Canadian Crude Quality Technical Association

Update on Projects Related to Corrosion and Pipeline Integrity

June 8, 2016

Trevor Place, Enbridge Pipelines

Pipeline Corrosion Project

Sour Service Project

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Pipeline Corrosion Project

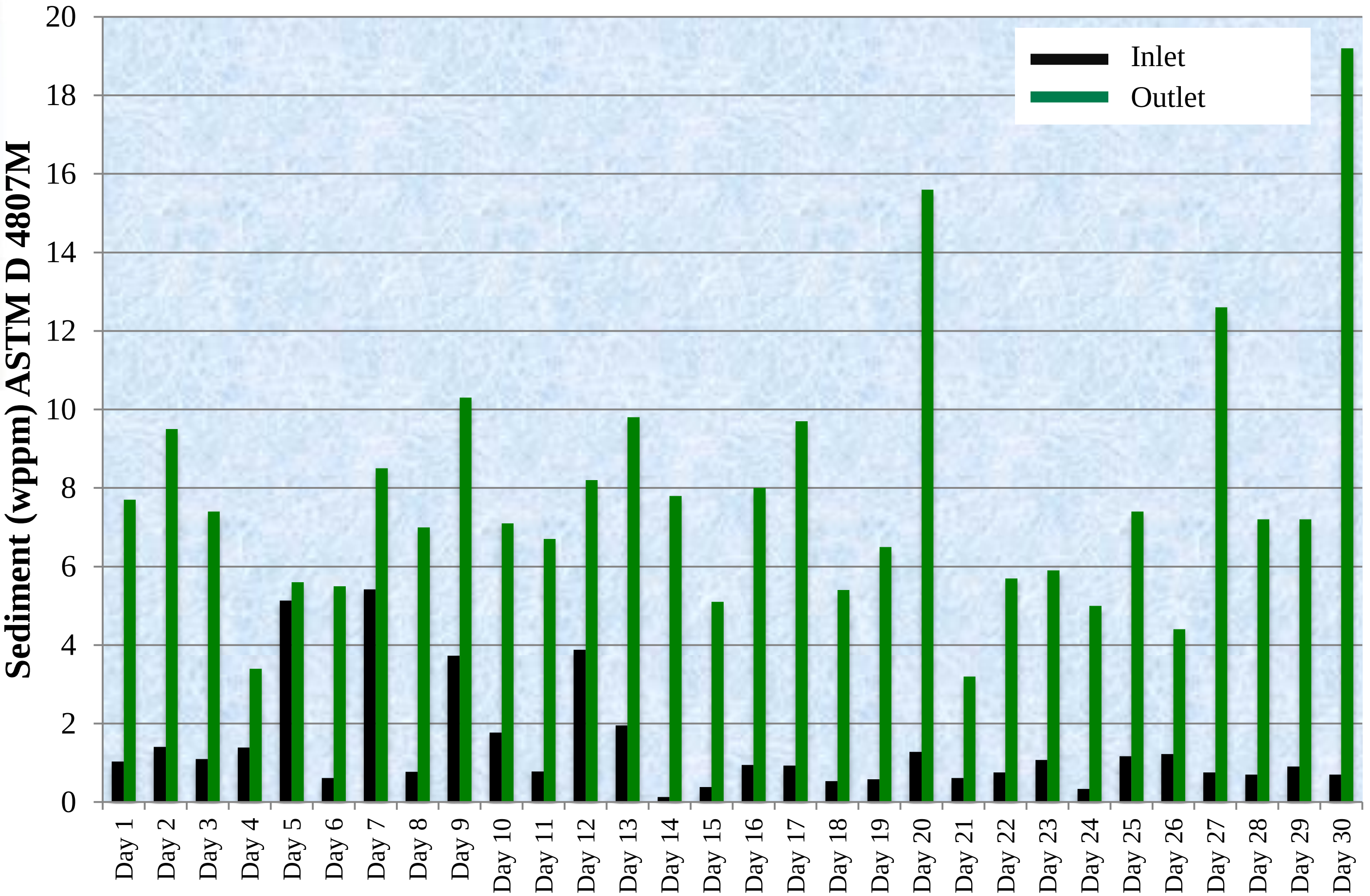
- Background/Need
  - FACT: Many corrosion models exist to predict corrosion rates in multiphase oil and gas systems
  - ISSUE: TX pipeline operators rarely have gas pp
- Objective
  - To develop a test method for measuring O_2, CO_2 & H_2S in stabilized crude
  - To assess and/or develop at line/on line monitoring equipment that can be used to assess real-time corrosion threat in stabilized crude
- Status
  - Test method for gas measurement “ready to go”
  - Preliminary assessment of TM0172 & ASTM G205
  - Considerable effort has been diverted to the Sour Service Project (which also leverages efforts from the H2S PVT Project)

Pipeline Corrosion Project

- Active Membership (8):
  - ADOE, Cenovus, Enbridge, IOL, Kinder Morgan, Nalco/Champion, Suncor, TCPL
- Financials:
  - $40K allocated in 2016 for ongoing technology development (AITF)
- 2016 Milestone/Targets:
  - AITF working on the development of GC based method for O_2, CO_2 & H_2S measurement in pipelined materials
    - Crude oils, condensates, synthetics, Intermediates, Finished products, etc.
  - Exploring option of using alternate technologies (e.g. Orbisphere) to assist/validate data collection and method development.

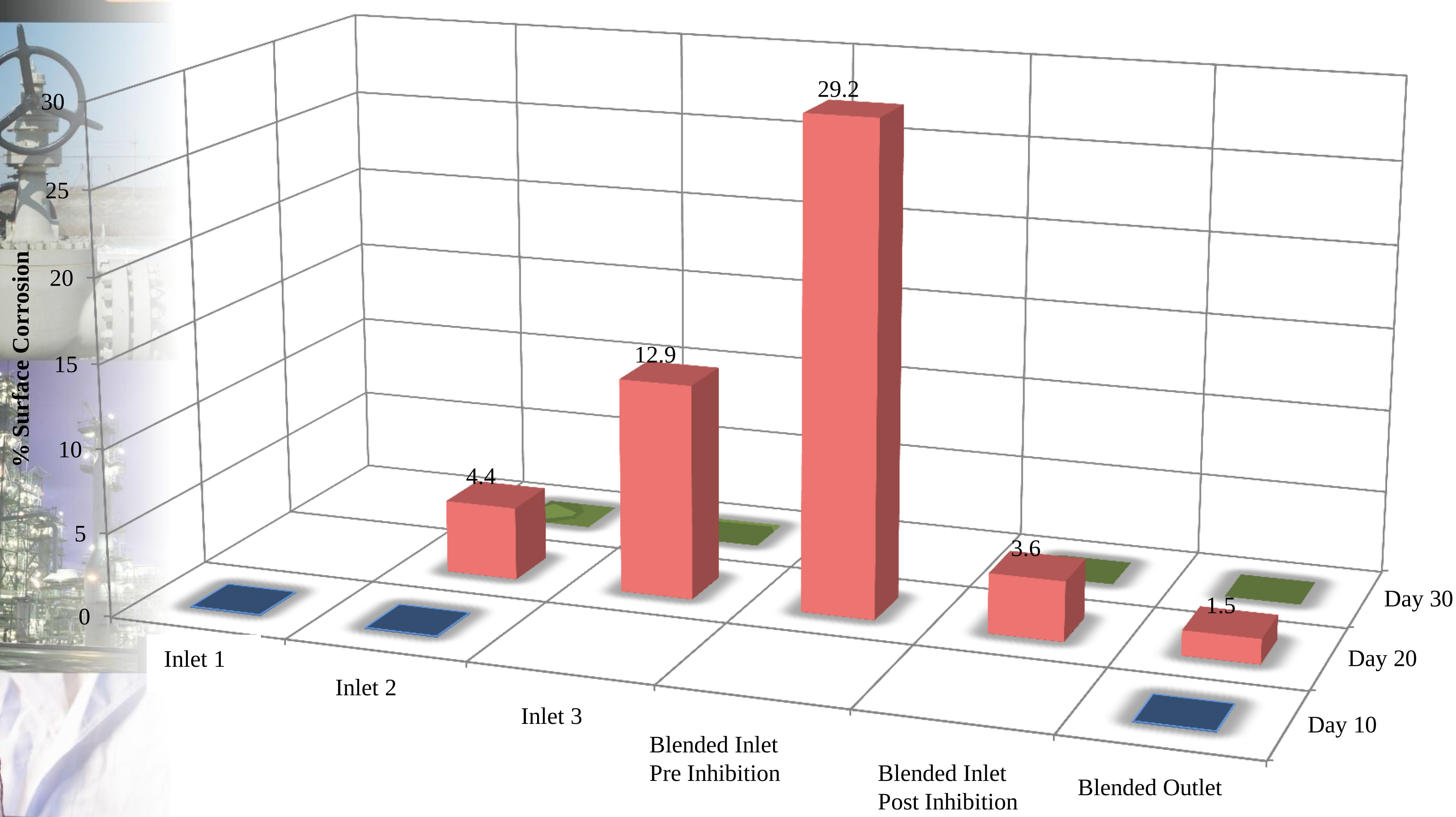
TX Pipeline (API 40+)

Sediment Transmission



Surface Corrosion Test

NACE TM0172(Mod)



Pipeline Corrosion

- Preceding example demonstrates time related corrosion/sediment response to unknown variables
- Based on sediment analysis (majority Fe-O complexes) oxygen is a key parameter
- O_2, H_2S are relevant AND difficult to quantify in stabilized (gas free) TX pipelines
- CO_2 impact in TX pipelines is presently unknown

- Questions?

Sour Service Project - Background

- MR0175 / TM 0177 were created to establish material requirements and test methods for materials is H_2S containing environments
- CAN/CSA Z662 “Oil and Gas Pipeline System” incorporated specific reference to MR0175 since (at least) 1994
- ISO 15156 (2003) no longer excluded ‘transmission pipelines’
- (2007) CSA Z662 dropped specificity to gas and multiphase systems and became applicable to gas-free liquid systems (TX P/Ls)
- (~2011-2013) Industry research revealed that there are no suitable methods for H2S monitoring under normal TX pipeline conditions
- 2014 – lobbying of CSA lead to changes to the code that allowed dissolved H2S monitoring, and grandfathered acceptable conditions

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The Old Code – CSA Z662 07/11

- 16.2.1

  "Sour Service" means

a) for pipeline systems containing a gas phase, service in which the hydrogen sulphide partial pressure exceeds 0.3 kPa at the design absolute pressure; and

b) for pipeline systems not containing a gas phase (gas –free liquid pipeline systems), service in which the effective hydrogen sulphide partial pressure exceed 0.3kPa at the bubble point absolute pressure

Notes:

1. For pipelines systems containing a gas phase, partial pressure can b e determined by multiplying the mole fraction (mol% divided by 100) of hydrogen sulphide in gas by the design pressure.
2. For pipeline systems not containing a gas phase (gas free liquid systems having no separate gas phase at operating conditions but containing gas dissolved in the liquid), the effective hydrogen sulphide partial pressure at the bubble point pressure can be determined by using ANSI/NACE MR0155/ISO 15156-2, Annex C. For a gas-free liquid pipeline downstream of gas separation units, a good approximation of bubble point pressure is the total pressure at the last gas separator. The bubble point pressure is the pressure under which gas bubbles will form in a liquid at a particular operating pressure.
3. While the concentrations given in Items a) and b) are the normally accepted minimum concentrations at which material problems occur, the presence of other constituents in the phases making up the fluid, such as CO2 in the gas

Project work & Findings to Date 2008 - 2011

1. (H2S PVT Project) No suitable techniques for measuring H_2S concentrations at bubble point for stabilized crude oils.
   a) No upstream gas separators to measure vapor phase H_2S
   b) Modeling systems (PVT) are not accurate enough
2. Stabilized Crude oils will not reach bubble point conditions at normal Transmission line operating pressures.
3. No reliable methods for measuring H_2S concentration in dispersed (<0.5%) aqueous phase
4. There is no evidence to suggest that aqueous phases are sufficiently corrosive to support H_2S induced SSC
   1. 70 + years of SSC free operating experience

The New Code - CSA Z662-15

Clause 16.1.2

The following services are excluded from the requirements of this Clause:

a) gas-free pipeline systems for crude oil, crude oil blends, and LVP condensate, with materials with minimum yield strength of 483 MPa or less, containing

   i. less than 0.5 volumes % of basic sediment and water;

   ii. Less than 425 wppm dissolved H_2S, as determined by the ASTM UOP 163 test method; and

   iii. Liquids that are stabilized (i.e., where the bubble point pressure is less than atmospheric pressure);

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Issues with the New Code

- There is ambiguity in the definition of "stabilized"
- 425 wppm dissolved H_2S exclusion was grandfathered based on project testing and operating history
  - No science to support the 425 limit
  - At 425; vapor phase H_2S levels are hazardous (OS&H) and bubble point concentrations could be expected to exceed the 0.3kPa limit; by as much as a factor of 10.

Sour Service Project Group Proposal

- Using TM 0177 and/or TM 0284 to determine conditions under which SSC might occur in transmission lines.
- Step 1 – Confirm Operating History

  Test basic assumptions for tariff quality crudes:

  » pH and H_2S conditions are not severe enough to lead to SSC.

  » Insufficient water (<0.5%) and the pipe wall is expected to be oil wet.

Sour Service Project Group Proposal

- Step 2 – Push the Envelope

  Expand the test envelop conditions to create SSC in transmission lines. Assess the impact of

  » Expanding the pH range.

  » Increasing the H_2S concentrations of the bulk phase.

  » Increasing the water content of crude.

  » Modifying operating conditions (i.e. T, P).

Presentation at NACE C2016

(Presentation to MR0175 maintenance panel)

- Outlined history of the issue, the CCQTA, and proposed the research
- Panel was very interested, and provides much feedback on the importance of demonstrated experimentation
- Several Panel Members offered to participate in project reviews (experimental method), seen as necessary to generate evidence based exclusions to the Sour Service material requirements.

Sour Service Project

- Active Membership (4):
  - Enbridge, TCPL, Kinder Morgan, Inter Pipeline
- Financials:
  - $125K allocated in 2016 for ongoing technology proofing (AITF)
- 2016 Milestone/Targets:
  - Collecting commodity liquid H_2S data (UOP 163)
    - 64 commodities tested – 850 data point collected to date
    - Continue regular testing of commodities until a viable alternative can be presented to regulators
  - Validate test methodology
    - Confirm that selected protocol can measure SSC.
  - Develop test protocol to assess risk of SSC in gas free transmission lines
    - Protocol to be vetted by some MR0175 panel members
  - Begin lab testing (AITF) program