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Corrosion Control Management of Pipelines of Oil and Gas Industries

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Abstract

Corrosion in oil and gas pipelines poses significant risks to operational reliability, economic performance, environmental safety, and public welfare, particularly in coastal and high-humidity regions. This study aimed to assess corrosion risks in oil and gas pipeline systems in Batangas Province, Philippines, and to develop a structured, risk-based Corrosion Control Management System (CCMS) to support effective decision-making. Anchored on Failure Mode and Effects Analysis (FMEA), the study employed a mixed-method research design integrating site observations, structured interviews, document review, and quantitative risk analysis. Respondents included engineers, maintenance personnel, corrosion specialists, and technical staff from six oil and gas companies operating pipeline systems in Batangas. Environmental and operational factors contributing to corrosion were identified, including coastal exposure, soil composition, humid tropical climate, pipeline pressure, temperature, and transported fluid composition. FMEA results identified ten major corrosion-related failure modes, with microbiologically influenced corrosion, internal corrosion, soil-side corrosion, and delayed corrosion detection ranked as the most important based on Risk Priority Numbers. Variability analysis further indicated that certain failure modes require site-specific verification due to differences in operating conditions and inspection practices. Based on these findings, a CCMS was developed by integrating risk prioritization, variability assessment, and corrosion control selection aligned with recognized international standards. Evaluation of the proposed CCMS indicates its potential to reduce corrosion-related maintenance costs, minimize unplanned downtime, and lower the likelihood of environmental incidents through preventive, risk-based interventions. The study concludes that systematic integration of FMEA into corrosion management enhances pipeline integrity, operational efficiency, and environmental protection. The research supports Sustainable Development Goals related to Industry, Innovation and Infrastructure (SDG 9), Responsible Consumption and Production (SDG 12), Climate Action (SDG 13), and Decent Work and Economic Growth (SDG 8) by promoting safe, efficient, and sustainable pipeline operations. The sustainability impact of the study lies in strengthening institutional risk governance, reducing environmental risks associated with corrosion-related failures, and supporting long-term infrastructure resilience in the energy sector.

Keywords: Corrosion control management system; Failure Mode and Effects Analysis; microbiologically influenced corrosion; oil and gas pipelines; pipeline corrosion; risk assessment; sustainability; tropical coastal environment

1. Introduction

Corrosion in oil and gas pipelines remains a significant challenge that threatens operational reliability, economic stability, environmental safety, and public well-being. Pipelines are essential infrastructure for transporting petroleum products and natural gas across long distances and varied environments, making their integrity vital for uninterrupted energy supply. However, corrosion—an unavoidable material degradation process driven by environmental and operational interactions—continues to compromise pipeline performance, leading to failures, leaks, and substantial financial and ecological consequences (D. Landolt, 2007; Davis, 2000; Perez, 2013). In the Philippine context, particularly in Batangas Province, pipeline corrosion risks are intensified by coastal exposure, high humidity, saline environments, and demanding operational conditions. Given Batangas' strategic role in national energy distribution, the need for a structured, risk-based corrosion control management approach is imperative. This study addresses this need by applying Failure Mode and Effects Analysis (FMEA) to assess corrosion risks and develop a decision-making framework for selecting cost-effective, operationally efficient, and environmentally sustainable corrosion control strategies (Stamatis, 2003; Xiao et al., 2011).

1.1 Corrosion Challenges in Oil and Gas Pipelines within Batangas Province

Corrosion is defined as the deterioration of materials due to chemical or electrochemical interaction with their environment and can occur at any stage of oil and gas processing (D. Landolt, 2007). In pipeline systems, corrosion arises from exposure to moisture, oxygen, hydrogen sulfide, carbon dioxide, chlorides, microbial activity, and stress, often under high-pressure and high-temperature conditions. These factors accelerate material degradation, resulting in pitting, uniform thinning, cracking, and eventual rupture (Michael Baker Jr., 2008; Revie & Uhlig, 2011). The consequences of unmanaged corrosion include increased maintenance and replacement costs, production downtime, safety hazards, regulatory non-compliance, and environmental contamination (Davis, 2000; Perez, 2013). In response, oil and gas industries employ corrosion control measures such as protective coatings, cathodic protection systems, corrosion inhibitors, material selection, and non-destructive inspection techniques (American Petroleum Institute, 2020; Speight, 2014). Despite these measures, corrosion remains persistent, emphasizing the need for systematic and localized corrosion control management.

1.2 Pipeline Systems for Oil and Gas Transport

Oil and gas pipelines form the backbone of global and national energy distribution systems, enabling the efficient transport of hydrocarbons from production sites to refineries and end-users (Wang et al., 2019; International Energy Agency, 2021). These pipelines are broadly classified into liquid petroleum pipelines and natural gas pipelines, each with distinct operational characteristics.

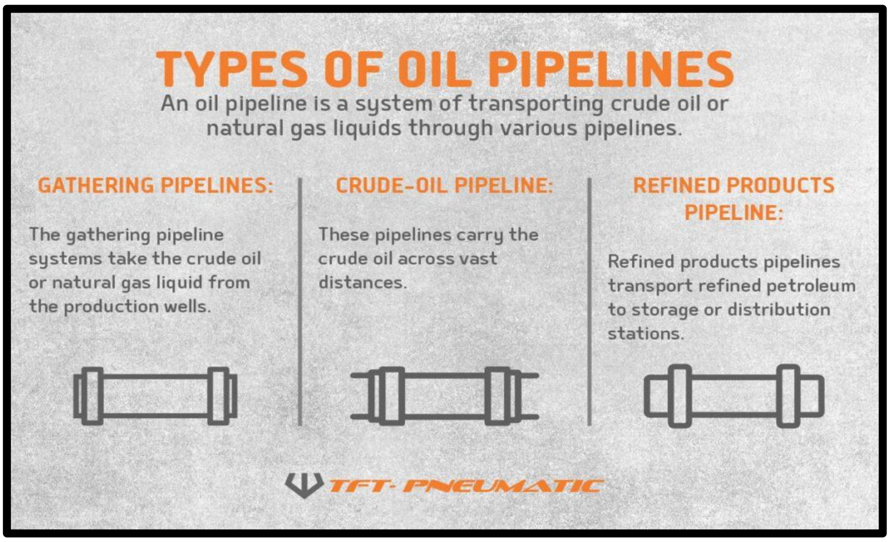

Figure 1. Types of Oil Pipelines
Source: TFT-Pneumatic, 2024

Figure 1 illustrates the major types of oil pipelines, including gathering pipelines that transport crude oil from wellheads, crude-oil pipelines that convey oil over long distances to refineries, and refined product pipelines that distribute processed fuels to storage and consumption points (TFT-Pneumatic, 2024). These pipeline types differ in pressure levels, transported fluids, and exposure conditions, all of which influence corrosion behavior. Similarly, natural gas pipeline systems consist of gathering, transmission, and distribution pipelines.

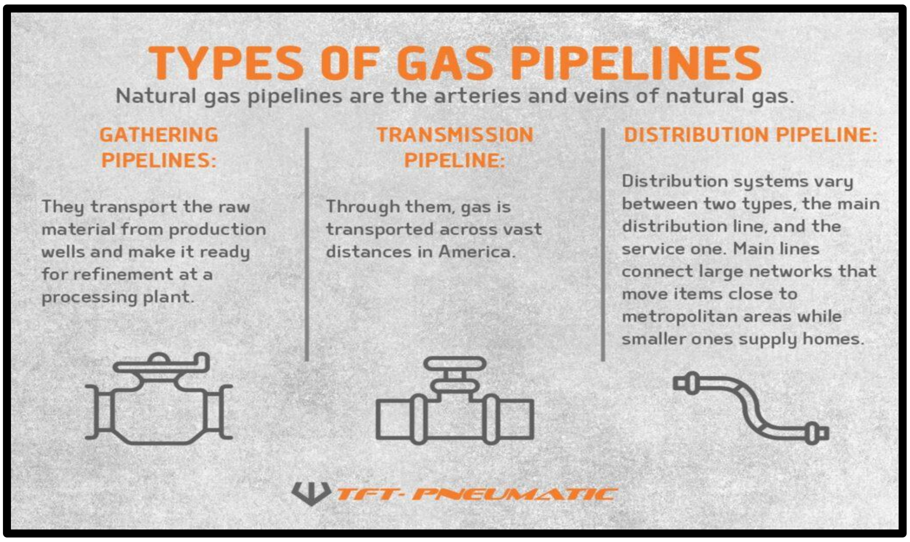

Figure 2. Types of Oil Pipelines
Source: TFT-Pneumatic, 2024

Figure 2 presents this classification, highlighting how gas is collected from production wells, transported across long distances at high pressures, and distributed to industrial, commercial, and residential users. Each segment faces unique corrosion risks due to variations in pressure, moisture content, and chemical composition of the transported gas.

1.3 Types of Pipeline Corrosion

Figure 3. Pipeline damage from pitting
Source: Pipeline and Hazardous Materials Safety Administration, 2019

Figure 4. General (uniform) corrosion
Source: Handbook of Environmental Degradation of Materials (3rd Edition), 2018

Pipeline corrosion occurs both internally and externally due to environmental exposure and interaction with transported fluids (D&D Coatings, 2019). Several corrosion forms affect pipeline integrity. Pitting corrosion, one of the most dangerous forms, results in localized metal loss that can rapidly lead to rupture. Figure 3 demonstrates pipeline damage caused by pitting corrosion, showing how isolated or overlapping pits weaken the pipe wall and eventually cause failure (Michael Baker Jr., 2008). Uniform corrosion involves the even thinning of the pipe wall over time. Figure 4 illustrates this generalized metal loss, which, although gradual, significantly reduces structural strength when left unmanaged (S.N. Karlsdottir, 2018). Galvanic corrosion occurs when dissimilar metals are electrically connected in a conductive environment.

Figure 5. Galvanic corrosion
Source: Galvanic Corrosion: Causes, Prevention and Testing. (n.d.)

Figure 6. Crevice Corrosion
Source: Orapi Asia, 2024

As shown in Figure 5, one metal becomes anodic and corrodes preferentially, depending on potential differences and environmental resistivity (Zaki Ahmad, 2023). Crevice corrosion is a localized attack occurring in confined spaces where stagnant solutions accumulate. Figure 6 depicts crevice corrosion typically observed in marine or biofouling environments (Abdel Salam H. et al., 2018).

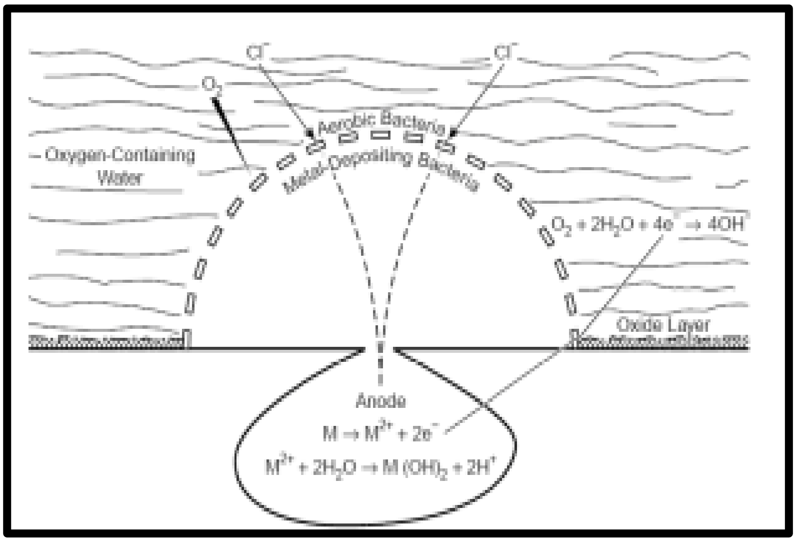

Figure 7. Possible reactions under tubercles created by metal depositing bacteria.
Source: Peabody's Control of Pipeline Corrosion, 2nd Edition, p. 280

Microbiologically influenced corrosion (MIC), illustrated in Figure 7, is caused by bacteria such as sulfate-reducing and acid-producing bacteria that accelerate corrosion through biofilm formation and electrochemical reactions (Michael Baker Jr., 2008).

1.4 Environmental and Operational Context of Pipeline Corrosion in the Philippines

Globally, corrosion imposes significant economic losses and safety risks across industries (Caldona, 2013). In the Philippines, corrosion is intensified by high humidity, saline air, rainfall, and industrial pollutants, particularly in coastal provinces such as Batangas (Emel Ken Benito et al., 2017).

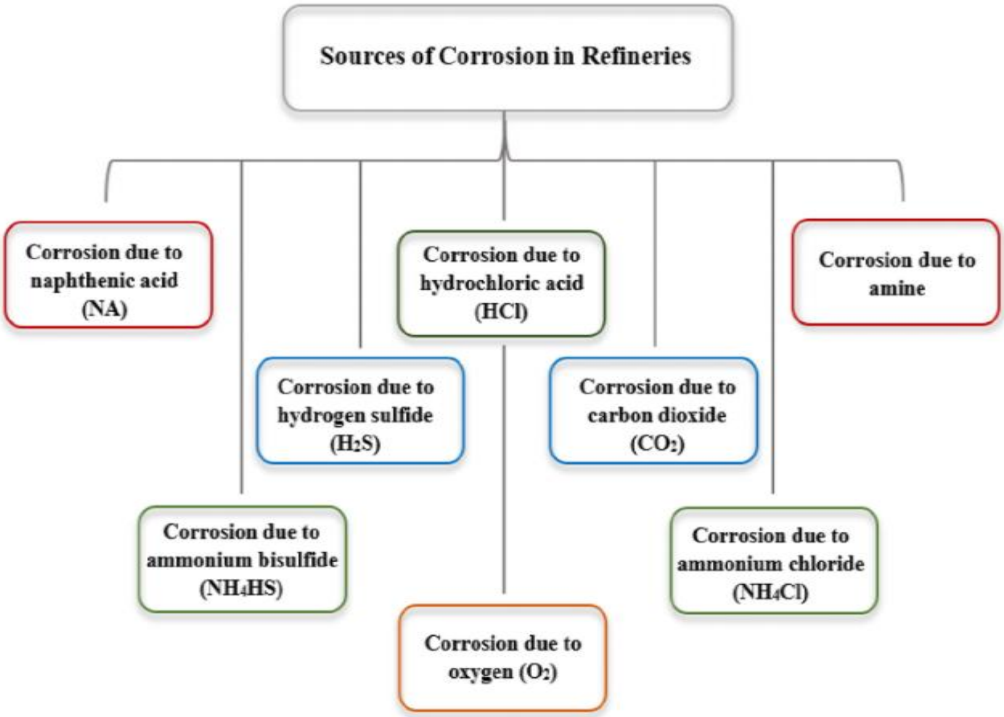

Figure 8. The main sources of corrosion in refineries
Source: Al-Moubaraki and Obot, 2021

Figure 8 summarizes the primary sources of corrosion in refinery operations, including crude oil impurities, process chemicals, and environmental exposure (Al-Moubaraki and Obot, 2021). These factors interact with pipeline materials under varying operational conditions, accelerating corrosion and increasing the likelihood of failures that can disrupt national energy supply.

1.5 Corrosion Protection and Management Approaches for Pipeline Integrity

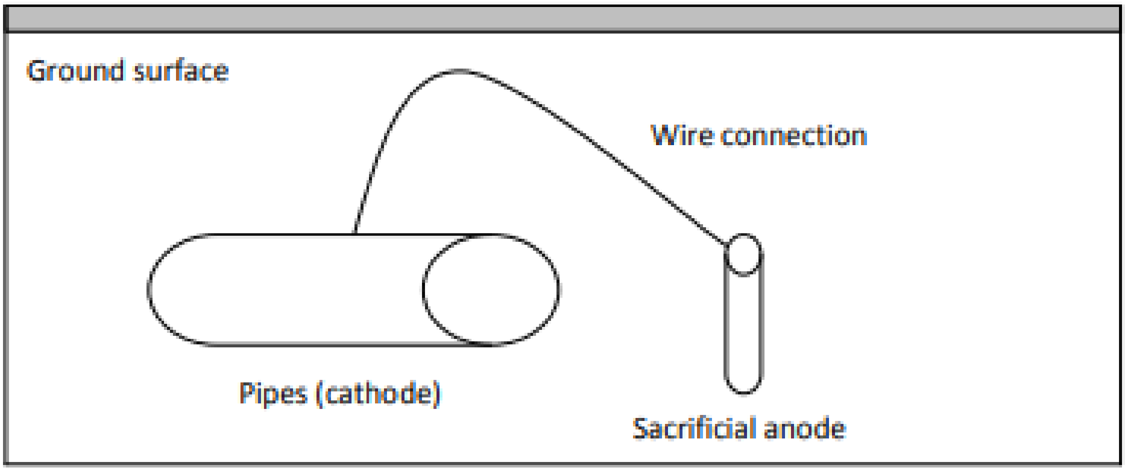

Figure 9. Mechanism of protection of metal by sacrificial anode method
Source: Wiley Engineering Chemistry, 2nd Edition

Corrosion mitigation strategies include protective coatings, cathodic protection systems, corrosion inhibitors, and proper engineering design (Speight, 2014). Protective coatings act as physical barriers, while cathodic protection systems alter electrochemical reactions to prevent metal dissolution. Figure 9 illustrates the sacrificial anode method, where a more active metal corrodes in place of the pipeline material.

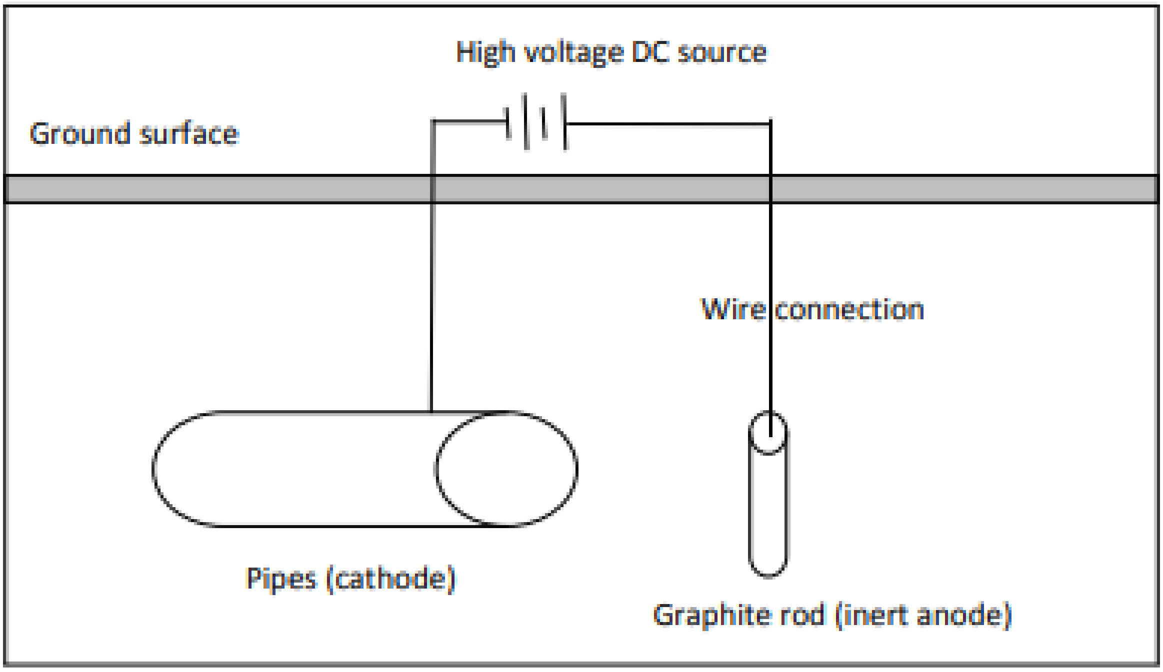

Figure 10. Mechanism of protection of metal by impressed current method
Source: Wiley Engineering Chemistry, 2nd Edition

Figure 10 presents the impressed current method, which uses an external power source to control corrosion electrochemically. Both methods are widely applied in pipeline systems to enhance service life. Corrosion management systems (CMS) integrate these technical controls with organizational policies and performance monitoring.

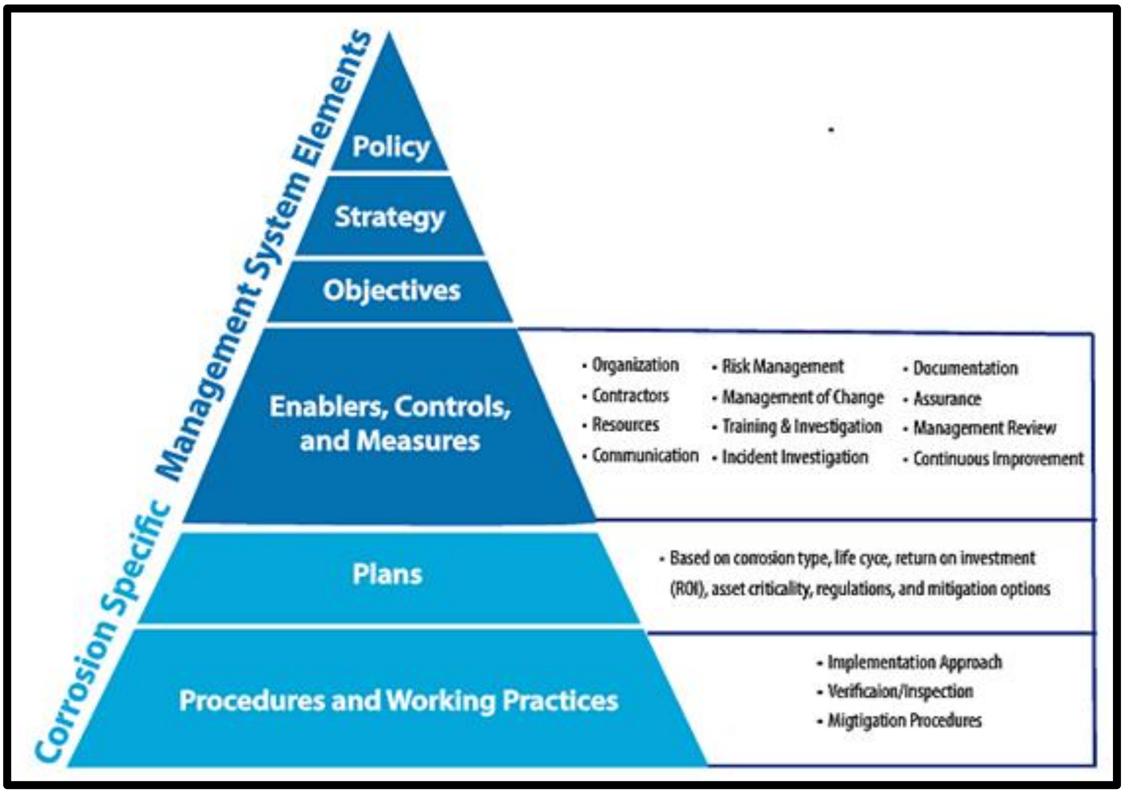

Figure 11. Corrosion Management System Pyramid
Source: NACE International, 2020

Figure 11 presents the CMS Pyramid, emphasizing the role of procedures, planning, and management commitment in ensuring effective corrosion control (NACE International, 2020).

1.6 Failure Mode and Effects Analysis (FMEA) as the Study's Analytical Framework

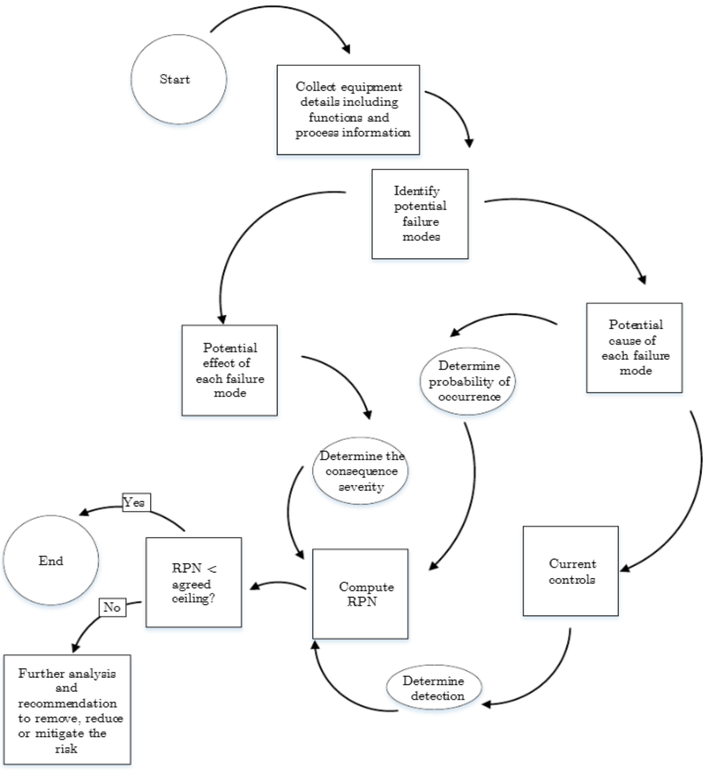

Figure 12. Traditional FMEA Process

Source: Al-Moubaraki and Obot, 2021

FMEA is a structured, bottom-up risk assessment methodology used to identify failure modes, evaluate their effects, and prioritize risks based on severity, occurrence, and detectability (Carlson, 2014; Singh, 2014). Figure 12 illustrates the traditional FMEA process, demonstrating how failure modes are systematically analyzed to calculate Risk Priority Numbers (RPN), which guide mitigation strategies. By applying FMEA to pipeline corrosion in Batangas Province, this study provides a systematic basis for prioritizing corrosion risks and selecting appropriate control measures aligned with operational and environmental conditions (Stamatis, 2003).

1.7 Research Gaps, Sustainability Alignment, and Study Significance

Despite extensive global research, localized corrosion control frameworks adapted to the environmental and operational conditions of Batangas pipelines remain limited (Li et al., 2020; Solovyeva et al., 2023). This study addresses this gap by integrating FMEA with sustainability-based evaluation criteria. The research aligns with SDG 8 (Decent Work and Economic Growth), SDG 9 (Industry, Innovation and Infrastructure), SDG 12 (Responsible Consumption and Production), and SDG 13 (Climate Action) by promoting safe, efficient, and environmentally responsible pipeline operations. From a multidisciplinary sustainability perspective, the study supports socio-economic stability, environmental protection, institutional risk governance, and technological sustainability by enhancing pipeline integrity and minimizing corrosion-related failures.

2. Material and methods

2.1 Research Design

The study employed a mixed-method research design combining qualitative and quantitative approaches to systematically assess corrosion risks and develop a corrosion control management framework for oil and gas pipelines in Batangas Province. Qualitative components included site visits, observations, and structured interviews to capture operational practices, environmental exposure, and existing corrosion control measures. Quantitative analysis was conducted using the Failure Mode and Effects Analysis (FMEA) methodology to evaluate, rank, and prioritize corrosion-related failure modes. The integration of these approaches enabled the identification of important corrosion risks and supported the development of a structured, risk-based decision-making framework aligned with industry practices.

2.2 Locale of the Study

The study was conducted in selected oil and gas facilities located in Batangas Province, Philippines. Batangas serves as a major hub for petroleum refining, storage, and distribution and plays a significant role in the country's energy infrastructure. The province's coastal setting, humid tropical climate, and varied soil conditions expose pipeline systems to aggressive environmental factors that accelerate corrosion. These characteristics make Batangas an appropriate locale for examining corrosion risks and evaluating corrosion control strategies under real operational and environmental conditions.

2.3 Respondents of the Study

The respondents consisted of field engineers, maintenance personnel, corrosion specialists, and technical staff from oil and gas companies operating pipeline systems in Batangas Province. These respondents were selected due to their direct involvement in pipeline operation, inspection, maintenance, and corrosion management. Their technical knowledge and operational experience provided essential insights into corrosion mechanisms, historical failures, and the effectiveness of existing corrosion control practices.

2.4 Sample and Sampling Procedure

The study involved six participating oil and gas companies with operational pipeline systems in Batangas Province. A purposive sampling technique was used to select respondents who were directly responsible for pipeline integrity and corrosion control. This approach ensured that the data collected reflected practical, site-specific experiences rather than generalized assumptions. The responses from the six companies were consolidated to allow comparative analysis while maintaining confidentiality across participating facilities.

2.5 Research Instrument

The primary research instruments included structured interview questionnaires, key informant interview guides, and site observation checklists. These instruments were designed to gather data on environmental conditions, operational parameters, corrosion history, and existing corrosion control measures. Secondary instruments included company maintenance records, internal technical reports, and published literature on corrosion management standards. The study was guided by standards such as ISO 23222:2020 - Corrosion Control Engineering Life Cycle, SP21430-2019 - Standard Framework for Establishing Corrosion Management Systems, ISO 12944, ISO 21809-1, NACE SP0169, ISO 15589-1, and ISO 13623, which provided structured criteria for evaluating corrosion risks and control strategies.

2.6 Data Gathering Procedure

Data collection involved both primary and secondary sources. Secondary data were obtained through a review of maintenance records, internal reports, and relevant literature on corrosion management practices and standards. These sources provided background information on pipeline operating conditions, historical corrosion issues, and commonly applied mitigation measures. Primary data were gathered through structured interviews, key informant interviews, and site visits conducted at selected oil and gas depots in Batangas Province. Site visits were used to observe pipeline conditions and document visible signs of corrosion, leakage, and environmental exposure such as soil composition, humidity, and temperature. Interviews with engineers, technical and maintenance personnel were conducted separately for each company to comply with confidentiality requirements and to encourage accurate reporting of technical information. No direct field testing or corrosion rate measurements were performed; instead, observations, photographs, and detailed notes were used to supplement interview data. Following data collection, the Failure Mode and Effects Analysis (FMEA) methodology was applied to identify corrosion-related failure modes, analyze their causes and effects, and assess their likelihood, severity, and detectability. Responses from the six companies were statistically treated to compute representative values for analysis.

2.7 Data Analysis Techniques

Data analysis was centered on the application of the Failure Mode and Effects Analysis (FMEA) methodology to evaluate corrosion risks in pipeline systems. Qualitative data from interviews, observations, and document reviews were categorized to identify environmental and operational factors contributing to corrosion. These factors served as the basis for defining corrosion-related failure modes. For each identified failure mode, numerical ratings were assigned for likelihood of occurrence, severity of impact, and detectability based on expert judgment and field observations. To generate representative scores across facilities, the arithmetic mean of the ratings provided by the six participating companies was calculated. The standard deviation was also computed to measure variability in expert assessments and operational conditions. High variability indicated the need for site-specific verification prior to implementing corrosion control measures. The mean values for severity, occurrence, and detectability were used to calculate the Risk Priority Number (RPN) for each failure mode. The resulting RPN values were used to rank and prioritize corrosion risks, while standard deviation values supported interpretation by identifying risks with inconsistent conditions across sites. Failure modes with high RPN values were subjected to further evaluation to assess the effectiveness of existing corrosion control practices, whereas failure modes exhibiting high variability were flagged for site-specific verification prior to the selection of control measures. An analysis was then conducted to evaluate corrosion control strategies implemented with a structured Corrosion Control Management System (CCMS). Strategies were assessed based on cost-effectiveness, operational efficiency, and environmental sustainability. The analytical results formed the basis for developing a decision-making framework and formulating practical corrosion control recommendations. Throughout the analysis, guidance from ISO 23222:2020, SP21430-2019, ISO 12944, ISO 21809-1, NACE SP0169, ISO 15589-1, ISO 13623, and SP21430-2018 was used to ensure alignment with recognized industry best practices.

3. Results and Discussion

3.1 Environmental and Operational Factors Contributing to Pipeline Corrosion

3.1.1 Coastal Exposure

Pipelines located near coastal areas in Batangas were found to experience accelerated external corrosion due to salt-laden air and high humidity. Field observations revealed early coating degradation, surface rusting, and wall thinning in exposed pipeline segments, even where direct seawater contact was absent. These conditions are consistent with high atmospheric corrosivity classifications (C4–C5) under ISO 9223, reflecting aggressive chloride deposition and persistent moisture films on metal surfaces. The findings confirm that coastal exposure significantly increases corrosion risk by promoting electrochemical reactions through chloride accumulation and moisture retention. The observed coating failures align with ISO 9223 classifications and emphasize the need for effective protective systems in coastal environments such as Batangas. The results reinforce the importance of enhanced coatings and corrosion protection strategies for pipelines exposed to marine atmospheres.

3.1.2 Soil Composition

Buried pipelines in clay-rich, acidic, and low-resistivity soils were associated with higher occurrences of pitting corrosion and microbiologically influenced corrosion (MIC). Interviewed engineers from Companies A–F reported accelerated metal loss, coating delamination, and frequent maintenance requirements in pipeline sections exposed to wet, chloride-bearing, and acidic soils, particularly where soil resistivity fell below 2,000 ohm-cm. These findings are consistent with ISO 15589-1 and NACE SP0169, which emphasize soil resistivity, pH, moisture, and chloride content as significant determinants of buried pipeline corrosion. The presence of sulfate-reducing bacteria in such environments explains the observed localized metal loss and deep pitting, emphasizing the need for soil assessment, improved coatings, and effective cathodic protection systems.

3.1.3 Humid Tropical Climate

The warm and humid tropical climate of Batangas, characterized by relative humidity frequently exceeding 70–75% and temperatures between 25–35 °C, was observed to accelerate uniform and crevice corrosion. Aboveground pipelines exposed to outdoor conditions exhibited coating blistering, surface rust, and moisture-induced degradation, consistent with extended Time of Wetness (TOW) conditions. The results support established corrosion principles indicating that prolonged TOW significantly increases corrosion rates in tropical environments. Similar findings reported in humid coastal regions such as Cuba and the Yucatán Peninsula further validate the observed relationship between high humidity and accelerated metal loss, highlighting the necessity for weather-resistant coatings and regular inspection in such climates.

3.2 Operational Factors Affecting Pipeline Corrosion

3.2.1 Pipeline Pressure

Pipeline operating pressures ranging from approximately 100 psi to 3,000 psi were associated with distinct corrosion mechanisms. Low-pressure lines showed water accumulation and microbial activity, moderate-pressure systems exhibited internal corrosion due to dissolved gases and water, and high-pressure pipelines experienced erosion–corrosion, particularly at bends and elbows. Pressure fluctuations were also linked to stress corrosion cracking and pressure-induced cracking. These findings align with API RP 1110 and NACE SP0106, which identify pressure, flow velocity, and pressure variability as essential contributors to internal corrosion and mechanical degradation. The observed wall thinning and cracking highlight the importance of pressure control, monitoring, and system design optimization to reduce corrosion-related failure risks.

3.2.2 Pipeline Temperature

Most pipelines operated within moderate temperature ranges (30–60 °C), where uniform corrosion and localized pitting were prevalent. High-temperature operations (60–100 °C), particularly in heavy fuel oil handling, were associated with increased corrosion rates and thermal stress, while thermal cycling contributed to coating degradation and crack initiation. The influence of temperature on corrosion behavior is well established, with elevated temperatures accelerating electrochemical reactions and weakening protective films. The findings emphasize the need for insulation, temperature monitoring, and heat-resistant coatings, consistent with documented corrosion mechanisms associated with thermal stress and cycling.

3.2.3 Composition of Transported Fluids

The presence of water, dissolved gases such as H_2S and CO_2, chlorides, and microbial contaminants significantly contributed to internal corrosion. Pipelines transporting water-bearing or stagnant fluids exhibited higher risks of MIC, pitting, and uniform wall thinning, particularly where sulfate-reducing bacteria were present. These results confirm that fluid composition is a dominant driver of internal corrosion. The interaction of water with acidic gases and chlorides creates aggressive corrosive environments, while microbial activity accelerates localized damage. The findings support the application of corrosion inhibitors, biocides, dehydration, and fluid monitoring as outlined in ISO 23222:2020.

3.3 FMEA-Based Corrosion Risk Assessment

The FMEA identified ten major corrosion-related failure modes affecting pipelines in Batangas. Microbial corrosion ranked as the highest risk (RPN 463.58), followed by internal corrosion (RPN 411.61), soil-side corrosion (RPN 351.04), and late corrosion detection (RPN 315.67). Moderate-risk failure modes included pressure-induced cracking, external corrosion, high-pressure corrosion, thermal fatigue corrosion, high-humidity corrosion, and high-temperature corrosion. The prioritization demonstrates that internal and microbiological corrosion pose the greatest threats due to their rapid progression and low detectability. The results validate the use of FMEA as an effective tool for systematically ranking corrosion risks and guiding targeted mitigation strategies, emphasizing proactive intervention for high-RPN failure modes.

3.4 Variability Analysis and Site-Specific Risk Considerations

Standard deviation analysis revealed consistent risk evaluations for external corrosion, soil-side corrosion, internal corrosion, high-humidity corrosion, and microbial corrosion. In contrast, corrosion due to high pressure, pressure-induced cracking, thermal fatigue corrosion, high-temperature corrosion, and late corrosion detection showed high variability across facilities. High variability reflects differences in operating conditions, inspection practices, and environmental exposure among companies. These findings justify the requirement for site-specific verification when SD values exceed 1.5, ensuring that corrosion control measures are appropriately adapted rather than uniformly applied.

3.5 Development of the Corrosion Control Management System (CCMS)

A structured CCMS was developed by integrating FMEA results, RPN-based risk classification, variability assessment, and corrosion control selection aligned with API 580 and ISO 31010. The framework links risk prioritization to actionable controls, responsibility assignment, and continuous feedback. The CCMS translates analytical risk assessment into practical decision-making, ensuring accountability and systematic corrosion management. Its alignment with ISO 23222:2020 and NACE SP21430-2019 supports lifecycle-based corrosion control and continuous improvement.

3.6 Evaluation of the Proposed CCMS

The proposed CCMS is projected to reduce annual corrosion-related maintenance costs by 15–30%, decrease unplanned downtime by 20–35%, and lower the likelihood of corrosion-related environmental incidents by 25–40%. Improvements were also noted in maintenance planning, inspection effectiveness, and resource utilization. These outcomes demonstrate that a risk-based, preventive corrosion management system enhances cost-effectiveness, operational efficiency, and environmental sustainability. By prioritizing high-risk failure modes and integrating monitoring and feedback, the CCMS provides a robust and adaptable framework for improving pipeline integrity in oil and gas terminal operations.

4. Conclusion & Recommendations

This study demonstrated that pipeline corrosion in oil and gas facilities in Batangas Province is strongly influenced by interacting environmental and operational factors, including coastal exposure, soil composition, humid tropical climate, operating pressure, temperature, and transported fluid composition. Through field observations, expert interviews, and the application of Failure Mode and Effects Analysis (FMEA), ten major corrosion-related failure modes were identified and systematically prioritized based on Risk Priority Numbers. Microbiologically influenced corrosion, internal corrosion, soil-side corrosion, and delayed corrosion detection emerged as the most significant risks due to their severity, frequency, and limited detectability. The integration of variability analysis further highlighted the importance of site-specific assessment for corrosion mechanisms influenced by operational differences. Based on these findings, a structured Corrosion Control Management System (CCMS) was developed, aligning risk prioritization with international standards to support cost-effective, operationally efficient, and environmentally sustainable pipeline integrity management.

Based on the findings, it is recommended that oil and gas companies operating pipelines in Batangas adopt the proposed Corrosion Control Management System (CCMS) as a structured, risk-based approach to corrosion management. Priority should be given to high-risk failure modes identified through FMEA, particularly microbial corrosion, internal corrosion, soil-side corrosion, and delayed detection, using targeted mitigation measures such as chemical treatment, improved coatings, cathodic protection, operational controls, and enhanced inspection programs. Failure modes exhibiting high variability should undergo site-specific verification before implementation to ensure alignment with actual operating conditions. Continuous monitoring, regular reassessment of Risk Priority Numbers, and integration of corrosion control actions into formal work order systems are recommended to sustain effectiveness, reduce unplanned downtime, optimize maintenance costs, and minimize environmental risks while ensuring compliance with recognized international corrosion management standards.

Compliance with ethical standards

This study was conducted using a mixed-method research design involving site observations, structured interviews, and document reviews focused on corrosion risks and management practices in oil and gas pipeline systems. The study did not involve experimental interventions, medical procedures, or the collection of sensitive personal data.

Acknowledgements

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Conflict of interest statement

The authors declare that there is no conflict of interest associated with this study.

Statement of ethical approval

Ethical approval by an institutional review board or ethics committee was not stated in the study.

Statement of informed consent

Informed consent procedures were not explicitly stated; however, participation in interviews was limited to professional personnel providing technical and operational information within their respective organizational roles, and the confidentiality of company-specific data was maintained.

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