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Case Study: Key Performance Indicators implementation in gas transmission pipeline

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Abstract

Corrosion is a major threat that affects many assets of the oil and gas industry. Therefore, it is important to develop and implement good corrosion control strategies. The key performance indicators (KPIs) provide operators an effective tool to track implementation and success of the corrosion control strategies.

Fifty (50) KPIs have been previously identified to track implementation of corrosion control strategies. This paper evaluates the applicability of these 50 KPIs for tracking the implementation of corrosion control strategies in a gas transmission pipeline.

1. Introduction

The gas transmission pipeline used in this case study receives dry natural gas from another transmission line and transports it to several factories and distribution centers all along its path. The pipeline networks includes measurement, odorization and pressure regulation stations to control fluid parameters, to enable detection of gas leakage, and to regulate operating pressure respectively.

This 30-year old pipeline is of 6 inch in diameter, of 80 km in length and has a nominal wall thickness of 5.56 millimeters. It operates at 60 bars of pressure and at 25°C of temperature.

Over the years, the regulations in Argentina have become stringent and, about five years ago, the regulations required that pipeline integrity management system (PIMS) was developed and implemented. To meet this regulation, a qualitative risk assessment was undertaken following ASME B 31.8S[1] and methodology developed by Mulhlbauer[2]. The assessment established third party damages and design (fabrication and construction) as main risks, and internal and external corrosion as secondary risks.

- Third party damage was considered as a main risk because the pipe traverses through populated regions and no records were available to indicate the third parties were educated of the existence of pipeline. Further the pipeline traversed through soil that was prone to soil erosion. Therefore risk due to natural events existed.

- Design (fabrication and construction) related activities were considered as higher risk because no records on hydrostatic test results and on specified minimum yield strength (SMYS) levels were available. Further, the operating pressure of the pipeline was close to maximum allowable operating pressure (MAOP).
- Internal corrosion was not considered as the main risk because the pipeline transported dry natural gas that is free of contaminants. The pipeline, however, was non-piggable. Therefore internal corrosion risk existed.
- External surface of the pipeline was coated and further backed up by cathodic protection. Therefore, external corrosion risk was considered as minimum.

In this paper, the applicability of 50 KPIs[3-4] to implement corrosion control strategies in this gas transmission pipeline is evaluated.

2. Context of Corrosion Control

Corrosion control strategy adopted by the pipeline operator was based on a detailed analysis of the conditions the pipeline is exposed to both internally and externally. For assessing the risk from corrosion, the operator had sub-divided the pipeline into segments as described in NACE ICDA and ECDA methodologies[5-7]. Analysis revealed that the risk from internal and external corrosion was relatively low. But consequence of a failure was high because sections of pipeline traversed through highly populated areas.

- KPIs relevant to the context of corrosion control are: 1, 2, 3, 4, and 5. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipelines analyzed in this paper.

3. Internal corrosion – Model

Model helps to establish probability of internal corrosion and, possibly, to determine internal corrosion rate. KPIs 6, 7, 9, 10, 11, 12, 14, 39, and 40 are used to track application of internal corrosion models. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- The commodity being transported by the pipeline was dry natural gas with no liquid water and with no or minimum amounts of corrosive gases (carbon dioxide and hydrogen sulphide), solids, condensates and other contaminants. The water content and impurities content were below the level allowed by the regulation. Under these conditions, the probability of internal corrosion was very low.
- The pipeline was constructed in carbon steel and corrosion allowance was established based on similar systems. But no record of the anticipated corrosion rate of the pipeline was available.
- Corrosion professionals were not involved during the construction of the pipeline.
- No accessories for mitigation or monitoring internal corrosion were installed.
- Locations where internal corrosion could occur were recently determined using methods prescribed in NACE DG-ICDA document[5].
- Impact of upset conditions in the sector on the downstream sectors and upset conditions of upstream sectors on this sector were understood and communication plans were established to provide information to appropriate persons should upset conditions occur.

4. Internal corrosion – Mitigation

Mitigation strategies are required if the internal corrosion rates are higher. KPIs 16, 17, 18, and 19 are used to track application of mitigation strategies. Tables 1 and 2 present details of the KPIs and the

rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- No internal corrosion mitigation strategy was developed because the probability of internal corrosion to occur was low.
- Operating conditions and fluid composition were routinely monitored as several locations in the pipelines to ensure that they did not change.
- The gas composition was strictly controlled by the upstream operator to meet the regulatory requirements.

5. Internal corrosion – Monitoring

Monitoring techniques are used to determine corrosion rate under the current operating conditions. KPIs 24, 25, 26, 27, 32, and 33 are used to track utilization of monitoring techniques. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- No internal corrosion monitoring plan was developed
- No equipment installed
- No activities to monitor internal corrosion were carried out.
- Direct inspection performed as per ICDA requirement did not reveal any internal corrosion occurrence.

6. External corrosion – Model

Model helps to establish probability of internal corrosion and, possibly, to determine external corrosion rate. KPIs 6, 7, 9, 10, 11, 13, 14, 41, and 42 are used to track application of external corrosion models. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper.

- The entire pipeline was buried below-ground.
- The soil surrounding the external surface was not analyzed in detail in the design stages of the pipeline
- Based on the type of soil, humidity, pH and bacteria content, the soil was considered as moderately corrosive.
- Based on available data upset condition in the segment would not affect downstream segments and upset conditions in the upstream would not affect external corrosion of this segment.

7. External corrosion – Mitigation

Mitigation strategies are required if external corrosion rates are higher. KPIs 20, 21, 22, and 23 are used to track application of mitigation strategies. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- The externally surface of carbon steel pipeline is protected by 2-layer coating and cathodic protection (CP).
- The coating and CP designs were established in the design stage and installed during construction.

8. External corrosion – Monitoring

Monitoring techniques are used to determine corrosion rate under the current operating conditions. KPIs 28, 29, 30, 31, 32, and 34 are used to track utilization of techniques for monitoring external corrosion. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various

categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- On and off potential were measured at fixed locations every three months. Available readings indicated that the CP system was working properly.
- Cathodic protection rectifiers were checked and adjusted every 6 months.
- Close interval survey (CIS) and direct current voltage drop (DCVG) inspections were carried out frequently and the results indicated that the external surface of the pipeline was in good condition.
- Every time the pipe was excavated, coating condition, soil around the pipe and the pipe surface are examined. No significant corrosion was found in any of the under-ground measurements.
- In conjunction with the ICDA, an external corrosion direct assessment (ECDA)[7] was carried out.
- Test stations were properly installed during construction every one kilometer and at cased crossings.
- No pig launcher and receiver to carry out in-line-inspection were installed.

9. Measurement

During operations several other parameters are measured; some of them are related to corrosion. KPIs 35 and 36 are used to track utilization of data from measured properties. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- The pipeline operator developed standards and practices to collect many parameters based on industry best practices. But no proper database to integrate the data was established. The data could only be manually analyzed. For this reason, many important information were missing or could not be used due to errors in matching different data.

10. Maintenance

During operations the pipelines may be serviced and maintained. KPIs 8, 15, 37, 38, 43, 44, 45 and 46 are used to track maintenance activities. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- Maintenance activities were conducted according to a preventive maintenance plan
- A schedule was also available to carry out maintenance activities based on inspection or monitoring data. The maintenance was generally carried as per the schedule, with some minor exceptions.
- The number of workers involved in corrosion control of the pipeline were enough, but none of them had corrosion education or training
- Field inspection or maintenance activities were mostly carried out by third parties.

11. Management

Establishing appropriate management system is essential for coordination of many corrosion control activities. KPIs 47, 48, 49, and 50 are used to track management activities. Tables 1 and 2 present details of the KPIs and the rationale for ranking KPIs in various categories with respect to the gas transmission pipeline analyzed in this paper. The following aspects were considered in ranking KPIs:

- The pipeline operator has developed a good plan for communications with regulator public, and landowners and among various groups within the company. However documented evidence that the all communication plan were executed was not available.
- The corrosion control related data were not reviewed periodically, except for the cathodic protection results.

- No failures have occurred due to corrosion for the entire 20 years of operating the pipeline.

12. Status of KPIs and Status of infrastructure

Figure 1 presents the status of the KPIs implementation in the pipeline of interest. The green color bar indicates successful implementation of the strategy, yellow color bar indicates inadequate implementation of the strategy, and red color bar indicates poor or non- implementation of the strategy.

13. Recommendations

It is obvious from Figure 1 that implementation of most KPIs are good and that opportunities to improve their corrosion control strategies exist. Some are discussed in the following paragraphs:

- Develop a corrosion management plan (KPI 49): Periodically review data from corrosion control strategies.

- Install monitoring devices (KPIs 24, 25, 26, 27, 39, 40, 41, and 42): Implementation of monitoring devices and monitoring corrosion rates will increase the confidence that the pipeline is continued to be safe.

- Develop a corrosion database (KPIs 45 and 46): Establishment of user-friendly database will facilitate easier and fast access of data and enable quick decision making.

14. Conclusions

- This paper has analyzed implementation of KPIs to control corrosion in a gas transmission pipeline.
- The risk from corrosion in this gas transmission pipeline is low.
- Many KPIs have been implemented but opportunities exist to implement other KPIs. Implementation of additional KPIs will further decrease the risk from corrosion.
- Additional KPIs that would further decrease corrosion risk to the gas transmission pipeline has been recommended.

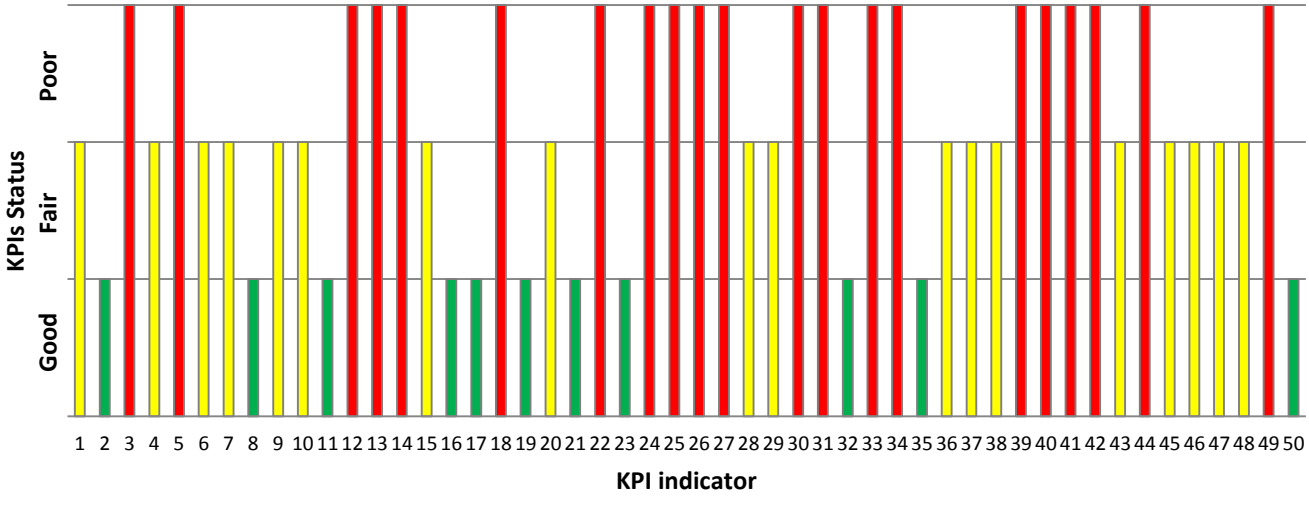

Figure 1: Key Performance Indicators evaluation results

Table 1: KPI description and ranking

KPI No.	KPI description	Ranking	Remarks
1	Segmentation of the infrastructure	Fair	Segmentation was done according to NACE ECDA and DG-ICDA. Segments are of different in size and are of several km in length
2	Corrosion risks	Good	Low corrosion risk
3	Location of the infrastructure	Poor	The pipeline was in high consequence area and transports highly flammable product
4	Overall corrosion risk (Risk times consequence)	Fair	Overall risk of corrosion is medium
5	Life of the infrastructure	Poor	Operated beyond its designed life.
6	Materials of construction	Fair	Carbon steel is appropriate for this service
7	Corrosion allowance (wall thickness)	Fair	The corrosion allowance was established in the design base on similar operations.
8	Main operating conditions	Good	Operating conditions were maintained within the range established during design
9	Potential upset conditions in the upstream sector affecting this sector	Fair	Upset conditions would influence in internal corrosion, but not external corrosion. Communication plan has been established to provide information in case of an upset.
10	Potential upset conditions in this sector affecting downstream sector	Fair	Upset conditions would influence in internal corrosion, but not external corrosion. Communication plan has been established to provide information in case of an upset.
11	Mechanisms of corrosion	Good	All corrosion mechanisms where evaluated and the most probable once identified.
12	Maximum corrosion rate (Internal)	Poor	Not established.
13	Maximum corrosion rate (External)	Poor	Not established.
14	Installation of proper accessories during construction	Poor	The pipeline had no pig launcher and receiver facilities, no inhibitor injection points, no sample collecting points, and no coupons/probes insertion points. But CP application facilities and CP test points were installed during construction.
15	Commissioning	Fair	No documented report on hydrostatic test and cleaning procedure. But baseline corrosion conditions qualitatively and mitigation strategies defined.
16	Mitigation to control internal corrosion – is it necessary?	Good	No, because the pipe transports dry natural gas containing low amounts of corrosive gases and water (below levels required by regulations.
17	Mitigation strategies to control internal corrosion	Good	Not needed
18	Mitigated internal corrosion rate,	Poor	Not established.

	target		
19	Percentage time efficiency of internal corrosion mitigation strategy	Good	Not relevant.
20	Mitigation to control external corrosion – is it necessary?	Fair	Yes.
21	Mitigation strategies to control external corrosion	Good	Coatings applied and CP installed during construction.
22	Mitigated external corrosion rate, target	Poor	Not established.
23	Percentage time efficiency of external corrosion mitigation strategy	Good	CP worked properly for the entire duration of operation of the pipeline.
24	Internal corrosion monitoring techniques	Poor	None.
25	Number of probes per square area to monitor internal corrosion	Poor	None.
26	Internal corrosion rate, from monitoring technique	Poor	None.
27	Percentage difference between targeted mitigated internal corrosion rate and corrosion rate from monitoring technique	Poor	Not applicable.
28	External corrosion monitoring techniques	Fair	CP potential on test points, close-interval service (CIS) and direct current voltage gradient (DCVG). No coupons or probes installed.
29	Number of probes per square area to monitor external corrosion	Fair	Enough to cover most critical areas.
30	External corrosion rate, from monitoring technique	Poor	No corrosion rate monitoring techniques used. CIS data revealed the potential was more negative than -850 mV off vs copper-copper sulphate (CCS) reference electrode over 99% of the pipeline.
31	Percentage difference between targeted mitigated external corrosion rate and corrosion rate from monitoring technique	Poor	Not established.
32	Frequency of inspection	Good	Established based on risk analysis and regulation
33	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique	Poor	No internal corrosion monitoring performed.
34	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring techniques and corrosion rate from inspection technique	Poor	No internal corrosion monitoring performed.

35	Measurement data availability	Good	All data collected was available in a readily usable format, but not all data required was collected.
36	Validity and utilization of measured data	Fair	Data were validated using standard or recommended practices, but no process was established to integrate and determine corrosion rate. Further, no database was available to integrate data.
37	Procedures for establishing the maintenance schedule	Fair	Preventive maintenance to keep the risk below as low as reasonably possible (ALARP) level was established based on results from inspection and monitoring.
38	Maintenance activities	Fair	Generally carried out on time
39	Internal corrosion rate, after maintenance activities	Poor	Not established.
40	Percentage difference between targeted mitigated internal corrosion rate or corrosion rate from monitoring or inspection technique (whichever is decided in activity 27) and corrosion rate before maintenance activities.	Poor	No internal corrosion monitoring performed.
41	External corrosion rate, after maintenance activities	Poor	Not established.
42	Percentage difference between targeted mitigated external corrosion rate or corrosion rate from monitoring or inspection technique and corrosion rate before maintenance activities.	Poor	No external corrosion monitoring performed.
43	Workforce - Capacity, education, and training	Fair	Number of people just enough. Many activities were carried out by third party company personnel.
44	Workforce - Experience, knowledge, and quality	Fair	Personnel has extensive experience knowledge on pipeline integrity but not enough on corrosion control.
45	Data management - Data to database	Fair	Data were collected and stored properly.
46	Data management - Data from database	Fair	Information was available in the database but they were not property integrated.
47	Internal communication strategy	Fair	A communication strategy was established but were not practiced appropriately.
48	External communication strategy	Fair	A communication strategy was established but were not practiced appropriately.
49	Corrosion management review	Poor	CP information was reviewed and improved once a year. There was no scheduled review on other corrosion control strategies
50	Failure frequency	Good	No failure due to corrosion over the past 20 years of operation.

Table 2: KPIs results by category

Category	Stage of implementation	KPI identification*	Numbers (Percentage)		
			Good	Fair	Poor
Context of Corrosion Control	Conceptual	1, 2, 3, 4, 5	1 (20)	2 (40)	2 (40)
Model (Internal corrosion)	Design / Commissioning / Operation	6, 7, 9, 10, 11, 12, 14, 39, 40	1 (11)	4 (44.5)	4 (44.5)
Mitigation (Internal corrosion)	Operation	16, 17, 18, 19	3 (75)	-	1 (25)
Monitoring (Internal corrosion)	Operation	24, 25, 26, 27, 32, 33	1 (17)	-	5 (83)
Model (External corrosion)	Design / Commissioning / Operation	6, 7, 9, 10, 11, 13, 14, 41, 42	1 (11)	4 (44)	4 (44)
Mitigation (External corrosion)	Operation	20, 21, 22, 23	2 (50)	1 (25)	1 (25)
Monitoring (External corrosion)	Operation	28, 29, 30, 31, 32, 34	2 (33)	1 (17)	3 (50)
	Operation	35, 36	1 (50)	1 (50)	-
Maintenance	Operation	8, 15, 37, 38, 43, 44, 45, 46	1 (12.5)	6 (75)	1 (12.5)
Management	Operation	47, 48, 49, 50	1 (25)	2 (50)	1 (25)

*Some KPIs are included in more than one category. The most conservative result was considered in Table 1.

15. References

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