

Slurry Abrasion Failure Of A Carbon Steel Pipe Carrying Bitumen Froth In Oil Sands

Reinaldo J Chung
Suncor Energy Inc.
150 6 Ave SW
Calgary, AB, T2P 3E3
Canada

Jiaren (Jimmy) Jiang
Mining Wear and Corrosion Laboratory
National Research Council Canada
4250 Wesbrook Mall
Vancouver, BC, V6T 1W5
Canada

Naveen Prathap
Suncor Energy Inc.
150 6 Ave SW
Calgary, AB, T2P 3E3
Canada

Darren Ting
Suncor Energy Inc.
150 6 Ave SW
Calgary, AB, T2P 3E3
Canada

Shawn Chen
Suncor Energy Inc.
150 6 Ave SW
Calgary, AB, T2P 3E3
Canada

Marilyn Garcia
Suncor Energy Inc.
150 6 Ave SW
Calgary, AB, T2P 3E3
Canada

ABSTRACT

In this paper, the premature failure of a carbon steel pipe carrying bitumen froth (60 to 90°C; 1,040 kg/m³ density) from oil sands primary extraction is analyzed. The leak developed at approximately 1,000 m downstream the pumps' discharge on an underground sloped section of the pipeline and was due to the thinning of the pipe wall. An extensive investigation was conducted including detailed visual and microscopic examination, mechanical testing, froth and solids abrasivity characterization, and hydraulics analysis. Various laboratory tests were performed to simulate different wear and corrosive-wear conditions in order to replicate and better understand the failure. Results showed that despite slurry erosion to be the expected damage mechanism, the failure was actually caused by a slurry abrasion process. This can create thickness loss rates much more aggressive than those expected by an erosive process under similar conditions. A new wear mechanism is proposed to explain the observed results.

Key words: Erosion; erosion-corrosion; metallurgical failures; reliability; wear; pipelines; oil sands; froth

INTRODUCTION

On January 2017, Suncor experienced a process released on the Steepbank froth pipeline in Base Plant, north of Fort McMurray, Canada. The pipeline is approximately 4,500 m in length x 711.2 mm OD (NPS 28) x 12.7 mm WT carrying primary froth from the Steepbank Primary Extraction Plant to the Secondary Extraction Plants for further processing. The entire pipeline length is contained within plant battery limits and partially underground, and goes through a significant elevation change, starting at 330 m at the start of the line, reaching 243 m elevation at the lowest point, and 295 m at the interstage tank in Secondary Extraction where the line discharges the froth (Figure 1). The pipeline operates at a flow rate of 500 m³/h to 3,000 m³/h, 60 to 88°C, and the viscosity varies between 400 to 2,700 cP at a density of 1,040 kg/m³.

The pipeline was fabricated and commissioned in 2009, and it was built of carbon steel API 5L Gr.B material [1]. Other froth lines in the plants had been built of similar carbon steel grade or higher strength low alloy steels such as API 5L X65, which have been running for over 20 yr. without reaching significant thickness losses.

The failure location was in a sloped section between 900 m to 1,100 m from the Steepbank Plant, and exhibited severe wall thickness loss with a split over 12 m long (Figure 2), which resulted in 600 m of pipeline to be replaced due to thinning. In order to understand the thinning mechanism(s) leading to such premature failure, an extensive failure investigation was conducted including detailed visual and microscopic examination, mechanical testing, froth and solids abrasivity characterization, and hydraulics analysis. Various laboratory tests were performed to simulate different wear and corrosive-wear conditions in order to replicate the damage and better understand the failure.



Figure 1: Steepbank primary froth line routing and elevation changes.



Figure 2: Failed spool after removal from the pipeline, showing the split at the 6 o'clock position propagated on a fairly straight manner over 12 m in length.

SYSTEM OVERVIEW

The primary extraction bitumen froth typically contains about 20 Wt.% water and 12 Wt.% minerals fines (less than 44 μm size) which floats off the top of the primary separation cells [2-4]. In this process air is essential in the downstream bitumen recovery process, in that air bubbles are required to attach to the oil droplets in order to enable them to rise to the surface in the separation cells. The air content of the froth is reduced in static deaerators before being transported through pipelines for further downstream removal of water and minerals in the Froth Treatment or Secondary Extraction Plants [2-5] to produce the synthetic bitumen. In order to increase the bitumen recovery rates in the extraction process, other secondary and tertiary separation loops from another stream off the primary separation cells called middlings are utilized [2,4]. The middlings are located under the froth layer where the slurry does not have enough air content or attaches to fine minerals which prevents it from floating to the froth layer [2-4]. The recovered bitumen from the secondary and tertiary separation cells floats off the top as froth and is pumped back into the primary separation cell feed. The underflow tailings (coarse tails) are collected in sumps and pumped to tailings ponds by centrifugal slurry pumps [2-9]. Figure 3 shows a schematic diagram of the primary separation process [2].

The specific Steepbank Froth pipeline fluid composition and operating conditions are specified in Table 1. The pipeline froth specific gravities are in the range of 1.01 to 1.06 with a water fraction of 30 to 37 wt.%.

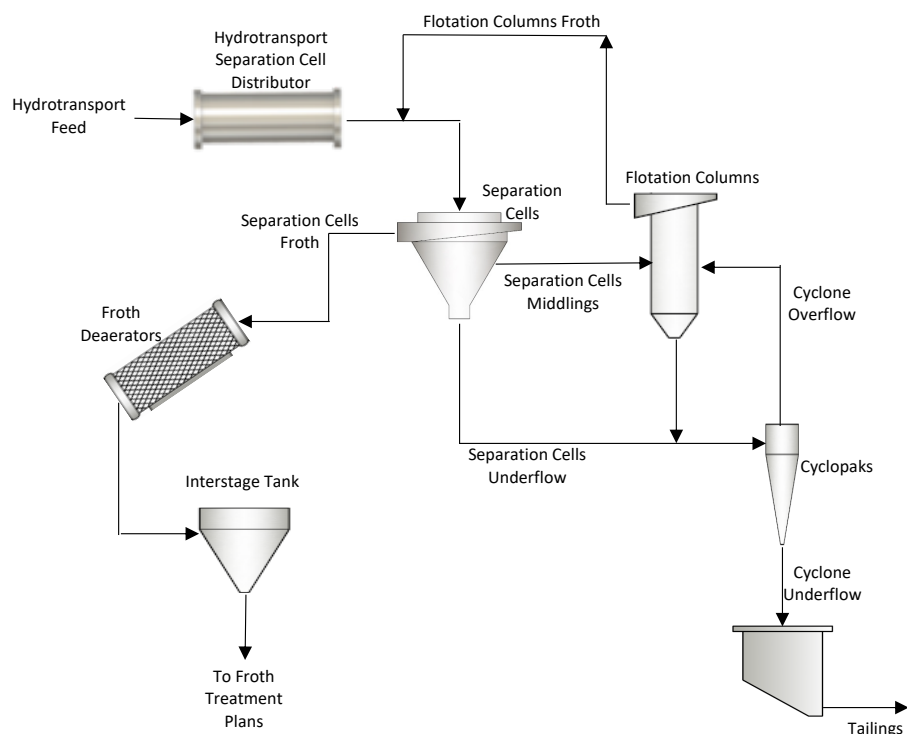


Figure 3: Steepbank primary froth line routing and elevation changes.

Table 1 Steepbank froth characteristics.

Parameter	Units	Maximum	Average	Minimum
Bitumen	t/h	1485	1286	359
Water	t/h	1016	852	230
Silica Sand (+44µm)	t/h	28	23	6
Fines Minerals (-44µm)	t/h	214	174	57
Air	t/h			
TOTAL MASS	t/h	2743	2335	765
Bitumen	wt. %	54.1	46.9	46.9
Water	wt. %	37	31.1	30
Silica Sand (+44µm)	wt. %	1	0.8	0.8
Fines Minerals (-44µm)	wt. %	7.8	6.3	7.4
Air Content	vol. %	15	7	1
Specific Gravity	N/A	1.06	1.03	1.02
Volume Flow	m ³ /h	2689	2000	750
Temperature	°C	88	72	60
Clay content	wt. %	35	27	20
Quartz	wt. %	65	50	40

FAILURE ANALYSIS

3.1 Field Visual Examination and Line Inspection

Visual examination of the failed pipeline section revealed that the thinning mechanism was completely developed from the internal surface, with the external fusion bonded epoxy coating still intact with no visible signs of coating damage or external corrosion. The thickness profile was consistent along the length of the failed section of the pipeline, featuring a sharp thickness change from nominal thickness (12.7 mm) towards the bottom of the pipe where it reaches less than 1.5 mm near the split. The thickness loss was mainly confined within the 4 to 8 o'clock position at the bottom of the pipe (Figure 4). There was no evidence of preferential thickness loss at the longitudinal seam and girth welds. The low thickness profile at the bottom of the pipe extended over a section of approximately 600 m beyond which the pipeline thickness recovered to nominal values in all o'clock positions both upstream and downstream of the affected section. This indicated that the phenomenon must have been driven by a change in the hydraulics / flow dynamics that triggered a more aggressive thickness loss rates or a change in the degradation mechanism able to cause significantly more damage than under pure mechanical erosion. It was also evident that with less than 1.5 mm at the bottom of the pipe the final failure event occurred due to ductile overload as the pipe thickness was not enough to withstand the internal pressure.

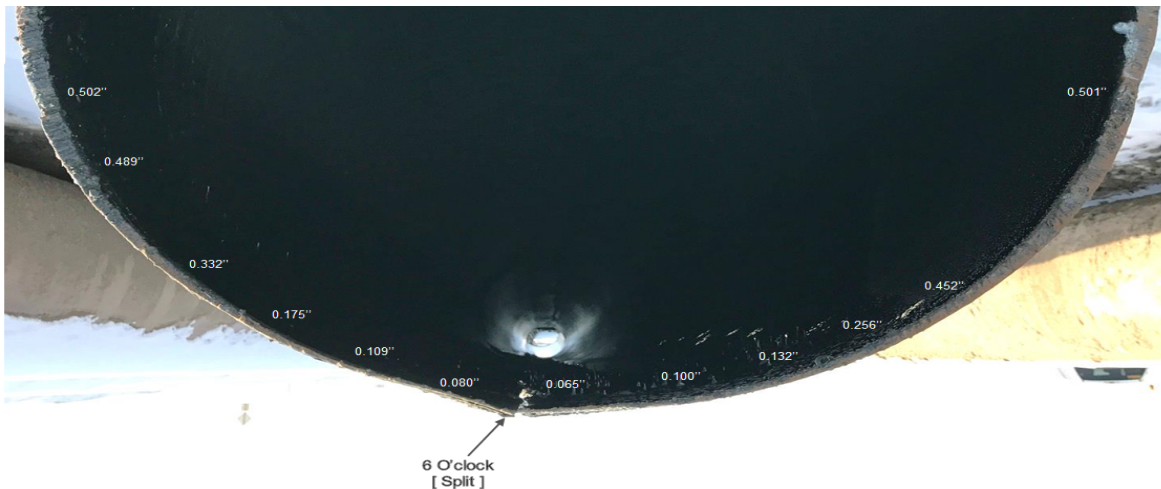


Figure 4: Typical thickness profile throughout the cross section of the failed pipe.

Inspection of the line mainly consisted of a number of ultrasonic bands that were permanently installed on the pipeline each taking daily readings at each of the 12 o'clock positions. In addition to this, there were yearly visual inspections and manual UT thickness measurements taken at the start of the line at the pump discharge and at the end of the line near the discharge into the froth tank. All inspection results collected up to the time of the failure had indicated thickness near nominal with maximum thickness loss rates of up to 0.25 mm/yr. This was consistent with the thickness loss rates measured in other froth pipelines on site which had been in service for much longer. Froth has been typically one of the most benign slurry services in the oil sands surface mining operation causing little wall loss, hence carbon steel has been suitable to handle the service.



Figure 5: Pipe section cut out of the failed spool for further analysis.

3.2 Visual and Optical Microscopy Examination of a Pipe Sample after Cleaning

A section of approximately 0.6 m long representative of the failure was selected and cut out from the failed spool for further analysis in the lab (Figure 5). After cleaning of the internal surface to remove the bitumen that was stuck to the surface (Figure 6), it was evident that the final failure was ductile, with clear plastic deformation along the split. It also became evident that there were two distinct zones in the pipe internal surface that were consistent with the areas of nominal thickness and the area with pronounced thickness loss, respectively. The inner surface of the pipe surrounding the rupture line (within an angle of about 135°) was shiny while the rest of the pipe surface was dull with light oxide scale. The pipe wall thickness changed rapidly within this shiny region, from less than 1 mm thick at the rupture to about 12.5 mm at the boundary (shiny/light rust) which was almost the same as the original pipe wall thickness. That is, wear occurred mainly in this 135° sector while the rest was intact.

A closer examination of the internal surfaces revealed the presence of clear long scratching/abrasion scars near the boundary between the shiny and light rusty surface, covering approximately a 75 mm wide area (Figure 7). The more severely worn pipe surface (around the rupture) is characterized by sand-beach like wave patterns superimposed by longitudinal scratches. Optical microscopy of these distinct areas of the internal surface can be seen in Figure 8, depicting in more details the scratching lines near the boundary of severe wear (Figure 8(a) & (b)), and wavy wear surface in the more severe wear region, (Figure 8(c)). There appears to be small shallow oxide pits in the surface indicative that even though the damage appears to be wear dominant, corrosive-wear is commonly a factor when dealing with slurries.

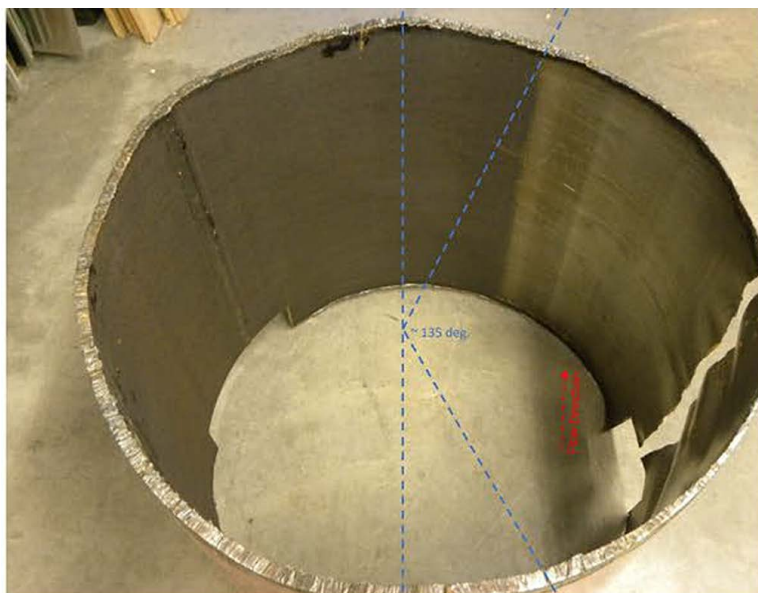


Figure 6: Pipe section cut out for laboratory testing, after cleaning of the bitumen products.

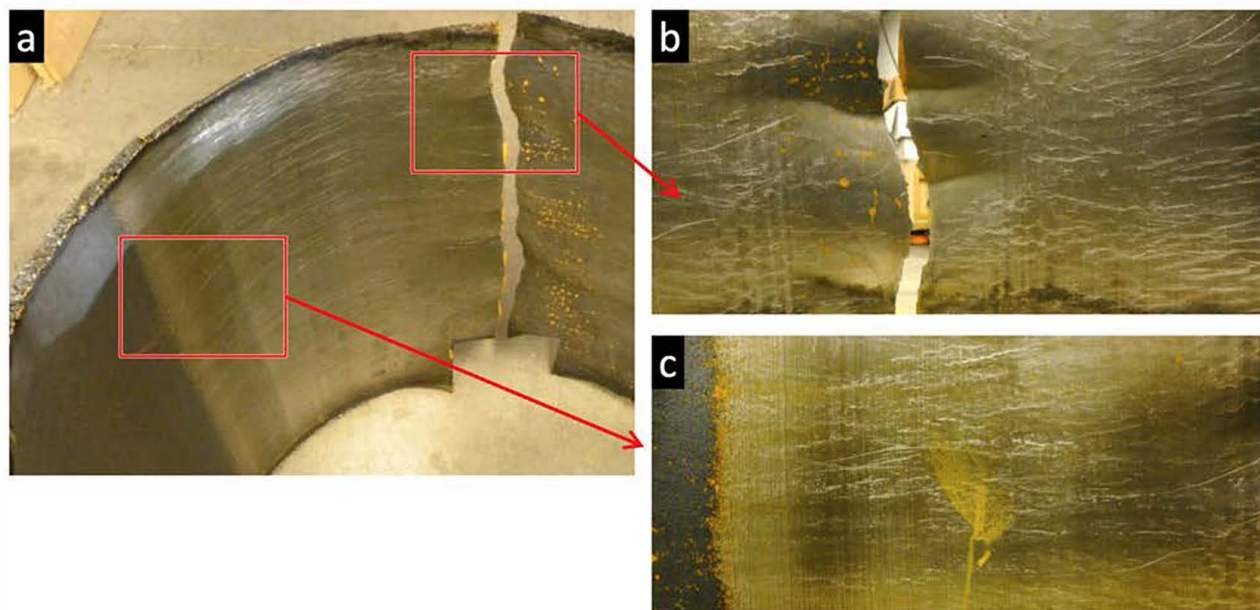


Figure 7: A closer look at the internal surfaces of the pipe cut out after cleaning.

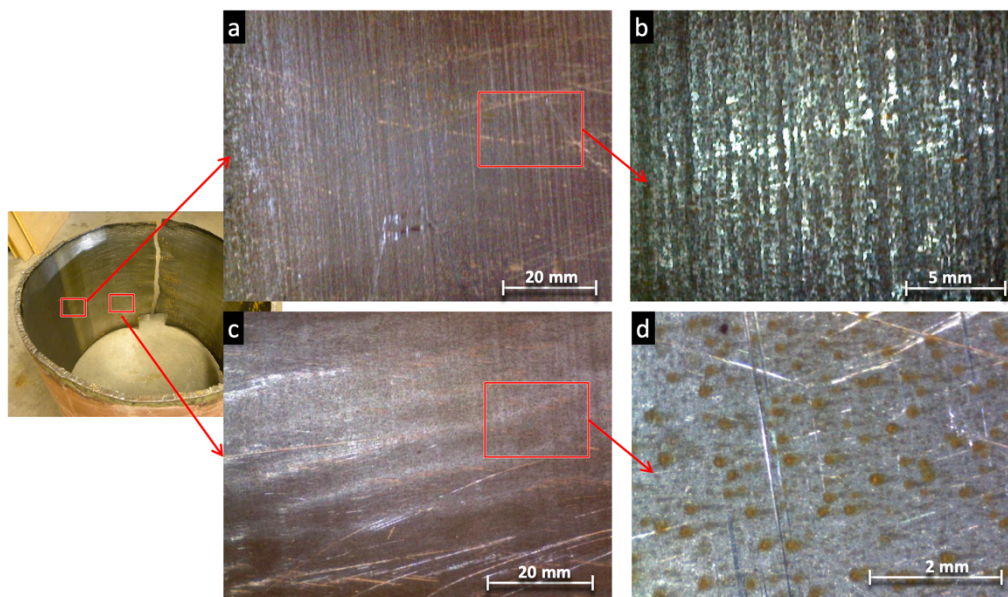


Figure 8: Optical micrographs obtained on areas of the internal surface near the transition between the lightly rusty /shiny areas (a and b); and near the rupture (c and d).

3.3 Scanning Electron Microscopy (SEM) Examination

Figure 9 shows the SEM micrographs obtained at the suspected initiation location of the longitudinal split or fracture at the bottom of the pipe, approximately at the 6 o'clock position. The fractographic features confirmed the pipe rupture was clearly ductile, featuring shear lips (Figure 9(a)), plastic deformation ridges (Figure 9(b)), and dimples (Figure 9(c)) [10].

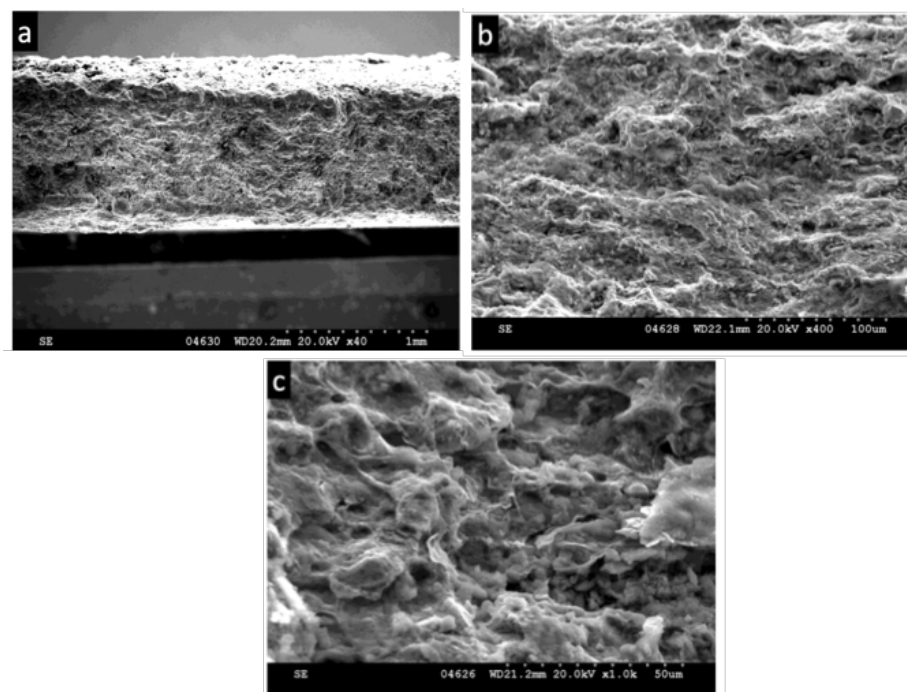


Figure 9: SEM micrographs at the split or fracture surface, featuring ductile features.