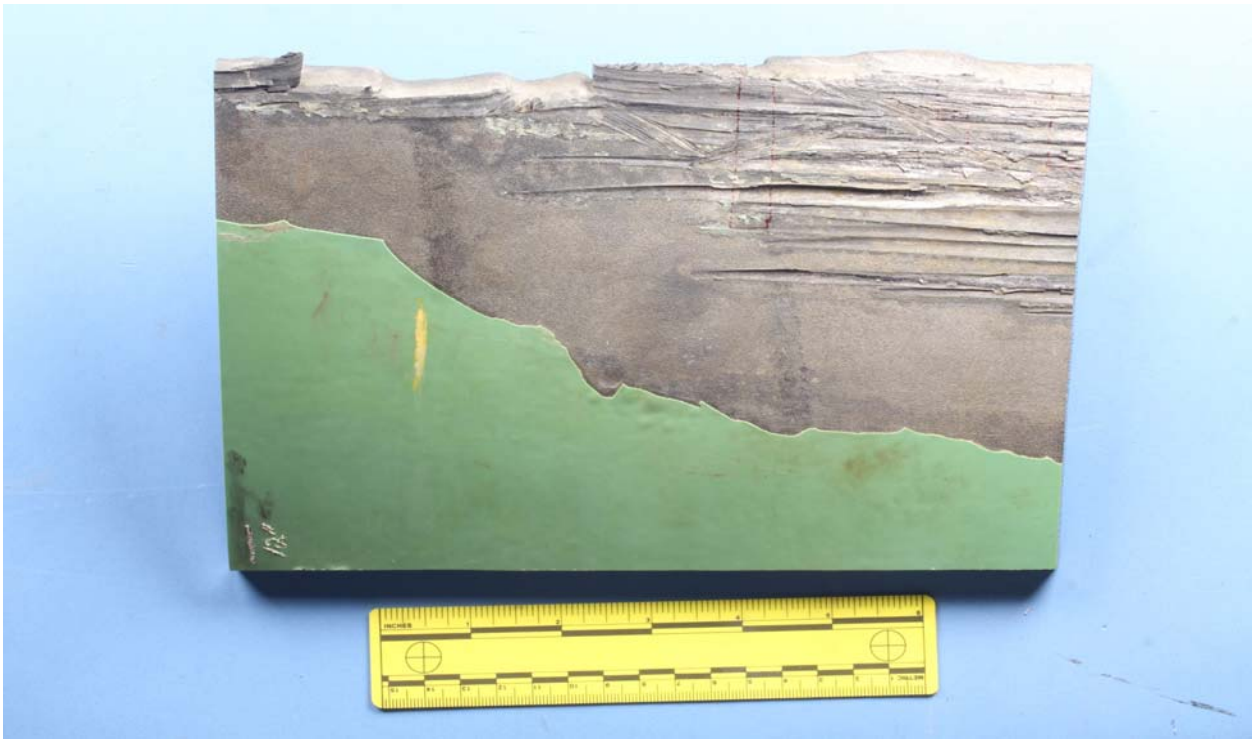
In-Situ Ruptured Pipe Examination

Additional Gouges Adjacent to Rupture Opening



NTSB Photo – Rupture Opening – Opposing Fracture Surfaces

NTSB Photo – Additional Gouges Adjacent to Rupture Opening



NTSB Photos - Rupture Origin – Fracture Surface

NTSB Photo – Rupture Origin – Dark Contrast

Appendix B

NRC Reports

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1197446

INCIDENT DESCRIPTION

*Report taken by: CIV JUSTIN MURRAY at 11:17 on 16-NOV-17
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area:
Incident occurred on 16-NOV-17 at 09:15 local incident time.
Affected Medium: LAND / DIRT, SOIL, VEGETATION

REPORTING PARTY
Name: ERIK HUGHES
Organization: TRANSCANADA
Address: 13710 FIRST NATIONAL BANK PKWY
OMAHA, NE
Email Address: erik_hughes@transcanada.com

PRIMARY Phone: (402)4907253
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: ERIK HUGHES
Organization: TRANSCANADA
Address: 13710 FIRST NATIONAL BANK PKWY
OMAHA, NE
PRIMARY Phone: (402)4907253
Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
SEE LAT AND LONG County: MARSHALL
City: BRITTON State: SD
Latitude: 45° 42' 28" N
Longitude: 097° 52' 36" W

RELEASED MATERIAL(S)
CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 5000 BARREL(S)

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A DISCHARGE OF CRUDE OIL FROM A TRANSMISSION PIPELINE ONTO THE GROUND. THE DISCHARGE WAS DETECTED VIA SENSORS FROM THE CONTROL CENTER.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air:	N		
Road:	N	Major Artery:N	
Waterway:	N		
Track:			

Environmental Impact: YES/VEGETATION
Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS

MADE NOTIFICATIONS. CONTRACTORS AND LOCAL RESPONDERS ARE ON SCENE.
PIPELINE HAS BEEN SHUT IN.
Release Secured: YES
Release Rate:

Estimated Release Duration:

WEATHER

Weather: UNKNOWN, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
16-NOV-17 11:25 (770)4887100
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGI
16-NOV-17 11:25 (703)7673477
DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)
16-NOV-17 11:25 (703)2359349
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
16-NOV-17 11:25 (202)3661863
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE)
16-NOV-17 11:25 (202)5643850
U.S. EPA VIII (MAIN OFFICE)
(303)2931788
U.S. EPA VIII (OIL POLLUTION ACT ENFORCEMENT PRGM)
16-NOV-17 11:25 (303)3126608
IA U.S. ATTORNEY'S OFFICE (INTELLIGENCE OFFICER)
16-NOV-17 11:25 (515)4739345
NE INFORMATION ANALYSIS CENTER (MAIN OFFICE)
16-NOV-17 11:25
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
16-NOV-17 11:25 (202)2829201
NOAA RPTS FOR SD (MAIN OFFICE)
16-NOV-17 11:25 (206)5264911
NRC COMMAND DUTY OFFICER (MAIN OFFICE)
(202)2672100
NTSB PIPELINE (MAIN OFFICE)
16-NOV-17 11:25 (202)3146293
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
16-NOV-17 11:25 (202)3660568
PACIFIC STRIKE TEAM (MAIN OFFICE)
16-NOV-17 11:25 (415)8833311
REPORTING PARTY (RP SUBMITTER)
16-NOV-17 11:25

SOUTH DAKOTA DENR (MAIN OFFICE)
  16-NOV-17 11:25 (605)7733296
DOI/OEPC DENVER (MAIN OFFICE)
  16-NOV-17 11:25 (303)4452500
USCG DISTRICT 8 (MAIN OFFICE)
  16-NOV-17 11:25 (504)5896225

ADDITIONAL INFORMATION
CALLER WILL BE MAKING ADDITIONAL NOTIFICATIONS.

*** END INCIDENT REPORT #1197446 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1197610

INCIDENT DESCRIPTION

*Report taken by: CIV LEONARD NEWSOM at 12:25 on 18-NOV-17
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident occurred on 16-NOV-17 at 09:15 local incident time.
Affected Medium: LAND DIRT, SOIL, VEGETATION

REPORTING PARTY
Name: ERIK HUGHES
Organization: TRANSCANADA
Address: 13710 FIRST NATIONAL BANK PKWY
OMAHA, NE
Email Address: erik_hughes@transcanada.com

PRIMARY Phone: (402)4907253
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: ERIK HUGHES
Organization: TRANSCANADA
Address: 13710 FIRST NATIONAL BANK PKWY
OMAHA, NE
PRIMARY Phone: (402)4907253
Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
County: MARSHALL
City: BRITTON State: SD
SEE LAT AND LONG

RELEASED MATERIAL(S)
CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 5000 BARREL(S)

DESCRIPTION OF INCIDENT

/// UPDATE TO NRC INCIDENT REPORT # 1197446 ///

THIS A 48 HOUR UPDATE UNDER PHMSA REGUALTIONS.

UPDATE: THERE ARE NO CHANGES, OR UPDATES AT THIS TIME

ORIGINAL REPORT: CALLER IS REPORTING A DISCHARGE OF CRUDE OIL FROM A TRANSMISSION PIPELINE ONTO THE GROUND. THE DISCHARGE WAS DETECTED
VIA SENSORS FROM THE CONTROL CENTER.

/// UPDATE TO NRC INCIDENT REPORT # 1197446 ///

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air: N			
Road: N	Major Artery:N		
Waterway: N			
Track:			

Environmental Impact: YES/VEGETATION
Media Interest: UNKNOWN Community Impact due to Material:

REMEDIAL ACTIONS

MADE NOTIFICATIONS. CONTRACTORS AND LOCAL RESPONDERS ARE ON SCENE.
PIPELINE HAS BEEN SHUT IN.

Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
18-NOV-17 12:37 (770)4887100
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGI
18-NOV-17 12:37 (703)7673477
DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)
18-NOV-17 12:37 (703)2359349
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
18-NOV-17 12:37 (202)3661863
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE)
18-NOV-17 12:37 (202)5643850
U.S. EPA VIII (MAIN OFFICE)
(303)2931788
U.S. EPA VIII (OIL POLLUTION ACT ENFORCEMENT PRGM)
18-NOV-17 12:37 (303)3126608
IA U.S. ATTORNEY'S OFFICE (INTELLIGENCE OFFICER)
18-NOV-17 12:37 (515)4739345
NE INFORMATION ANALYSIS CENTER (MAIN OFFICE)
18-NOV-17 12:37
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
18-NOV-17 12:37 (202)2829201
NOAA RPTS FOR SD (MAIN OFFICE)

18-NOV-17 12:37 (206)5264911
NTSB PIPELINE (MAIN OFFICE)
18-NOV-17 12:37 (202)3146293
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
18-NOV-17 12:37 (202)3660568
PACIFIC STRIKE TEAM (MAIN OFFICE)
18-NOV-17 12:37 (415)8833311
REPORTING PARTY (RP SUBMITTER)
18-NOV-17 12:37
SOUTH DAKOTA DENR (MAIN OFFICE)
18-NOV-17 12:37 (605)7733296
DOI/OEPC DENVER (MAIN OFFICE)
18-NOV-17 12:37 (303)4452500
USCG DISTRICT 8 (MAIN OFFICE)
18-NOV-17 12:37 (504)5896225

ADDITIONAL INFORMATION
/// UPDATE TO NRC INCIDENT REPORT # 1197446 ///

*** END INCIDENT REPORT #1197610 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

Appendix C

Operator's Written Report

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 8/31/2020
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	12/16/2017
	No.	20170417 - 31163 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**
Last Revision Date:	11/09/2018		
1. Operator's OPS-issued Operator Identification Number (OPID):	32334		
2. Name of Operator	TC OIL PIPELINE OPERATIONS INC		
3. Address of Operator:			
3a. Street Address	Bank of America Center - 700 Louisiana Street		
3b. City	Houston		
3c. State	Texas		
3d. Zip Code	77002-2700		
4. Local time *(24-hr clock)* and date of the Accident:	11/16/2017 05:33		
5. Location of Accident:			
Latitude:	45.709444		
Longitude:	-97.876944		
6. National Response Center Report Number (if applicable):	1197446		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	11/16/2017 10:13		
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil		
- Specify Commodity Subtype:			
- If "Other" Subtype, Describe:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100			
9. Estimated volume of commodity released unintentionally (Barrels):	6,592.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):			
11. Estimated volume of commodity recovered (Barrels):	6,592.00		
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			
12b. Contractor employees working for the Operator			
12c. Non-Operator emergency responders			
12d. Workers working on the right-of-way, but NOT associated with this Operator			
12e. General public			
12f. Total fatalities (sum of above)			
13. Were there injuries requiring inpatient hospitalization?	No		
- If Yes, specify the number in each category:			
13a. Operator employees			
13b. Contractor employees working for the Operator			
13c. Non-Operator emergency responders			
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e. General public			

13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	11/16/2017 05:33
14b. Local time pipeline/facility restarted:	11/29/2017 10:00
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	11/16/2017 05:36
18b. Local time Operator resources arrived on site:	11/16/2017 09:15

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	South Dakota
3. Zip Code:	57421
4. City	Not Within a Municipality
5. County or Parish	Marshall County
6. Operator-designated location:	Milepost/Valve Station
Specify:	MP 234.3
7. Pipeline/Facility name:	Keystone Pipeline
8. Segment name/ID:	KS6
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	48
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe
- If Pipe, specify:	Pipe Body
3a. Nominal diameter of pipe (in):	30

3b. Wall thickness (in):	.386
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	70,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	Berg
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Accident, specify:	Fusion Bonded Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2008
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other, Describe:	
Approx. size: in. (widest opening) by	11.3
in. (length circumferentially or axially)	52
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	Yes
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	Yes
- Terrestrial	Yes
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	No
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's	

Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 823,400
8b. Estimated cost of commodity lost	$ 583,560
8c. Estimated cost of Operator's property damage & repairs	$ 5,682,477
8d. Estimated cost of Operator's emergency response	$ 6,042,594
8e. Estimated cost of Operator's environmental remediation	$ 31,677,529
8f. Estimated other costs	$ 0
Describe:	All costs are final as of 20180724.
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 44,809,560

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,067.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	1,440.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below)* effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	125,664
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply*)	

- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G5 - Material Failure of Pipe or Weld

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	

- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	

5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	

- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column

Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	Construction-, Installation-, or Fabrication-related
1. The sub-cause shown above is based on the following: *(select all that apply)*	

- Field Examination	
- Determined by Metallurgical Analysis	Yes
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	Yes
Specify:	Pressure-related
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	Yes
- Pipe Bend	
- Arc Burn	
- Crack	Yes
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2016
- Ultrasonic	
Most recent year run:	
- Geometry	Yes
Most recent year run:	2016
- Caliper	Yes
Most recent year run:	2016
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	Yes
Most recent year run:	2017
Describe:	Acoustic Leak Detection
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	No
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	No
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	

- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	

- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On 16 Nov, 2017, at 05:34 CST, a pressure drop was experienced on Keystone approximately 17.4 miles downstream of Ludden Pump Station, resulting in the pipeline being shut down. At 09:15, technicians confirmed oil on the ground. At 10:13 CST, the NRC was called, and a report generated (1197446) and distributed at 10:26. Contact with PHMSA Accident Investigation Division made at 1025; PHMSA on site from 17 to 28 Nov. Pipeline was subsequently restarted on 29 Nov after replacement of failed section. Metallurgical testing being performed by the National Transportation Safety Board; results pending. Regarding Part D, 1a., there one bird and one raccoon were lost.

20180315 Supplemental Report: Updated commodity released and recovered, costs associated with the accident, and cause of the failure (second party damage) as derived from the National Transportation Safety Board (NTSB) draft metallurgic report, and confirmed by a mutually agreed upon third party contractor, Keifner and Associates.

20180810 Supplemental Report: Final costs received and vetted through leadership on 20180724, with approval on 20180801.

20180822 - Updated Part G Apparent Cause to a G5 from a G8, and Part E for controller investigation.

20181109 - Updated Part A volume released to 6,592 bbls; volume derived through Pipe Integrity calculation based on exact location, depth of cover, actual shutdown times, and position of the rupture.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Erik Hughes
Preparer's Title	US Regulatory Compliance Manager
Preparer's Telephone Number	4024907253
Preparer's E-mail Address	erik_hughes@transcanada.com
Preparer's Facsimile Number	
Authorized Signer Name	Sonya Kirby
Authorized Signer Title	Vice President - Safety Quality and Compliance
Authorized Signer Telephone Number	4039207255
Authorized Signer Email	sonya_kirby@transcanada.com
Date	11/09/2018