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Risk-Based Integrity Evaluation of Hydrocarbon and Utility Piping Systems Using Corrosion Rate, Remaining Life, and Inspection Data: A Quantitative Case Study

Edy Karina [1,*], Yudha Pratesa [1], Johny Wahyuadi Mudaryoto [1]

[1] Department of Metallurgical and Materials Engineering, Faculty of Engineering, Universitas Indonesia, Depok 16424, Indonesia
* Correspondence: edykariina@gmail.com

Abstract: Hydrocarbon and utility piping systems are critical assets in oil and gas facilities because they support fluid transfer under pressure, temperature variation, and corrosive service conditions. Failure of these systems can cause leakage, production disruption, safety hazards, environmental impact, and repair cost escalation. This study develops a risk-based integrity evaluation framework for piping systems by integrating corrosion rate assessment, remaining life estimation, Probability of Failure, Consequence of Failure, risk ranking, and Risk-Based Inspection prioritization within an Asset Integrity Management context. A quantitative case study was conducted using 2025 industrial inspection data from 82 piping lines grouped into Atmospheric Drains, Flare Line, Hydrocarbon Liquid, Utility Water, Produced Water, and Hydrocarbon Gas systems. The assessment used ultrasonic thickness measurement, actual wall thickness, required minimum thickness, corrosion rate, remaining life, PoF-CoF classification, risk category, and inspection planning year. The results show that 80 piping lines were categorized as Very Low Risk, 1 Utility Water line was categorized as Low Risk, and 1 Hydrocarbon Gas line was categorized as Medium Risk. Utility Water recorded the highest corrosion rate of 0.253 mmpy and the shortest remaining life of 8 years, indicating the highest degradation concern in the evaluated dataset. Hydrocarbon Gas recorded a corrosion rate of 0.076 mmpy and a remaining life of 38 years, but remained in the Medium Risk category due to its consequence profile. The proposed framework supports inspection prioritization, mitigation planning, and risk-informed maintenance decisions within an Asset Integrity Management context.

Keywords: Asset Integrity Management; corrosion assessment; hydrocarbon piping; remaining life; Risk-Based Inspection; risk ranking

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1. Introduction

Piping systems are essential components in oil and gas facilities because they transfer hydrocarbon, water, flare, and utility fluids between process equipment. These systems operate under different pressure, temperature, fluid, and environmental conditions. Their integrity affects process safety, production continuity, environmental protection, and maintenance cost control [1], [2], [3]. Failure of piping systems can lead to loss of containment, shutdown, fire, explosion, environmental release, and unplanned repair activities [3], [4], [5].

Material degradation in piping systems can occur through internal corrosion, external corrosion, wall thinning, pitting, erosion-corrosion, corrosion under insulation, and localized degradation [6], [7], [8]. Corrosion remains one of the most important degradation mechanisms because it reduces wall thickness progressively and can remain undetected without proper inspection coverage [6], [8], [25]. Therefore, piping integrity evaluation should not rely only on current thickness data. It must also consider corrosion rate, remaining life, degradation tendency, failure likelihood, failure consequence, and inspection effectiveness [13], [14], [15].

Asset Integrity Management provides a structured approach to ensure that assets remain safe, reliable, and fit for service throughout their operating life [9], [10]. AIM connects inspection, maintenance, operating control, risk assessment, degradation management, and mitigation planning [9], [10], [12]. Within this framework, Risk-Based Inspection supports inspection decision-making by prioritizing inspection based on risk rather than fixed inspection intervals [11], [13], [14]. RBI combines Probability of Failure and Consequence of Failure to determine risk level, inspection priority, and mitigation strategy [14], [15], [29].

Previous studies have shown that RBI can improve inspection planning, optimize inspection intervals, support risk-based maintenance, and strengthen pipeline integrity management [3], [4], [5], [13]. Li et al. [16] developed a risk-based maintenance decision model for subsea pipelines subject to pitting corrosion. Campari et al. [17] showed that machine learning can support risk-based inspection strategies for hydrogen handling equipment. Other studies have discussed dynamic risk assessment, safety barrier management, FMEA-MCDA risk management, digital twin application, corrosion defect prediction, and data-driven remaining useful life estimation [18], [19], [20], [21], [22], [23].

However, many prior studies still discuss corrosion evaluation, remaining life estimation, risk ranking, and AIM decision support as separate subjects [9], [13], [16], [23]. Limited studies present a traceable case-based framework that links actual inspection data with PoF-CoF classification, risk category, and inspection planning. This gap is important because operators need practical methods that can translate inspection findings into inspection priority and mitigation planning [10], [11], [12].

Therefore, this study develops a risk-based integrity evaluation framework for hydrocarbon and utility piping systems using a quantitative case study based on 2025 inspection data. The framework integrates corrosion rate analysis, remaining life estimation, PoF-CoF classification, risk ranking, and inspection planning. The contribution of this study is a practical and traceable engineering framework that supports inspection prioritization and mitigation planning within an AIM context [9], [10], [14], [15].

2. Materials and Experiment Methods

This study used a quantitative case study approach to evaluate the integrity condition of hydrocarbon piping systems through an RBI framework. The approach was selected because the analysis used numerical inspection parameters, including ultrasonic thickness measurement, corrosion rate, remaining life, PoF, CoF, and risk ranking. The case study used industrial inspection data from hydrocarbon and utility piping systems operated by PT X during the 2025 integrity inspection program. The methodological design integrated corrosion assessment, remaining life estimation, and risk evaluation within an AIM perspective, as illustrated in Figure 1.

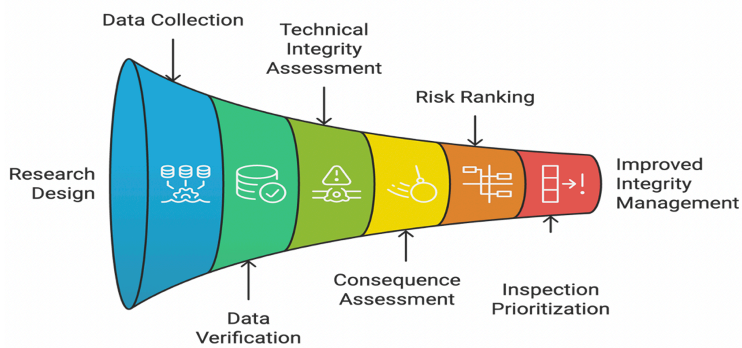

Figure 1. Risk-based inspection methodology.

2.1. Research Framework

This study used a quantitative case study approach. The research was designed as an applied integrity evaluation and framework-development study, not as a literature review. This position is important because the analysis used actual industrial inspection data, numerical corrosion rate values, remaining life values, risk categories, and inspection planning results [14], [15].

The quantitative approach was selected because the study evaluated measurable inspection parameters, including ultrasonic thickness measurement, actual wall thickness, minimum required thickness, corrosion rate, remaining life, PoF category, CoF category, risk ranking, and inspection planning year [24], [26], [29]. This workflow is shown in Figure 2.

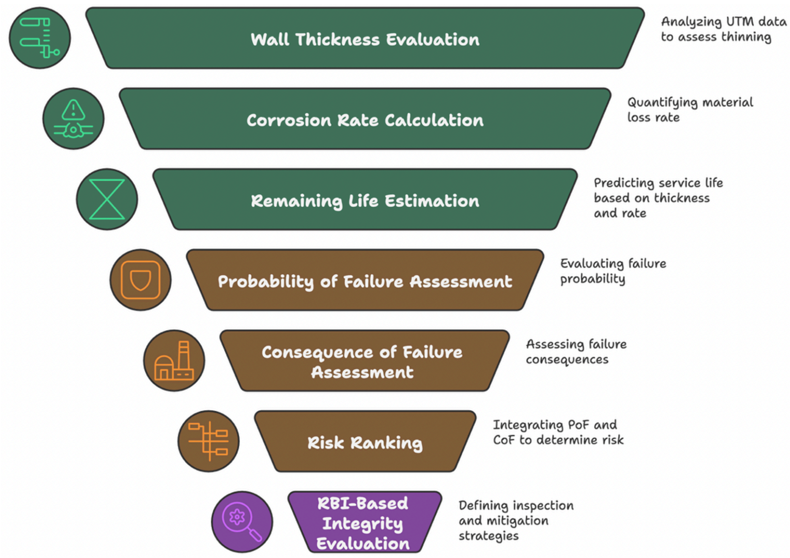

Figure 2. Integrity evaluation workflow based on inspection and risk assessment stages.

The first stage collected technical and operational data, including piping specifications, material types, pipe dimensions, operating pressure and temperature, fluid characteristics, inspection history, ultrasonic thickness measurement data, and operational exposure [24], [26], [28]. The second stage evaluated wall thickness to identify the minimum measured thickness, wall thinning, and degradation tendency in each piping segment [24], [26]. The third stage calculated the corrosion rate to quantify material loss during service [6], [7], [25]. The fourth stage estimated the remaining life by comparing the actual wall thickness, minimum required wall thickness, and corrosion rate [15], [27], [29]. The fifth and sixth stages assessed PoF and CoF [14], [15]. The seventh stage integrated PoF and CoF into an RBI risk matrix. The final stage translated the risk category into inspection priority, inspection interval, and mitigation strategy [11], [13], [14].

2.2. Data Collection and Inspection Parameters

The data were obtained from the 2025 Risk-Based Inspection program of PT X. The selected study scope consisted of 82 evaluated piping lines grouped into six service systems: Atmospheric Drains, Flare Line, Hydrocarbon Liquid, Utility Water, Produced Water, and Hydrocarbon Gas. The RBI executive summary reports that the piping integrity condition was generally acceptable because actual wall thickness was greater than required thickness, MAWP was greater than design pressure, and operating pressure remained below design pressure and MAWP.

The evaluated systems consisted of 13 Atmospheric Drain lines, 36 Flare Lines, 1 Hydrocarbon Liquid line, 15 Utility Water lines, 16 Produced Water lines, and 1

Hydrocarbon Gas line. These systems were selected because they represent different fluid characteristics, consequence profiles, corrosion exposure, and inspection priorities.

2.3. Risk-Based Inspection Procedure

The RBI evaluation followed the principles of API RP 580 and API RP 581. These standards provide a structured method for defining inspection priorities based on risk rather than fixed intervals. In this study, RBI combined system identification, damage mechanism evaluation, inspection effectiveness review, PoF assessment, CoF assessment, risk determination, risk-based inspection planning, and reassessment, as presented in Figure 3.

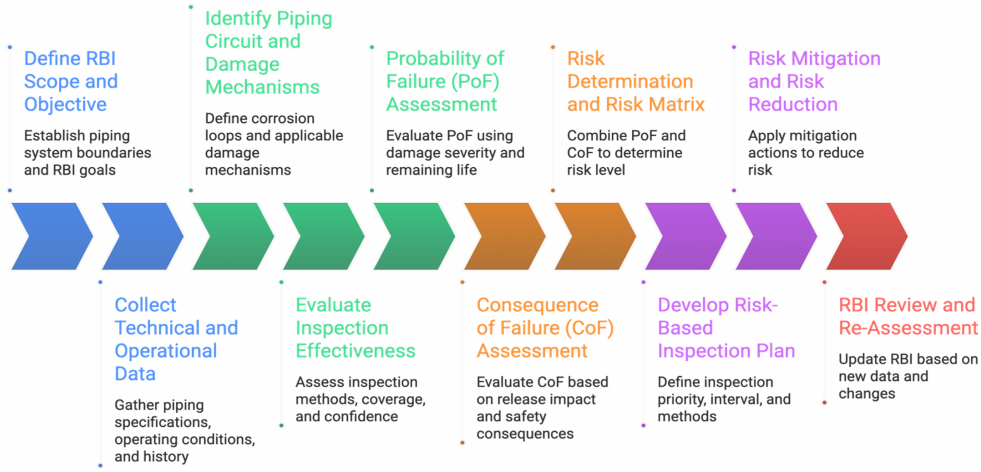

Figure 3. Risk-based inspection workflow procedure.

The procedure began with piping system identification, including material specification, pipe dimensions, operating conditions, fluid characteristics, inspection history, and possible damage mechanisms. Each piping system was classified according to service condition and corrosion susceptibility. Potential degradation mechanisms were then evaluated, with a focus on internal corrosion, external corrosion, wall thinning, pitting corrosion, and localized degradation associated with hydrocarbon and utility water service. PoF was evaluated based on corrosion severity, wall thinning progression, remaining wall thickness, and inspection effectiveness. CoF was evaluated based on hydrocarbon release, safety impact, environmental contamination, operational shutdown, repair cost, and production loss. The PoF and CoF results were integrated into a risk matrix to determine risk category and inspection priority.

2.4. Corrosion Rate Analysis

Corrosion rate analysis was conducted to determine the rate of wall thickness reduction during operation. The corrosion rate was calculated from the difference between the initial wall thickness and the actual measured wall thickness over the service period [40].

$$CR = (t\_initial - t\_actual) / T \quad (1)$$

where CR is the corrosion rate in mmpy, t_initial is the initial wall thickness in mm, t_actual is the actual measured wall thickness in mm, and T is the operating exposure time in years. A higher corrosion rate indicates faster material loss and greater vulnerability to wall thinning. In this study, the corrosion rate was used as an input for remaining life estimation and PoF evaluation.

2.5. Remaining Life Estimation

Remaining life estimation was conducted to predict the remaining operating period before the wall thickness reaches the minimum required limit. This parameter supports inspection urgency, maintenance planning, and repair or replacement priority. The remaining life was calculated using Equation (2).

$$RL = (t\_actual - t\_required) / CR \quad (2)$$

where RL is the remaining life in years, t_actual is the actual measured wall thickness in mm, t_required is the minimum required wall thickness in mm, and CR is the corrosion rate in mm/year. A lower remaining life indicates the need for closer monitoring and shorter inspection intervals. A longer remaining life indicates that the piping system still has a sufficient wall thickness margin for continued operation under controlled conditions.

2.6. Risk Analysis

Risk analysis was performed by integrating PoF and CoF to determine the overall risk level of each piping system. The general risk relationship used in this study is shown in Equation (3) .

$$Risk = PoF \times CoF \quad (3)$$

PoF represents the likelihood of piping failure due to corrosion, wall thinning, and localized degradation. CoF represents the consequence that may occur if piping failure takes place, including safety impact, environmental consequence, hydrocarbon release potential, production loss, operational shutdown, repair cost, and fire or explosion hazard. The integration of PoF and CoF produced the final risk category, which was used to determine inspection priority and mitigation strategy.

2.7. Data Analysis, Validity, and Reliability

The data were analyzed using a descriptive quantitative approach. The analysis identified the relationship between corrosion rate, remaining life, and risk category [13], [16], [23]. Spreadsheet-based calculations were used to process inspection data, calculate corrosion rate, estimate remaining life, and summarize risk categories. The outputs were interpreted using RBI principles and AIM concepts to support integrity-based decision-making [9], [10], [14], [15].

The validity of the analysis was strengthened by using API RP 580 and API RP 581 as the main references for RBI evaluation [14], [15], [29]. The analysis was also supported by API 570 for in-service piping inspection, API 571 for damage mechanism evaluation, API 574 for piping component inspection practice, API 579-1/ASME FFS-1 for fitness-for-service consideration, and ASME B31.3 for process piping requirements [24], [25], [26], [27], [28]. The reliability of the analysis was supported through consistency checks between thickness measurement records, operating data, and inspection documentation.

Multiple measurement points were used to reduce uncertainty and improve the representativeness of the wall thickness evaluation [24], [26]. The integration of corrosion rate, remaining life, and risk ranking improved the robustness of the assessment because piping integrity was evaluated from degradation severity, remaining serviceability, and operational consequence, not from a single parameter [13], [16], [23].

3. Results and Discussion

3.1. Corrosion Analysis

A total of 82 piping lines were evaluated in this study. The evaluated lines consisted of 13 Atmospheric Drains, 36 Flare Lines, 1 Hydrocarbon Liquid line, 15 Utility Water lines, 16 Produce Water lines, and 1 Hydrocarbon Gas line. This directly answers the reviewer's concern that the previous manuscript did not state the total number of evaluated piping systems.

The results show that the overall piping integrity condition remained acceptable. The actual wall thickness was still higher than the required minimum thickness, MAWP was higher than design pressure, and operating pressure remained below design pressure and MAWP. This indicates that the evaluated piping systems were still fit for continued operation under the assessed operating conditions.

Table1. Summary of corrosion rate, remaining life, PoF, CoF, risk category, and inspection planning of evaluated piping systems.

No.	Piping System	Number of Evaluated Lines	Max. Corr. Rate (mmpy)	Critical Tag for CR	Lowest Remaining Life (years)	Critical Tag for RL	PoF Cat.	CoF Cat.	Risk Category Distribution	Next Inspection Plan
1	Atmospheric Drains	13	0.043	1"-DA-0373-1B	23	1"-DA-0373-1B	Very Low	Low	13 Very Low Risk	2033
2	Flare Line	36	0.140	3"-FL-0447-1B	29	3"-FL-0477-1B	Very Low	Low	36 Very Low Risk	2033
3	Hydrocarbon Liquid	1	0.040	4"-HL-1124-1B	31	4"-HL-1124-1B	Very Low	Moderate	1 Very Low Risk	2033
4	Utility Water	15	0.253	2"-UW-0224-1W	8	2"-UW-0224-1W	Very Low to High	Insignificant	14 Very Low Risk, 1 Low Risk	14 lines in 2033, 1 line in 2029
5	Produce Water	16	0.116	2"-WW-0310-6B	29	2"-WW-0310-6B	Very Low	Insignificant to Minor	16 Very Low Risk	2033
6	Hydrocarbon Gas	1	0.076	6"-HG-1132-6D	38	6"-HG-1132-6D	Low	Moderate	1 Medium Risk	2033

The maximum corrosion rate values in Table 1 were obtained from the RBI executive summary. The highest corrosion rate was recorded in Utility Water at 0.253 mmpy, followed by Flare Line at 0.140 mmpy, Produce Water at 0.116 mmpy, Hydrocarbon Gas at 0.076 mmpy, Atmospheric Drains at 0.043 mmpy, and Hydrocarbon Liquid at 0.040 mmpy.

The lowest remaining life values were also taken from the same RBI dataset. Utility Water had the lowest remaining life of 8 years, Atmospheric Drains had 23 years, Flare Line had 29 years, Produce Water had 29 years, Hydrocarbon Liquid had 31 years, and Hydrocarbon Gas had 38 years.

As shown in Figure 4, corrosion assessment should not rely only on periodic thickness measurement because wall thickness data alone may not explain the operational factors that accelerate degradation. A more reliable integrity evaluation requires the integration of corrosion rate, service environment, process condition, degradation mechanism, and risk exposure within the RBI framework. From an AIM perspective, the high corrosion rate in Utility Water Piping indicates the need for stronger mitigation actions, including improved water treatment, corrosion inhibitor optimization, chemical control, internal coating evaluation, and intensive corrosion monitoring [4,6,7].

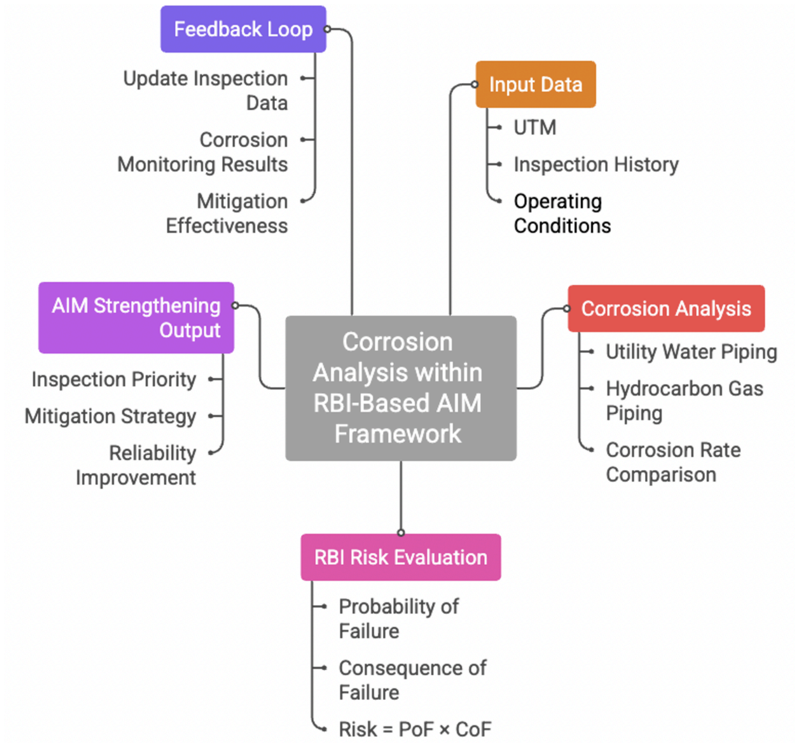

Figure 4. Corrosion analysis within the RBI-based AIM framework.

3.2. Remaining Life Analysis

The corrosion assessment shows that Utility Water had the highest corrosion rate at 0.253 mmpy. This result indicates that Utility Water was the most degradation-sensitive system in the evaluated dataset. The higher corrosion rate can be associated with continuous water exposure, dissolved oxygen, possible chloride contamination, deposit formation, and flow-related corrosion effects. Flare Line recorded the second highest corrosion rate at 0.140 mmpy. Produce Water recorded 0.116 mmpy. Hydrocarbon Gas recorded 0.076 mmpy, while Atmospheric Drains and Hydrocarbon Liquid recorded lower corrosion rates of 0.043 mmpy and 0.040 mmpy. This variation confirms that service fluid and operating environment strongly influence corrosion behavior.

The result also shows that corrosion rate alone should not be used as the only basis for inspection priority. Utility Water had the highest corrosion rate and shortest remaining life, but Hydrocarbon Gas remained in the Medium Risk category because consequence also affects final risk ranking. Therefore, inspection prioritization should combine corrosion rate, remaining life, PoF, CoF, and risk category. The lower remaining life of Utility Water Piping reflects the cumulative effect of wall thinning caused by prolonged exposure to corrosive water service. As actual wall thickness approaches the minimum allowable thickness, the system becomes more vulnerable to leakage, pressure containment loss, and unplanned operational disruption. Therefore, piping systems with shorter remaining life should receive higher inspection priority, closer monitoring, and stronger mitigation actions. Figure 5 summarizes the relationship between corrosion rate and remaining life across the evaluated piping systems.

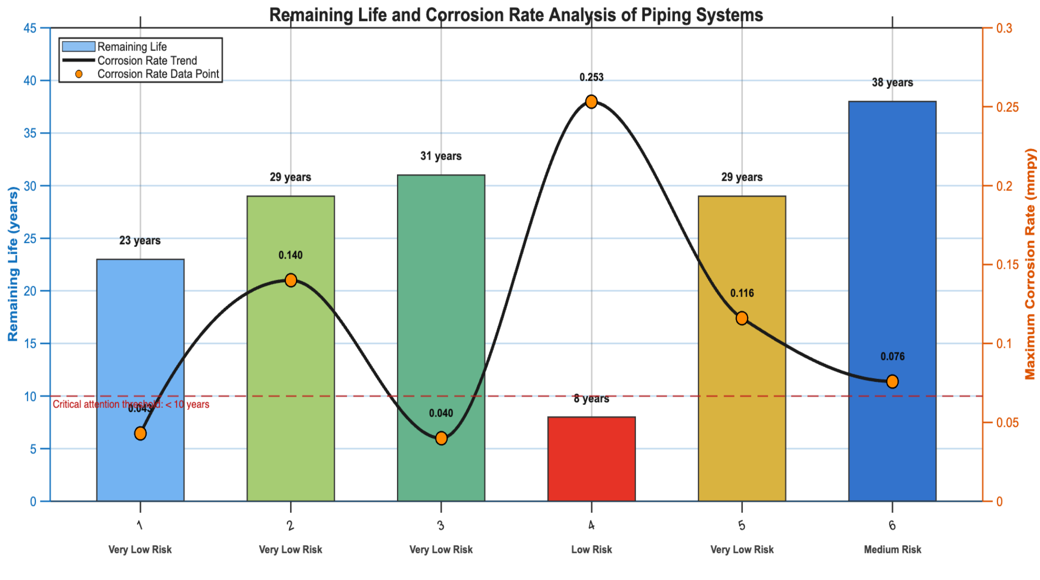

Figure 5. Remaining life and corrosion rate analysis.

3.3. Risk Ranking Analysis

Remaining life evaluation confirms that Utility Water had the highest inspection concern. The lowest remaining life in Utility Water was 8 years. This value was much shorter than Atmospheric Drains at 23 years, Flare Line at 29 years, Produce Water at 29 years, Hydrocarbon Liquid at 31 years, and Hydrocarbon Gas at 38 years. A shorter remaining life indicates that the wall thickness margin is closer to the required minimum thickness. Although the Utility Water system was still acceptable for operation, the 8-year remaining life supports closer monitoring and an earlier inspection plan for the affected line.

Hydrocarbon Gas had a longer remaining life of 38 years, indicating lower wall thinning severity under the evaluated condition. However, it was still categorized as Medium Risk because the consequence profile of hydrocarbon gas service is higher than utility water service. This finding shows that remaining life must be interpreted together with consequence.

Integrating risk ranking into the RBI framework strengthens inspection decision-making by directing inspection resources toward piping systems with the highest degradation severity and operational consequence. Compared with conventional inspection methods that apply uniform intervals, RBI provides a more selective, risk-informed, and technically justified inspection strategy. From an engineering and AIM perspective, Medium Risk systems have not reached critical failure conditions, but their degradation tendency requires stronger control measures, including advanced ultrasonic testing, corrosion mapping, online corrosion monitoring, periodic operating condition review, and targeted mitigation planning [13,18,].

The risk mapping results show that 80 of 82 evaluated piping lines were categorized as Very Low Risk, 1 Utility Water line was categorized as Low Risk, and 1 Hydrocarbon Gas line was categorized as Medium Risk. This revises the previous manuscript statement that "several lines remained in the Medium Risk category." The corrected result shows that only one line was categorized as Medium Risk. Atmospheric Drains, Flare Line, Hydrocarbon Liquid, and Produce Water were fully categorized as Very Low Risk. Utility Water consisted of 14 Very Low Risk lines and 1 Low Risk line. Hydrocarbon Gas consisted of 1 Medium Risk line. This distribution indicates that most evaluated piping lines were in acceptable integrity condition, but selected systems still required different inspection priorities.

The Utility Water line assigned to the Low Risk category requires closer attention because the Utility Water system recorded the highest corrosion rate and shortest remaining life. The Hydrocarbon Gas line requires attention because hydrocarbon gas service has a higher consequence profile, even though its corrosion rate and remaining life were not the most critical.

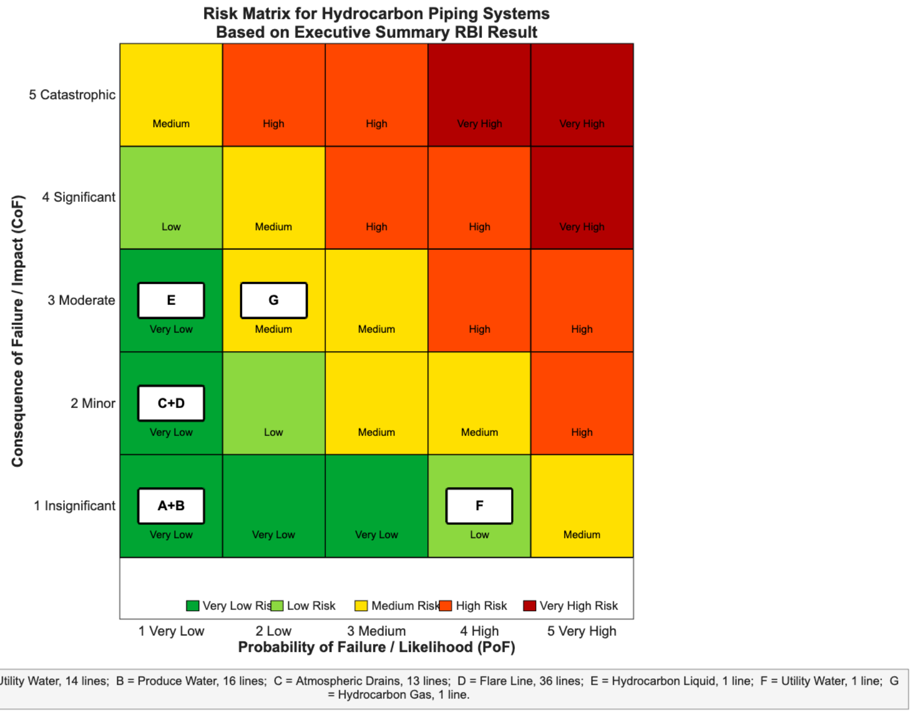

Figure 6. Risk ranking matrix for hydrocarbon piping systems.

3.4. RBI Evaluation

The implementation of RBI provides a clearer and more defensible basis for inspection prioritization, integrity evaluation, and operational decision-making than conventional time-based inspection. In this study, RBI integrates corrosion rate, remaining life, PoF, and CoF into a single risk evaluation framework. This allows inspection planning to reflect actual degradation conditions and operational consequences for each piping system. Conventional inspection methods often apply fixed intervals without fully considering equipment condition, corrosion severity, remaining wall thickness, or failure consequence. This practice can produce inefficient inspection activities because low-risk systems may be inspected too frequently, while systems with higher degradation potential may not receive sufficient attention.

By contrast, RBI enables inspection resources to be focused on systems with higher risk exposure, particularly Medium Risk systems. This approach improves inspection effectiveness, reduces unnecessary maintenance activities, lowers the possibility of unexpected shutdowns, and supports reliability-centered asset management. These findings are consistent with previous studies showing that RBI improves inspection efficiency through risk-based prioritization and that the integration of RBI with operational control parameters improves degradation mitigation [10,24].

3.5. AIM Strengthening Framework

This study proposes an RBI-based AIM strengthening framework consisting of six components: corrosion assessment, remaining life estimation, risk prioritization, inspection optimization, operational control enhancement, and integrity-based mitigation planning. These components are integrated to support adaptive and sustainable integrity management. The proposed framework demonstrates that AIM strengthening depends not only on inspection activities but also on the ability to understand the relationship between material degradation, operational risk, mitigation strategy, and asset sustainability.

The integration of corrosion assessment and remaining life estimation enables operators to evaluate the actual degradation condition more accurately. Risk prioritization then supports inspection and maintenance planning based on actual operational risk. From a strategic perspective, the framework extends RBI beyond inspection scheduling toward broader integrity management that supports long-term operational sustainability. Figure 7 shows the proposed AIM strengthening framework.

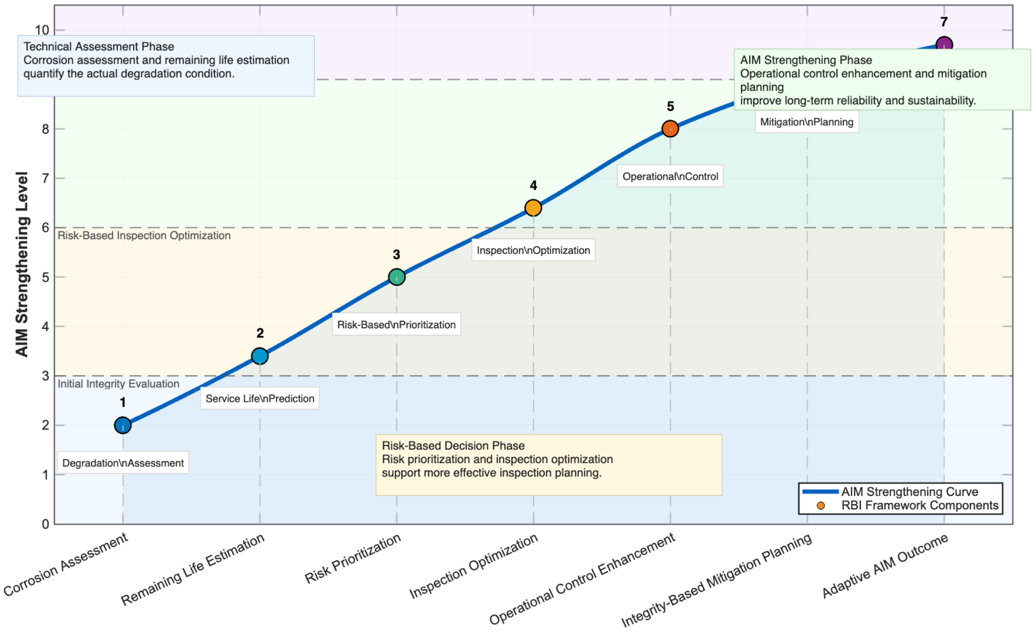

Figure 7. AIM strengthening framework.

3.6. Comparative Discussion

Compared with studies that mainly focus on inspection optimization or probabilistic risk calculation, this study provides a case-based framework using actual industrial inspection data. It connects corrosion rate, remaining life, PoF, CoF, risk category, and inspection planning into one traceable evaluation process.

Previous studies have shown that RBI improves inspection planning, risk-based maintenance, and pipeline integrity management [16], [17], [18], [19]. Other studies have explored dynamic risk assessment, safety barrier management, FMEA-MCDA risk management, digital twin implementation, and data-driven remaining useful life estimation [20], [21], [22], [23], [25]. This study adds value by showing how actual inspection data can be translated into inspection priority and mitigation planning within an AIM context. The contribution of this study should be interpreted as practical decision support, not as proof of a full strategic transformation of AIM. This moderated claim is more consistent with the case study design and the available data, as summarized in Table 1.

Table 2. Comparison between previous studies and the present study.

Aspect	Previous Studies	This Study	Research Added Value
Main research focus	Inspection optimization, quantitative risk calculation, probabilistic assessment, and inspection cost efficiency.	Integration of corrosion evaluation, remaining life assessment, risk ranking, and operational integrity management within AIM.	Provides a broader integrity approach because risk results are linked with asset strategy and operational decision-making.
RBI implementation approach	RBI is commonly used to define inspection priority, inspection interval, and cost-efficient inspection planning.	RBI is used as an integrated integrity evaluation framework connected to degradation, remaining life, operational risk, and maintenance decisions.	Extends RBI from an inspection planning tool into a strategic instrument for strengthening AIM.
Degradation and remaining life evaluation	Some studies do not clearly connect risk optimization with actual degradation condition and remaining service life.	Corrosion rate and remaining life are used to evaluate actual degradation level and serviceability.	Provides a stronger technical basis for inspection prioritization, mitigation planning, and condition-based maintenance.
Risk-based decision-making	Previous studies are more dominant in probabilistic risk assessment, risk matrix, mathematical optimization, or standalone risk calculation.	PoF, CoF, risk ranking, corrosion rate, and remaining life are connected in one integrity evaluation process.	Risk becomes a technical basis for inspection, maintenance, operational control, and mitigation decisions.
Contribution to AIM strengthening	The relationship between RBI and AIM is often limited to inspection efficiency and cost reduction.	AIM links inspection data, degradation assessment, risk prioritization, mitigation strategy, and long-term reliability.	Shows how RBI can strengthen AIM in an adaptive, condition-based, and sustainability-oriented manner.

3.7. Practical Implications

The proposed framework provides direct practical value for operators. It helps identify systems that require earlier inspection and stronger mitigation based on actual inspection data. Utility Water requires closer monitoring because it recorded the highest corrosion rate and the shortest remaining life. Hydrocarbon Gas requires attention because it has a Medium Risk category due to the consequence profile.

For Utility Water, recommended mitigation may include closer UT monitoring, corrosion mapping, water treatment review, deposit control, corrosion inhibitor evaluation, and inspection interval reassessment. For Hydrocarbon Gas, recommended actions may include periodic thickness monitoring, leak history review, external corrosion inspection, operating condition control, and consequence-based inspection planning.

The framework supports risk-informed maintenance because it connects technical data with inspection decisions. This improves inspection efficiency, supports safer operation, and helps allocate inspection resources to the most relevant systems.

4. Conclusions

This study developed a risk-based integrity evaluation framework for hydrocarbon and utility piping systems using 2025 industrial inspection data from 82 evaluated piping lines. The framework integrates corrosion rate, remaining life, PoF-CoF classification, risk ranking, and inspection planning to support inspection prioritization and mitigation planning within an Asset Integrity Management context.

The results show that 80 of 82 evaluated piping lines were categorized as Very Low Risk, 1 Utility Water line was categorized as Low Risk, and 1 Hydrocarbon Gas line was categorized as Medium Risk. Utility Water was identified as the most degradation-sensitive system because it recorded the highest corrosion rate of 0.253 mmpy and the shortest remaining life of 8 years. This condition justifies closer monitoring and an earlier inspection plan for the affected Utility Water line in 2029.

Hydrocarbon Gas recorded a lower corrosion rate of 0.076 mmpy and a remaining life of 38 years. However, it remained in the Medium Risk category due to its consequence profile. This confirms that inspection priority should not be based only on corrosion rate or remaining life. It should combine degradation likelihood and failure consequence.

The proposed framework does not claim to transform the overall AIM system. It provides a practical decision-support method for linking inspection data with inspection priority, risk category, and mitigation planning. Future research should include a wider dataset, full quantitative API RP 581 calculation, probabilistic degradation modelling, real-time corrosion monitoring, digital twin integration, and life cycle cost analysis.

Supplementary Materials: Not applicable.

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Conflicts of Interest: The authors declare no conflicts of interest.

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