STEM-Corrosion™

Paper Number: 2015-06

Implementation of 50 Key Performance Indicators (KPIs) in Corrosion Control of an Oil Transmission Pipeline

Nafiseh Ebrahimi, M.Sc.
PhD student, Western University, London, ON
Phone: 519-702-4940
Email: nebrhai6@uwo.ca

Abstract

The 5-M methodology: Modeling, Mitigation, Monitoring, Maintenance and Management is an effective tool in controlling and management of corrosion. In this paper the applicability of this tool to assess the corrosion risk in different areas of operation of an oil transmission pipeline is evaluated. This pipeline connects the southwestern Ontario and Montreal. Because of its critical environmental location, proper management of this oil transmission line is of great importance.

50 Key Performance Indicators (KPIs) that are crucial to the successful corrosion control of an asset in the entire service life are identified and are ranked in this paper. A simple colour code is used to show the areas of improvement in this pipeline.

1-Introduction

Transmission pipelines transport crude oil from the production centres to the refineries. Product pipelines distribute the product from the refineries to their regional or municipal networks. The transmission pipelines also deliver natural gas directly to large industrial end-users, including electric generating facilities. The pipeline are usually operated at high pressures and moderate temperatures. The pipelines are generally fabricated from carbon steel. The primary causes of pipeline failures include: metal loss, cracking, external interference, dents and mechanical damage, material, manufacturing or construction and geotechnical threat.

Between all the major failure causes, risk of corrosion is relatively high. Corrosion failures may include stress corrosion cracking (SSC), localized pitting corrosion, microbiologically influenced corrosion (MIC), stray current corrosion, telluric current corrosion and fretting corrosion.

2- Context of Corrosion Control

The pipeline studies in this paper was constructed in 1975 and was placed into service in 1976 to transport Western Canadian condensate, sweet and sour crude oil from Sarnia to Montreal. This pipeline is divided into different segments of 192, 217, 215 and 206 km. The risk of corrosion is high in this pipeline as there are more than 5 mechanisms that can cause corrosion both internally and externally.

3- Internal Corrosion- Model

Although material selection is not based on corrosion consideration, the carbon steel alloy is compatible in the environment with appropriate corrosion control measures.

Smallest thickness of pipe is 6.35 mm which is more than mitigated corrosion rate (0.3mm/yr) times anticipated life of the pipe (Based on NACE RP0102).

Due to the sensitive location of this pipe, the nature of upset conditions is fully understood and the abnormal operations are recorded frequently. The localized pitting corrosion rate was estimated using GRI-00/0230 standards. Internal corrosion rate after maintenance activities is reported to be 0.067 mm/year which is less than corrosion rate before maintenance activities.

4- Internal Corrosion-Mitigation

Mitigation strategies were mainly based on analysis performed at the conceptual and design stages, The internal corrosion mitigation measures include: tariff limits on sediment and water (S&W) content, line cleaning, and chemical inhibition (if required). Available information indicate that the mitigation program is working efficiently.

5- Internal Corrosion-Monitoring

The pipeline is routinely inspected with by inline inspection (ILI) using magnetic flux leakage (MFL) tool. For sections considered to have an elevated susceptibility to internal corrosion, additional monitoring programs are implemented. These additional monitoring programs include coupons, electric resistance Matrices (ERM), and field signature m (FSM).

6- External Corrosion-Mitigation

This underground pipeline is protected by both protective coatings (polyethylene tape (PE)) and cathodic protection from the beginning of operation. To enhance the cathodic protection (CP) monitoring system, remote monitoring equipment was installed on all Eastern region rectifiers in 2011. This facility allows recording of all rectifiers via satellite communications on a weekly basis. This optimization of mitigation strategies (i.e., CP) is insured based on monitoring data.

7- External Corrosion-Model

Based on field operating conditions, the external corrosion rate is reported to be 0.109 mm/yr. Increased temperature due to upset conditions in the upstream segment may accelerate corrosion. However, a very good documentation of all the abnormal operations in this pipeline is kept and analyzed for this impact on corrosion.

8- External Corrosion-Monitoring

The external corrosion control monitoring include: CP current requirement as well as ILI-MFL and ILI-UT inspection. Further sections of pipelines are excavated and repair as required.

9- Measurement

As a standard, all measurement data required for deciding corrosion conditions are available in a readily usable format. The validity of the measured data is established using a standard practice and the measured data is properly integrated to establish the corrosion rate.

10- Maintenance

This pipeline has experienced operating pressures well below maximum operating pressure (MOP). However in some cases the operating conditions has exceeded the normal condition for a short period of time. Pipeline Controller monitors pipeline conditions (such as pipeline pressure), 24/7 through the Supervisory Control and Data Acquisition system (SCADA). The SCADA is designed to identify and raise an alarm in response to unexpected operational changes (For example sudden drop in pressure may indicate a leak). All corrosion control data is collected by National Association of Corrosion Engineers ("NACE") certified technicians. Therefore, all personnel have proper education and formal training to carry out the task.

11- Management

The management system contains 9 main elements:

1. **Leadership commitment and accountability responsibilities:** Leaders are responsible for developing and supporting improved safety performance and a positive safety culture.
2. **Management Review, safety assurance and continuous improvement:** Review of the management system itself, review of performance and KPI's and metrics; effectiveness and status of corrective actions from previous management reviews; results of internal and external audits and assessments results of risk management system/review.
3. **Risk management:** Involves identifying, analyzing and prioritizing risks associated with our assets and operations that could affect people, property or the environment.
4. **Operations controls:** Operating assets within clearly established parameters according to design standards is critical to safe operations.
5. **Management of change:** Management of change is a systematic approach to ensuring proposed changes are assessed for risk, and that change is effectively implemented to achieve targeted results.
6. **Incident management and investigation:** A process for reporting, investigating, analyzing and documenting safety incidents to identify the root causes and contributory factors.
7. **Emergency response:** In the event of an incident, effective emergency response is necessary for the protection of the public, the environment, employees.
8. **Competency, awareness and training:** A process to recruit, hire and orient employees and ensure they possess the required combination of skills, attributes, attitudes and knowledge to effectively and safety perform their roles.
9. **Documentation and recordkeeping**. Effective and accurate documentation is a critical component of safety management, operational reliability, regulatory compliance and risk management. Transformation of the collected data to data base is both automatic and with human intervention.

The management review process includes a review of corrosion control activities and mechanical damage control activities every 2 years.

12- Summary

Table 1 provides detailed evaluation on the application of 50 KPIs in the oil transmission pipeline studied and Fig. 1 provides an overview of the status of implementation of the 50 KPIs. As illustrated in Fig. 1, implementation of most KPIs are good and fair; implementation of a very few KPIs is poor. The overall results of the analysis demonstrate that the oil transmission pipeline studied is in a safe and reliable operating condition.

13- References

1- 1. S. Papavinasam, "Corrosion Control in the Oil and Gas Industry", 1020 pages (October 2013), Gulf Professional Publication (Imprint of Elsevier), ISBN: 978-0-1239-7022-0.

2- Enbridge Pipelines Inc., "Engineering assessment for line 9 reversal phase 1" www.neb-one.gc.ca/L9_Reversal-Phase_l-Engineering_Assessment.pdf

3- S.Papavinasam, "Aim Corrosion Management: Perfect Key Performance Indicators" NACE, NAWC, Calgary, 2015.

4- Enbridge Pipelines Inc., “Line 9B Reversal and Line 9 Capacity Expansion Project“, www.enbridge.com/ECRAI/Line9BReversalProject.aspx
5- Enbridge safety management system framework, www.enbridge.com/AboutEnbridge/Safety/Safety-Management-System-Framework.aspx

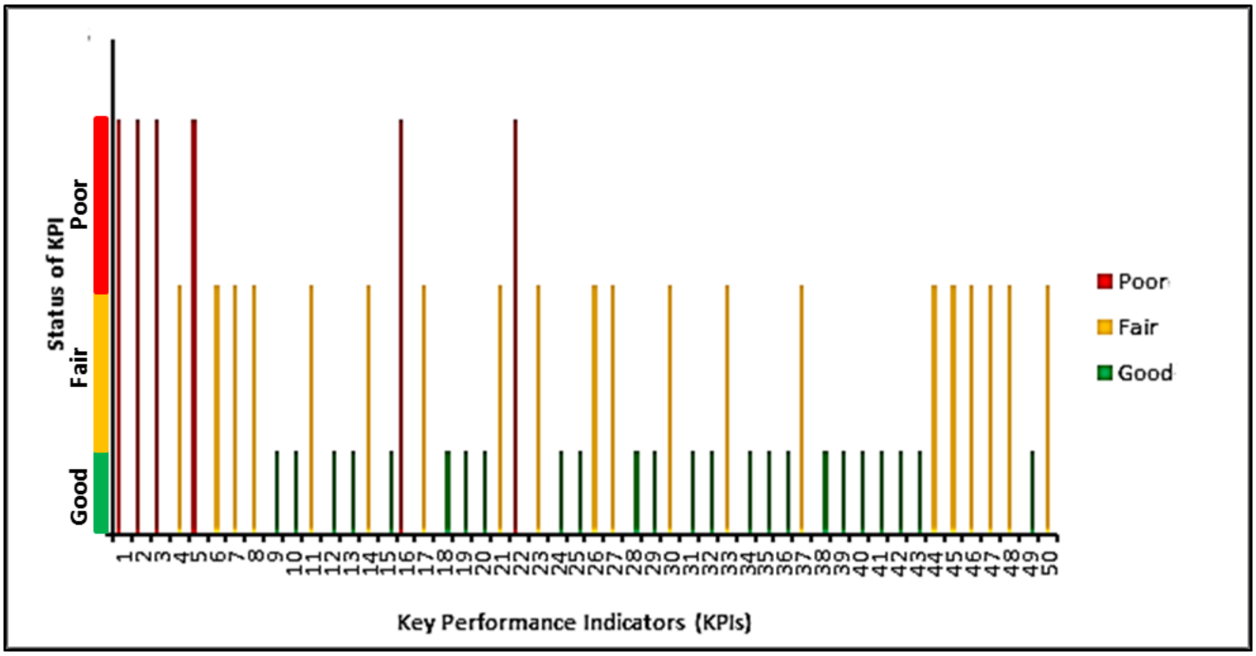

Figure 1, Status of 50 key performance indicators in studied line.

Table 1: Key Performance Indicators (KPIs) to Develop Effective and Economical Corrosion Control Strategies [1]

KPI Number	KPI description	Stages of implementation	Ranking
1	Segmentation of the infrastructure	Conceptual	Poor
2	Corrosion risks	Conceptual	Poor
3	Location of the infrastructure	Conceptual	Poor
4	Overall corrosion risk (Risk times consequence)	Conceptual	Fair
5	Life of the infrastructure	Conceptual	Poor
6	Materials of construction	Design	Fair
7	Corrosion allowance (wall thickness)	Design	Fair
8	Main operating conditions	Design	Fair
9	Potential upset conditions in the upstream sector affecting this sector	Design	Good
10	Potential upset conditions in this sector affecting downstream sector	Design	Good
11	Mechanisms of corrosion	Design	Fair
12	Maximum corrosion rate (Internal)	Design	Good
13	Maximum corrosion rate (External)	Design	Good
14	Installation of proper accessories during construction	Construction	Fair
15	Commissioning	Commission	Good
16	Mitigation to control internal corrosion – is it necessary?	Operation	Poor
17	Mitigation strategies to control internal corrosion	Operation	Fair
18	Mitigated internal corrosion rate, target	Operation	Good
19	Percentage time efficiency of internal corrosion mitigation	Operation	Good
20	Mitigation to control external corrosion – is it necessary?	Operation	Good
21	Mitigation strategies to control external corrosion	Operation	Fair
22	Mitigated external corrosion rate, target	Operation	Poor
23	Percentage time efficiency of external corrosion mitigation strategy	Operation	Fair
24	Internal corrosion monitoring techniques	Operation	Good
25	Number of probes per square area to monitor internal corrosion	Operation	Good
26	Internal corrosion rate, from monitoring technique	Operation	Fair
27	Percentage difference between targeted mitigated internal corrosion rate and corrosion rate from monitoring technique	Operation	Fair
28	External corrosion monitoring techniques	Operation	Good
29	Number of probes per square area to monitor external corrosion	Operation	Good
30	External corrosion rate, from monitoring technique	Operation	Fair
31	Percentage difference between targeted mitigated external corrosion rate and corrosion rate from monitoring technique	Operation	Good
32	Frequency of inspection	Operation	Good

33	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique	Operation	Fair
34	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique	Operation	Good
35	Measurement data availability	Operation	Good
36	Validity and utilisation of measured data	Operation	Good
37	Procedures for establishing the maintenance schedule	Operation	Fair
38	Maintenance activities	Operation	Good
39	Internal corrosion rate, after maintenance activities	Operation	Good
40	Percentage difference between targeted mitigated internal corrosion	Operation	Good
41	External corrosion rate, after maintenance activities	Operation	Good
42	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring or inspection technique and corrosion rate before maintenance activities.	Operation	Good
43	Workforce - Capacity, education, and training	Operation	Good
44	Workforce - Experience, knowledge, and quality	Operation	Fair
45	Data management - Data to database	Operation	Fair
46	Data management - Data from database	Operation	Fair
47	Internal communication strategy	Operation	Fair
48	External communication strategy	Operation	Fair
49	Corrosion management review	Operation	Good
50	Failure frequency	Operation	Fair