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A Case Study of Risk-Based Inspection Implementation in Diesel Fuel Distribution Pipelines

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ABSTRACT

Distribution pipes play an important role in the oil and gas industry, allowing fluids such as crude oil, natural gas, and processed products to move. X Company, an oil and gas company, uses these pipelines to transport diesel fuel from the refinery unit to storage tanks. Proper inspection and maintenance of this pipeline is critical to avoiding issues such as corrosion, cracking, and material failure, which can jeopardize safety, finances, the environment, social stability, legal compliance, and business continuity. This study evaluates a Risk-Based Inspection methodology for ten Thickness Measurement Locations on diesel fuel distribution pipelines using the API 581 standard. The procedure includes a literature review, data collection, assessment of remaining life, calculation of the Probability and Consequence of Failure, risk profiling, and the development of an inspection plan. The results indicate that the pipelines have an average remaining life of 13.14 years. Nine Thickness Measurement Locations were classified as 1C and one as 2C, placing them in the Medium risk category. Every three years, a re-inspection plan is proposed that includes both a 100% visual inspection and targeted non-destructive testing using ultrasonic thickness readings. This study demonstrates how Risk-Based Inspection concepts can be used in practice to improve pipeline integrity inspection procedures. The findings include practical recommendations for increasing safety and operational reliability while reducing inspection costs and risks associated with diesel fuel distribution pipelines.

1. INTRODUCTION

Pipelines are essential components of the oil and gas sector, as they transmit fluids such as crude oil, natural gas, and processed products [1]. X Company, an oil and gas processing corporation, produces and distributes diesel fuel via a network of pipes. According to the Minister of Energy and Mineral Resources' Regulation No. 32 of 2021, all equipment and infrastructure used in oil and gas activities must be subjected to regular technical inspections and safety assessments to verify their reliability and safety.

Pipeline maintenance and inspection are critical to avoiding concerns including corrosion, cracking, and material failure, which represent considerable threats to safety, finances, the environment, legal compliance, and operational continuity [2]. Incidents such as the 2023 gas pipeline explosion in Jakarta, which claimed 35 lives, and the 2014 Pertamina gas pipeline explosion in Subang, which killed three people and injured many others, highlight the critical importance of proactive inspection and maintenance strategies [3].

In Indonesia, safety inspections for oil and gas equipment are commonly conducted in two ways: time-based inspection (TBI) and risk-based inspection (RBI). TBI, a typical method, arranges inspections at predetermined intervals without regard for the risk level or actual operating conditions. In contrast, RBI customizes inspection programs based on the risk profile of the equipment, with higher-risk components undergoing more frequent and concentrated inspections [4]. Campari et al. [5] found that RBI outperformed TBI in terms of adaptability and efficacy when managing inspection protocols for hydrogen filling stations. Moreover, RBI is a systematic approach for prioritizing inspection and maintenance activities based on the likelihood of failure and its potential consequences. In the oil and gas industry, RBI methodologies are increasingly being used to improve pipeline integrity management and ensure safe operations. The API 581 standard is one of the most commonly used frameworks for implementing RBI in pipeline systems.

Recent research has demonstrated the importance of RBI in identifying and mitigating pipeline degradation risks such as corrosion, cracking, and material failure. By combining data on pipe specifications, operational conditions, inspection results, and environmental factors, RBI assists operators in developing targeted inspection strategies and maintenance plans. This approach not only increases safety and environmental protection, but it also optimizes resource allocation and lowers operational costs. Huang [6] investigated a risk-based approach to pipeline inspection planning, taking into account the coupling effect of corrosion and dents. The study emphasizes the need to account for multiple threats to pipeline integrity and suggests using dynamic Bayesian networks to improve risk assessment accuracy. This method allows for more precise identification of high-risk areas and better scheduling of inspections.

Spahić [7] investigated image-based and risk-informed detection of subsea pipeline damage. The study emphasizes the potential of autonomous underwater systems (AUS) equipped with computer vision methods for detecting anomalies in subsea pipelines. Despite challenges such as limited training data and visibility issues, the study suggests generating synthetic data based on risk analysis insights to improve the reliability of AUS inspections. Aditiyawarman [8] also review the use of artificial intelligence (AI) in RBI methodologies. The review emphasizes the benefits of machine learning classifiers like Decision Trees, Logistic Regression, and Random Forests for risk assessment and predictive maintenance. The use of AI tools enables more accurate predictions of equipment condition and severity levels, resulting in better decision-making and increased pipeline reliability.

Therefore, RBI technique provides various benefits, including lower inspection costs, improved safety, prevention of catastrophic equipment failures, increased operational efficiency, and more inspection planning flexibility [9], [10]. RBI promotes more efficient and effective inspection methods by focusing resources on high-risk equipment [11]. RBI is a critical component of modern pipeline integrity management, providing a structured and data-driven approach to ensuring the safe and efficient operation of oil pipelines. Recent technological and research advancements have refined RBI methodologies, making them more effective and efficient in addressing the oil and gas industry's challenges.

This study investigates the use of the RBI method on X Company's diesel fuel distribution pipelines. The objective is on identifying the pipelines' remaining life, assessing the likelihood and consequences of failure, determining risk profiles, and developing specific inspection techniques depending on the established risk levels.

2. METHODOLOGY

This study assesses the use of the API 581-compliant RBI technique to assess the condition and risks related with diesel fuel distribution pipelines at X Company. This study uses a systematic approach to determining the likelihood and effects of failure, hence improving maintenance and inspection operations to avoid costly and hazardous occurrences. This study begins with a thorough analysis of the literature to better grasp RBI's principles and applications. Books, peer-reviewed journals, and trustworthy online resources are used to establish a solid theoretical foundation. By reviewing existing literature, researchers can uncover best practices, past case studies, and theoretical frameworks that enable RBI implementation in industrial settings. This review is critical for developing a solid knowledge basis that will influence following stages of the research.

Furthermore, field data collecting is carried out to gather the information required for the study. Pipe specifications, such as dimensions, material properties, and design details; operational data, such as pressure, temperature, and flow conditions; inspection results from measured thicknesses and previous maintenance records; and environmental data, which reflect the surrounding conditions affecting pipe performance. This comprehensive data gathering guarantees that all important elements are taken into account during the risk assessment process, resulting in an accurate representation of the pipes' actual status and expected behavior under varied scenarios.

The minimum required pipe wall thickness is calculated based on the ASME B31.4 Pipeline Transportation Systems for Liquids and Slurries standard. The relevant equations are as follows (ASME, 2019):

$$t_n \geq t_{req} + CA \quad (1)$$

$$t_{req} = \frac{P_i D}{2S} \quad (2)$$

$$S = F \ x \ E \ X \ S_y \quad (3)$$

Where:

t_n : Nominal pipe wall thickness (inch)
CA : Corrosion allowance (inch)
t_{req} : Required thickness (inch)
P_i : Internal pressure (psi)
S : Allowable stress (psi)
E : Weld joint factor
F : Design factor
S_y : Specific minimum yield strength (psi)

Using API 570, the corrosion rate (CR) and remaining life (RL) of the pipes are determined as follows:

$$Corrosion\ Rate\ (CR) = \frac{t_{initial} - t_{actual}}{Interval\ Year} \quad (4)$$

$$Remaining\ Life\ (RL) = \frac{t_{actual} - t_{required}}{CR} \quad (5)$$

Where:

CR : Corrosion rate (mm/year)
RL : Remaining pipe life (years)
$t_{initial}$: Initial pipe thickness (mm)
t_{actual} : Measured thickness (mm)
$t_{required}$: Minimum required thickness (mm)

Furthermore, the risk assessment is performed using the API 581 methodology by calculating the Probability of Failure (PoF) and Consequence of Failure (CoF).

$$Pof = g_{ff} \ x \ D_f(t) \ x \ F_{MS} \quad (6)$$

Where:

PoF : Probability of Failure
g_{ff} : Generic failure frequency
$D_f(t)$: Damage factor
F_{MS} : Management system factor

Moreover, the Consequence of Failure (CoF) calculation involves determining the leak hole size, leakage rate, and release duration. The liquid discharge rate (QL) is calculated as:

$$Q_L = C_d \ A \sqrt{2\rho - \rho \frac{g_c}{144}} \quad (7)$$

Where:

Q_L : Liquid discharge rate (lbs/sec)

C_d : Discharge coefficient (0.61)
A : Hole cross-sectional area (sq. in)
ρ : Fluid density
g_c : Conversion factor

Based on the type of release (continuous or instantaneous), adjustments are made using specific equations to calculate the consequence area (CA) for component damage and personnel injury. Then, risk is determined using the equation:

$$Risk = PoF\ x\ Cof \tag{8}$$

The results are categorized using a risk matrix as shown in Figure 1. The risk assessment process integrates the likelihood of failure and related consequences by means of a matrix to classify and assess possible hazards. Based on occurrence rates, five separate groups define the likelihood of failure. Category 1 indicates a probability of failure less than 0.00010; Category 5 shows probabilities between 0.1 and 1, so indicating a greater chance of failure. Specifically 0.0001–0.001, 0.001–0.01, and 0.01–0.1, intermediate categories (2 to 4) span increasingly wider probability ranges.

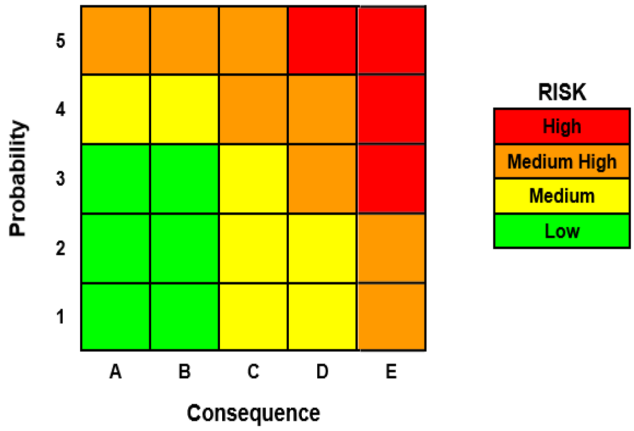

Figure 1. Risk matrix of the probability of failure versus consequence of failure [12]

Similar classification of the effects of failure depends on the affected area, expressed in square feet (ft²). With a CA of less than 100 ft², Category A shows minimal impact; Category E shows severe consequences with a CA exceeding 10,000 ft². Between 100 and 1,000 feet², Category B for areas between 1,000 and 3,000 feet², and Category D for areas between 3,000 and 10,000 feet², intermediate categories offer a more exact classification.

Combining these categories in a risk matrix helps one create a suitable inspection plan. To assess the state of the pipeline system, this covers choosing techniques including 100% visual inspection and Non-Destructive Testing (NDT) devices including Ultrasonic Thickness Gauge (UT Spot). The computed risk levels then define the inspection intervals, which guarantees timely and efficient maintenance operations to prevent possible failures.

For the X Company pipeline, visual inspections and ultrasonic testing (UT) revealed that thinning was the primary damage factor. The parameter of damage factor is calculated using Equation 9.

$$A_{rt} = max\left[\left(1 - \frac{t_{act} - Cr.age}{t_{min} + CA}\right), 0.0\right] \tag{9}$$

Then, the management system score was evaluated as 847. Using Equations (10) and (11), The value of Fms is 0.202.

$$pscore = \frac{score}{1000} x100 \tag{10}$$

$$F_{ms} = 10^{(-0{,}02*pscore+1)} \quad (11)$$

The leakage rate is calculated using Equation (12). The liquid discharge rate (QL) is calculated as:

$$Q_L = C_d\ A \sqrt{2\rho - \rho \frac{g_c}{144}} \quad (12)$$

Where:
Q_L : Discharge rate of liquid (lbs/sec)
C_d : Coefficient of discharge (0.61)
A : Hole cross-sectional area (sq. in)
ρ : Density of fluid
g_c : Factor of conversion

The consequence area is calculated using Equations (15) and (16). Constants a and b are derived from API 581 Table 5.8.

$$CA_n^{Cont} = a\ (rate_n)^b \quad (15)$$

$$CA_n^{Inst} = a\ (mass_n)^b \quad (16)$$

For a continuous leak (0.25-inch hole), CA_n^{Cont}= 20.06 ft². For an instantaneous rupture, CA_n^{Inst}= 9979.19 ft². Table 1 lists the values for other hole sizes:

Table 1. Consequence Area due to component damage

Realease hole size (Inch)	Release type	a	b	$CA_{cmd.n}$ (ft²)
0.25	*continuous*	64	0.9	20.06
1	*continuous*	64	0.9	243.28
Rupture	*instantaneous*	0.46	0.88	9979.19

$$CA_{cmd} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{cmd,n}}{gff_{total}}\right) \quad (17)$$

Furthermore, cosequence area due to personnel injury is presented in Table 2, calculated using Equation (15) and (16). Constants a and b are derived from API 581 Table 5.8.

Table 2. Consequence areas due to personnel injuries

Realease hole size (Inch)	Release type	a	b	$CA_{inj.n}$ (ft²)
0.25	*continuous*	183	0.89	58.11
1	*continuous*	183	0.89	685.37
Rupture	*instantaneous*	1.3	0.88	28202.07

$$CA_{inj} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{inj,n}}{gff_{total}}\right) \quad (18)$$

3. RESULTS AND DISCUSSION

3.1 Distribution Pipe Identification

X Company's distribution pipes were found and examined to expose several important characteristics essential for their performance and operation compatibility. API 5L Grade B material is used to build the pipes; their Specified Minimum Yield Strength (SMYS) is 35.5 ksi. Made in 2019, their 4-

inch size with 4.5-inch outside diameter is rather small. The design factor is 0.5, which corresponds to Location 3; the flawless construction produces a weld joint factor (E) of 1. Their design considers a 0.125 inch corrosion allowance.

Designed for solar service fluid within the range of C13–C17 hydrocarbons, with a molecular weight of 205 and a density of 47.728 lb/ft^3, the pipes are meant to run at a pressure of 136.54 psi. With a normal boiling point of 502 °F, a specific heat (Cp) of -11.7.7 lbf-s/ft^2, and a fluid dynamic viscosity of 7.706E-4 lbf-s/ft^2 the fluid shows Under ambient conditions, the fluid stays liquid and has a 396 °F auto-ignition temperature. These features guarantee that the pipes satisfy operational needs and preserve dependability and safety in use.

3.2 Inspection Result Data

The inspection process included a 100% visual inspection to identify surface defects and ultrasonic thickness measurements at 10 Thickness Measurement Locations (TMLs). No external pipe damage was observed; however, thinning damage was detected. The thickness measurements are detailed in Table 3.

Table 3. Thickness Measurement Data

TML	Initial Thickness, Tint (mm)	Minimum Actual Thickness at TML, Tact (mm)
1	8.56	6.3
2	8.56	6.0
3	8.56	6.6
4	8.56	5.8
5	8.56	6.2

3.3 Corrosion Rate Analysis and Remaining Life Determination

The required minimum thickness is calculated using the previous formula. For TML 1. the calculations yield: 0.0173 inch or 0.4396 mm. The nominal pipe wall thickness is calculated as: 0.142 inch or 3.61 mm. ince the actual thickness at TML 1 is 6.3 mm > 3.6 mm. the pipe is suitable for use. Corrosion rate can be calculated using Equation 4, while remaining life can be calculated using Equation 5. The result of corrosion rate and remaining life at TML 1 respectively are 0.45 mm/year and 13.0 years. For other TML corrosion rate and remaining life are showed in Table 4.

Table 4. Thickness required, Corrosion Rate, and Remaining Life Calculation

TML	Treq(mm)	Tn (mm)	CR (mm/year)	RL (Year)
1	0.44	3.61	0.45	13.0
2	0.44	3.61	0.51	10.9
3	0.44	3.61	0.39	15.7
4	0.44	3.61	0.55	9.7
5	0.44	3.61	0.47	12.2

Furthermore. Figure 2 illustrates the relationship between corrosion rate and remaining life. showing that higher corrosion rates correspond to shorter remaining life.

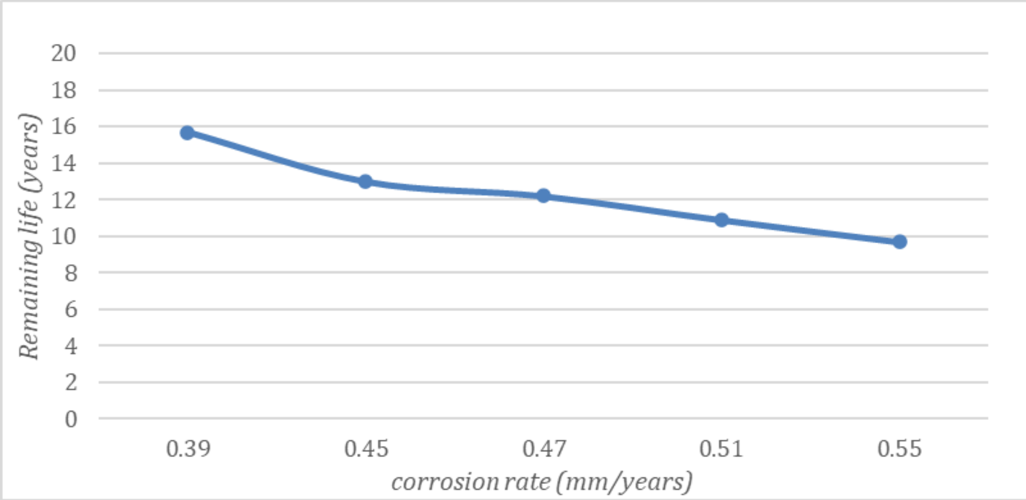

Figure 2. Relationship between corrosion rate and remaining life

From the calculation. TML 4 was identified as having the most critical remaining life at 9.7 years. while TML 3 showed a longer remaining life of 15.7 years. The average remaining life of the pipeline was determined to be 12.3 years. which varies due to differences in corrosion rates. TML 4 experienced the highest corrosion rate at 0.55 mm/year. while TML 3 had the lowest at 0.39 mm/year. Figure 3 illustrates the inverse relationship between corrosion rate and remaining life: higher corrosion rates lead to shorter remaining lives. Corrosion is influenced by two primary factors:

- Internal Factors: Fluids flowing within the pipeline.
- External Factors: Exposure of the pipeline to air and the surrounding environment [13].

The remaining life calculation is a vital evaluation step to ensure the equipment's operational safety and feasibility. It forms the basis for establishing risk and inspection strategies.

3.4 Risk Analysis

3.4.1 Probability of Failure

The damage factor accounts for potential causes of failure. According to API 581 [12]. the damage factors include thinning (Df_thin), component linings (Df_elin), external damage (Df_extd), stress corrosion cracking (Df_scc), high-temperature hydrogen attack (Df_htha), mechanical fatigue (Df_mfat) and brittle fracture (Df_brit). The base thinning damage factor is then determined by matching Art with inspection effectiveness based on API 581 Table 5.5. The pipeline inspection falls under Category C (Fairly Effective) due to visual inspections and spot thickness measurements via ultrasonic testing, as shown in Table 5.

Table 5. Thinning Damage Factor [12]

Art	1 Inspection				
	E	**D**	**C**	**B**	**A**
0.02	1	1	1	1	1
0.04	1	1	1	1	1
0.06	1	1	1	1	1
0.08	1	1	1	1	1
0.1	2	2	1	1	1
0.12	6	5	3	2	1
0.14	20	17	10	6	1
0.16	90	70	50	20	3
0.18	250	200	130	70	7
0.2	400	300	210	110	15
0.25	520	450	290	150	20

Art	1 Inspection				
	E	**D**	**C**	**B**	**A**
0.3	650	550	400	200	30
0.35	750	650	550	300	80
0.4	900	800	700	400	130
0.45	1050	900	810	500	200
0.5	1200	1100	970	600	270
0.55	1350	1200	1130	700	350
0.6	1500	1400	1250	850	500
0.65	1900	1700	1400	1000	700

According to the API 581 standard (Table 5.11) and the data provided in Table 9. the base thinning damage factor at Art = 0 is 1. The base thinning damage factor values for various TMLs are presented in Table 6.

Table 6. *Base Thinning Damage Factor*

TML	Art	$\boldsymbol{D_{fb}^{thin}}$
1	0.00	1
2	0.05	1
3	0.00	1
4	0.16	50
5	0.00	1

The damage factor parameter Art is influenced by the actual thickness, corrosion rate, inspection interval, minimum material thickness, and corrosion allowance. A higher corrosion rate results in a greater Art value. as evidenced by TML 9. which has the highest corrosion rate and a correspondingly large Art. The value of the damage factor due to thinning is influenced by several adjustments. including:

- Adjustment for On-line Monitoring (FOM): 1 (No on-line monitoring in use)
- Adjustment for Injection/Mix Points (FIP): 1 (No injection points present)
- Adjustment for Dead Legs (FDL): 1 (No dead legs present)
- Adjustment for Welded Construction (FWD): 1 (Specifically for tank construction)
- Adjustment for Maintenance (FAM): 1 (Specifically for tank maintenance)
- Adjustment for Settlement (FSM): 1 (Specifically for tank foundation)

The total thinning damage factor then can be calculated using Equation (17). The damage factor values for other TMLs are presented in Table 7.

Table 7. *Damage Factor of Thinning*

TML	Thinning $\boldsymbol{D_{f}^{thin}}$
1	1
2	1
3	1
4	50
5	1

c. Management System Factor (FMS)

By means of a thorough assessment of the management system or operational unit, with an eye toward important elements affecting safety and efficiency, the value of the facility management system (FMS) is ascertained. These elements cover many facets of operational management, including process hazard analysis, information on process safety, and administration and leadership. Further strengthening the system are good change management, clearly defined operating policies, and adherence to safe work practices. Operating dependability is guaranteed by other elements including pre-startup safety reviews, mechanical integrity checks, and strong training programs. Maintaining a high-performance FMS also depends critically on emergency response readiness, exhaustive incident investigations, contractor oversight, and frequent audits. These components taken together create a whole framework for supporting a strong, safe, and effective operational environment.

The Probability of Failure can be calculated using Equation (6). For TML 1 is 0.000006. Matching this result with Table 1, the PoF for TML 1 falls under Category "1". The calculated PoF values for all TMLs are presented in Table 8.

Table 8. Results of Probability of Failure Calculation

TML	g_{ff}	D_f	F_{ms}	PoF	Category
1	0.00003	1	0.202	0.000006	1
2	0.00003	1	0.202	0.000006	1
3	0.00003	1	0.202	0.000006	1
4	0.00003	50	0.202	0.000303	2
5	0.00003	1	0.202	0.000006	1

3.4.2. Determination of the Consequence of Failure (CoF)

Step 1: Determining Leak Hole Sizes

Based on API 581 for a 4-inch pipe, the potential leak hole sizes are: ¼ inch, 1 inch, and Rupture (min[D, 16])

Step 2: Calculating Leakage Rate (QL)

The leakage rate is calculated using Equation (7). For a 0.25-inch leak: QL = 0.276 lb/sec, while for 1 inch and rupture, QL = 4,409 lb/sec and 70,546 lb/sec respectively.

Step 3: Leak Duration (ldmax)

The leak duration depends on the detection and isolation system. In this case: Detection System: Visual (Category "C") and Isolation System: Manually Operated Valve (Category "C"). According to API 581 Table 5.6, the reduction factor for Detection C and Isolation C is 0. The leak durations for 0,25 inch,1 inch, and Rupture are 60 minute, 40 minute, and 20 minute, respectively.

Step 4: Determining Leak Type

Leaks are classified as continuous for total fluid leakage <10,000 lbs in 3 minutes and instantaneous for total fluid leakage ≥10,000 lbs in 3 minutes. Table 9 summarizes the leak types.

Table 9. types of leaks for each hole

Release Hole Size (Inch)	Laju kebooran, Q_L (lb/sec)	Total leak mass in 3 minutes (lbs)	*Release Type*
0,25	0,276	49,60	*continuous*
1	4,409	793,65	*continuous*
Rupture	70,546	12698,36	*instantaneous*

Step 5: Adjusted Leakage Rate and Mass

Adjusted leakage rate and released mass are calculated using Equations (8) and (9). For a 0.25-inch hole, Rate n = 0.276lb/sec. Mass n = 992.06 lbs. Values for other hole sizes are shown in Table 10.

Table 10. Mass of fluid released

Release Hole Size (Inch)	Adjusted Release Rate, $rate_n$ (lb/s)	Leak Duration, ld_n (s)	Release Mass, $mass_n$ (lbs)
0,25	0,276	3600	992,06
1	4,409	2400	10581,97
Rupture	70,546	1200	84655,73

Step 6: Consequence Area Due to Component Damage

The consequence area is calculated using Equations (10) and (11). Constants a and b are derived from API 581 Table 5.8. For a continuous leak (0.25-inch hole), CA n Cont = 20.06 ft². For an instantaneous rupture, CA n Inst = 9979.19 ft². Table 11 lists the values for other hole sizes:

Table 11. Consequence Area due to component damage

Realease hole size (Inch)	Release type	a	b	$CA_{cmd,n}$ (ft²)
0,25	*continuous*	64	0,9	20,06
1	*continuous*	64	0,9	243,28
Rupture	*instantaneous*	0,46	0,88	9979,19

The value of consequence area due to component damage is calculated using Equation 17. The result is 1012.15 ft².

Step 7: Consequence Area Due to Personnel Injury

Cosequence area due to personnel injury is calculated using Equation (15) and (16). Constants a and b are derived from API 581 Table 5.8. The results are shown in Table 12.

Table 12 consequence areas due to personnel injuries

Realease hole size (Inch)	Release type	a	b	$CA_{inj,n}$ (ft²)
0,25	*continuous*	183	0,89	58,11
1	*continuous*	183	0,89	685,37
Rupture	*instantaneous*	1,3	0,88	28202,07

Step 8: Final Consequence Area

The final consequence areas are determined using Equations (12) and (13). For component damage, CA_{cmd} = 1012.15 ft² while for personnel injury, CA_{inj} = 2859.40 ft². The final consequence area was determined using equation (14), yielding a value of 2,859.403 ft². This value exceeds the component damage consequence area (1,012.15 ft²) and categorizes the consequence of failure (CoF) as "C" based on Table 2.

3.4.2 Risk Categorization

Risk is assessed as the product of the probability of failure (PoF) and the consequence of failure (CoF). The analysis indicates that 4 TMLs fall into the risk category of 1C (medium). while 1 TML is categorized as 2C (medium). These results are summarized in Table 20 and visualized using the 5x5 risk matrix (Figure 4).

Table 20 Risks posed by equipment

TML	Probability of Failure	Consequence Of Failure	Risk	Categoty
1	1	C	1C	Medium
2	1	C	1C	Medium
3	1	C	1C	Medium
4	2	C	2C	Medium
5	1	C	1C	Medium

All identified risks for X Company's distribution pipes are in the "Medium" category, emphasizing the importance of proactive risk control and mitigation to prevent escalation to higher-risk levels. Suggested mitigation measures include regular pipe wall thickness monitoring, remaining life assessment, corrosion rate calculations, application of protective coatings, and maintaining comprehensive equipment history records [14], [15].

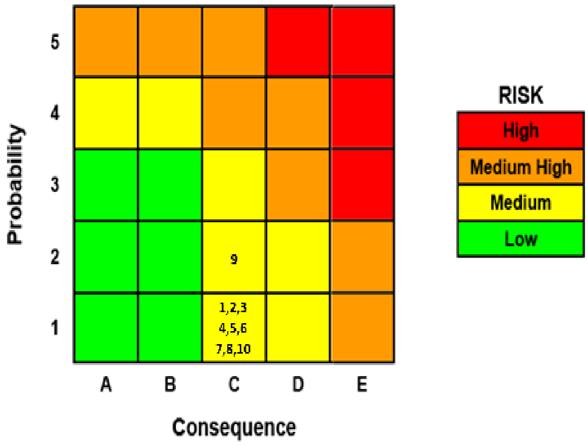

Figure 4 Risk Matrix of X Company Distribution Pipe

3.5 Inspection Strategy

An effective inspection strategy is crucial to maintaining pipeline integrity and mitigating risk. This strategy includes selecting appropriate inspection methods and intervals. The API 570 standard and risk-based approaches from API 581 were employed to determine inspection intervals. Using the half-life interval method, the next inspection for TML 9, which has the shortest remaining life of 9.71 years, should occur in 4.85 years (rounded to 5 years). For medium-risk equipment, API 581 recommends ultrasonic thickness (UT) inspections every 30 months in partial areas.

Based on these analyses, the selected inspection method for X Company pipelines includes:

- 100% visual inspection to detect surface damage.
- UT inspections for partial areas to measure wall thickness, performed at 3-year intervals.

Additional inspection methods, such as ultrasonic straight beam, eddy current, flux leakage, radiography, and dimensional measurement, could be employed as needed. However, visual and UT inspections were deemed the most effective and efficient given the predominant damage mechanisms identified.

4. CONCLUSION

In the oil and gas sector, pipelines are essential infrastructure for the movement of resources. Given their importance, regular inspection and maintenance of them guarantees their safe and effective running conditions. Though efficient, traditional inspection techniques sometimes lack a targeted approach and may be resource-intensive. This difficulty emphasizes the need of RBI, a technique that maximizes inspection activities depending on equipment risk level so optimizing both safety and efficiency. This study aims to assess X Company's distribution pipelines' condition and degree of risk in order to create a customized inspection plan. With all TMLs categorized as medium risk, this study found an average remaining service life of 13.14 years for the pipelines. These results underline the need of using an inspection plan that strikes a mix between thoroughness and economy.

A good inspection program is suggested to help to reduce risks and guarantee the pipeline system's ongoing dependability. This method calls for partial-area ultrasonic thickness measurements spaced three years apart and 100% visual inspections. This strategy minimizes the possibility of safety events, financial losses, environmental damage, and operational interruptions by matching the recognized medium risk levels and is meant to solve possible material failures before they become more noticeable. The X Company can improve the operational life, dependability of its pipeline systems, and industry standards for safety and sustainability by including RBI ideas into the maintenance program. This study underlines RBI as a vital instrument for maximizing oil and gas sector inspection procedures, so guaranteeing long-term operational excellence and resilience.

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