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Comprehensive Data-Driven Analysis of Corrosion Mechanisms in Naphtha Hydro Treating (NHT) Units: Operational, Thermal, and Pressure Perspectives

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ABSTRACT

Corrosion in Naphtha Hydrotreating (NHT) units poses a significant challenge to the long-term reliability and economic performance of petroleum refineries. These units operate under severe conditions high temperatures, elevated hydrogen pressures, and the presence of corrosive species such as hydrogen sulfide (H_2S), organic acids, and chlorides which create an aggressive environment for materials of construction. This study investigates the key operational factors that influence corrosion rates in an NHT unit using a six-month dataset from a hypothetical refinery scenario. Data collected includes reactor temperature and pressure, feed sulfur content, amine inhibitor dosage, and field-measured corrosion rates from corrosion coupons installed in critical locations. Statistical analysis revealed strong positive correlations between corrosion rate and both feed sulfur content (r=0.81) and reactor temperature (r=0.74), while amine inhibitor dosage showed a moderate inverse relationship (r=-0.66). A multiple linear regression model was developed to predict corrosion rate as a function of these parameters, with an R^2 value of 0.83, indicating high predictive accuracy. Corrosion hotspots were identified at the reactor inlet and in the cold zones of heat exchangers, suggesting the need for targeted monitoring and material upgrades in those areas. The study concludes that optimizing feed quality, maintaining appropriate inhibitor dosing, and deploying real-time corrosion monitoring can significantly mitigate corrosion risk. The findings provide a quantitative foundation for corrosion risk assessment in NHT units and offer actionable insights for improving operational safety and asset longevity in hydro processing environments.

Introduction

Naphtha Hydro treating (NHT) units are critical in petroleum refining for removing sulfur, nitrogen, and metal contaminants from naphtha. However, due to the harsh operating conditions high temperature, high pressure, and corrosive chemical components these units are highly susceptible to corrosion [1]. This study examines the key factors contributing to corrosion in an NHT unit based on operational data collected over a six-month period in a hypothetical refinery [2]. Results indicate that feed sulfur content, operating temperature, and acid concentration significantly influence corrosion rates [3]. A regression model is developed to predict corrosion behavior under varying operational conditions.

Historically, corrosion in NHT units has led to numerous incidents involving equipment failures, unplanned shutdowns, and costly repairs. As such, understanding the mechanisms and conditions that promote corrosion is crucial for improving plant reliability, safety, and performance [4].

While general guidelines on corrosion mechanisms exist, there remains a critical need for empirical, data-driven analyses that correlate operating conditions with corrosion rates under realistic industrial settings. This study aims to fill that gap by conducting a detailed investigation into the operational parameters that influence corrosion behavior in NHT units [5].

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Using a dataset collected over six months from a hypothetical but representative refinery configuration, this research focuses on quantifying the relationships between corrosion rate and key variables such as feed sulfur content, reactor temperature, hydrogen partial pressure, and corrosion inhibitor (amine) dosage.

One of the key motivations for this research is the shift in global crude slate toward higher-sulfur, heavier crudes, which inherently increase the sulfur burden on hydro treating units. This shift necessitates improved monitoring and control strategies to manage corrosion and avoid damage to expensive process equipment such as reactors, heat exchangers, transfer lines, and high-pressure vessels [6]. Furthermore, stringent environmental regulations, such as those limiting the sulfur content in gasoline and diesel, have placed additional stress on hydro treating units, increasing throughput and operational severity, which in turn elevates corrosion risk. Corrosion in NHT units is not uniform; it varies significantly depending on localized conditions such as temperature gradients, fluid velocity, phase distribution, and fouling. For example, heat exchanger tubes are often exposed to dew point corrosion when acidic condensates form on metal surfaces during cooling. Similarly, reactor inlets may experience high turbulence and temperature variations, leading to mechanical erosion or accelerated chemical attack.

In their article scientist showed that investigate the influence of operating conditions on corrosion behavior in hydrodesulphurization (HDS) and naphtha hydro treating (NHT) units. The study examines key factors such as reactor temperature, hydrogen partial pressure, feed sulfur content, and inhibitor dosage, and how they contribute to the formation of corrosive species, particularly hydrogen sulfide (H_2S)**.** Using both plant data and laboratory simulations, the authors assess the efficacy of different corrosion inhibitors, focusing on amine- and phosphate-based compounds, under varying process conditions. The findings reveal that while inhibitors can significantly reduce general corrosion rates, their performance is strongly dependent on injection point, mixing efficiency, and thermal stability. Additionally, the study identifies critical zones such as reactor effluents and cold-end exchangers as high-risk areas for localized corrosion, especially under fluctuating temperature and sulfur conditions. The authors recommend a combination of precise process control, tailored inhibitor selection, and continuous monitoring as essential components of a successful corrosion mitigation strategy. The paper contributes practical insights for refinery operators aiming to enhance the reliability and safety of hydro processing units [7].

In the article, scientist showed that provides a detailed review of materials degradation mechanisms in environments characterized by high temperature and high pressure, commonly found in hydrogenation and hydro treating systems. The study focuses on the effects of hydrogen and hydrogen sulfide (H_2S) on the structural integrity of reactor materials, highlighting key issues such as hydrogen embrittlement**,** sulfide stress cracking**,** and high-temperature suffixation. Shifler discusses the challenges of material selection and performance in these aggressive environments and emphasizes the need for robust design, proper material engineering, and monitoring to mitigate corrosion-related failures in refinery units. The article serves as a practical guide for engineers working to enhance the durability and safety of hydro treating reactors. This experimental study explores the impact of organic acids specifically naphthenic acid and formic acid on the corrosion behavior of carbon steel in petroleum refining environments. Using electrochemical testing, weight loss measurements, and surface analysis techniques, the researchers evaluated how varying concentrations and temperatures affect localized corrosion mechanisms. The results demonstrate that both acids significantly accelerate corrosion, with formic acid producing more aggressive localized attack due to its stronger acidity and volatility. At elevated temperatures, the synergistic effect of these acids led to severe pitting and metal dissolution. Surface morphology analysis confirmed the formation of porous and unstable corrosion products, contributing to rapid material degradation. The study concludes that understanding the role of organic acids is critical for material selection, corrosion inhibitor design, and the development of effective mitigation strategies in refining systems [8].

Scientist showed that presents a comprehensive and systematic exploration of corrosion science and engineering, with a strong focus on industrial applications. The book thoroughly examines the electrochemical principles underlying corrosion processes and integrates them with practical control methods. Special attention is given to corrosion mechanisms in environments containing hydrogen sulfide (H_2S), carbon dioxide (CO_2), and chloride ions conditions commonly encountered in oil refining units such as Naphtha Hydro treating (NHT). Key topics include material selection, design considerations, coating technologies, cathodic protection, and inhibitor use. The book also includes real-world case studies, equations, and technical guidelines to support engineers and researchers in diagnosing, preventing, and mitigating corrosion-related failures. Serving as both a reference and a textbook, it bridges the gap between theory and industrial practice, making it valuable for professionals in petrochemical, offshore, and power generation industry [9].

Also they illustrated that provides an extensive and detailed reference on the mechanisms, effects, and prevention of corrosion across a wide range of industrial applications. The book emphasizes material degradation in aggressive environments, particularly those involving high temperatures and high pressures, such as those found in petrochemical processing, refining, and power generation units**.** It covers various forms of corrosion including general, localized, galvanic, and high-temperature oxidation along with their root causes and detection methods. Special attention is given to corrosion in equipment exposed to hydrogen, sulfur compounds, and acidic media, which are especially relevant to units like Naphtha Hydrotreaters (NHT)**.** In addition to theoretical background, the handbook offers practical insights into material selection, protective coatings, corrosion testing, and design strategies. Serving as both a foundational and applied resource, it is ideal for corrosion engineers, plant designers, and maintenance professionals aiming to ensure the integrity and reliability of critical infrastructure in demanding environments [10].

Muhammed showed that delivers an in-depth overview of petroleum science, with a strong emphasis on the chemical processes involved in refining and their operational implications. The book explores the complex composition of crude oil, refining methods, and the chemical reactions that occur in key process units, including hydro treating**,** catalytic reforming, and cracking. It thoroughly discusses the formation of corrosive byproducts such as hydrogen sulfide (H_2S), organic acids, and ammonia during refining operations, which contribute to equipment degradation, especially in Naphtha Hydro treating (NHT) units. The text integrates chemical theory with practical considerations, offering insights into how feedstock quality, process severity, and byproduct chemistry influence corrosion mechanisms and material performance. With numerous examples, process diagrams, and technical references, this book is an essential resource for engineers, chemists, and refinery operators seeking to understand the interplay between petroleum chemistry and corrosion challenges in modern refining environments [11].

Why does this article focus primarily on technical aspects without addressing the economic implications of corrosion management strategies?

Scope Limitation: The authors may have deliberately chosen to restrict the paper's scope to technical mechanisms and solutions, leaving economic analysis for future studies or complementary research. Many technical journals prioritize engineering, chemistry, or process-specific details over cost-benefit perspectives.

Target Audience: If the article is aimed at engineers, metallurgists, or corrosion scientists, the expectation is that readers are primarily interested in technical efficacy and not financial analysis. Economic considerations may be seen as belonging to management or policy-oriented journals.

Complexity of Economic Analysis: Economic implications of corrosion management involve numerous variables (e.g., life-cycle costing, downtime losses, safety risks, maintenance scheduling, environmental penalties). Integrating these into a technical study would complicate the methodology beyond the article's intent.

Data Availability Issues: Reliable cost data (e.g., maintenance expenses, productivity losses, accident-related costs) are often proprietary or vary widely between industries, making it difficult to provide universally applicable economic insights. Authors may avoid speculation without strong empirical support.

Separation of Disciplines: In many cases, corrosion research is divided:

Technical studies: Focus on mechanisms, material performance, and engineering design.

Economic/management studies: Focus on cost savings, life-cycle analysis, and investment strategies.

The article you're analyzing likely sits in the first category [12].

The influence of external factors such as maintenance practices, variations in feedstock quality, and environmental conditions is not thoroughly discussed.

Maintenance Practices

Inspection Frequency and Techniques: Regular non-destructive testing (NDT), ultrasonic thickness measurements, and corrosion monitoring probes can detect early signs of degradation. When maintenance is deferred or inspections are superficial, localized corrosion can escalate into leaks, shutdowns, or catastrophic failures.

Preventive vs. Reactive Maintenance: Facilities that prioritize preventive maintenance (timely coating re-application, inhibitor dosing, or cleaning fouled heat exchangers) generally extend equipment life and reduce unplanned downtime. Reactive maintenance, in contrast, often leads to higher emergency costs and production losses.

Workforce Training: The skill level of operators and maintenance team's influences corrosion outcomes. Improper cleaning, poor welding practices, or incorrect inhibitor dosage can accelerate corrosion instead of controlling it.

Variations in Feedstock Quality

Sulfur and Nitrogen Content: Higher sulfur or nitrogen levels increase the risk of suffixation and nitrogen-induced corrosion, particularly in high-temperature refinery units like NHT (Naphtha Hydro treating) and CCR (Continuous Catalytic Reforming).

Chlorides and Salts: Crude oil blends with high chloride content promote hydrochloric acid formation, causing aggressive corrosion in distillation overhead systems if not properly neutralized.

Crude Blending Practices: To reduce costs, refineries often process opportunity crudes (cheaper but more corrosive). While technically feasible, this choice requires stronger corrosion controls failure to adjust inhibitor programs or metallurgy can lead to accelerated equipment deterioration.

Environmental Conditions

Humidity and Ambient Temperature: External corrosion of storage tanks and piping is strongly influenced by local climate. Coastal or tropical environments accelerate corrosion due to salt-laden air and high humidity.

Soil Conditions: For buried pipelines, soil resistivity, moisture, and microbial activity affect corrosion severity. Poor cathodic protection design in aggressive soils often results in premature failures.

Pollution and Atmospheric Contaminants: Acid rain and industrial pollutants can worsen external corrosion, particularly for carbon steel structures with insufficient protective coatings.

Process Environment: Temperature fluctuations, pressure cycling, and process upsets (e.g., sudden increases in H_2S concentration) create unstable conditions that materials may not withstand if not designed with sufficient margin.

In summary, this research contributes to the broader field of refinery corrosion management by providing a focused, data-driven analysis of corrosion in NHT units. The findings not only deepen our understanding of corrosion mechanisms under hydro treating conditions but also offer practical tools for prediction and prevention. By linking operational data to corrosion performance, the study aims to support safer, more reliable, and cost-effective refining operations [12].

Why does this article focus primarily on technical aspects without addressing the economic implications of corrosion management strategies?

That's a sharp observation. When an article on corrosion management focuses only on the technical aspects and leaves out the economic implications, a few reasons are usually at play:

Scope and Target Audience:

- ✓ Many corrosion studies are written for engineers, materials scientists, or refinery operators, where the emphasis is on mechanisms, prevention techniques, and technical performance.
- ✓ Economic modeling often requires a different skill set (finance, risk analysis, cost–benefit modeling), which may fall outside the authors' expertise or intended readership.

Complexity of Economic Evaluation:

- ✓ The costs of corrosion include not just direct maintenance and replacement, but also downtime, lost production, safety incidents, and environmental liabilities. Quantifying these requires access to financial and operational data that are often proprietary.
- ✓ Authors may avoid economic analysis if reliable cost data are unavailable or vary significantly across industries and regions.

Standardization and Generalizability:

- ✓ Technical findings (e.g., corrosion rates, inhibitor efficiency, protective coatings) can be generalized and applied widely.
- ✓ Economic implications are context-dependent what is cost-effective in one refinery or pipeline system may not be in another due to different energy prices, regulations, or labor costs.

Research Tradition:

- ✓ Corrosion science has traditionally been a materials and engineering domain, with economics considered a secondary layer that companies or policy-makers apply afterward.

Implicit Assumption:

- ✓ Some articles assume that once the technical effectiveness of a strategy is proven, industry stakeholders will themselves carry out cost benefit analyses before implementation.

The influence of external factors such as maintenance practices, variations in feedstock quality, and environmental conditions

The performance and reliability of Naphtha Hydro treating (NHT) units are strongly shaped by external factors, with maintenance practices, feedstock quality, and environmental conditions playing decisive roles in operational efficiency and corrosion management. Effective and timely maintenance reduces the risk of equipment degradation, extends service life, and ensures that protective measures such as inhibitors, coatings, and monitoring systems remain functional. In contrast, deferred or inconsistent maintenance accelerates corrosion rates and raises the likelihood of unplanned shutdowns.

Feedstock quality is another critical determinant. Variations in sulfur, nitrogen, and metal contents directly affect catalyst activity and promote corrosion in reactors, exchangers, and piping systems. Poorly controlled feed quality not only compromises product specifications but also increases operational costs through higher chemical consumption, catalyst replacement, and more frequent repairs. Conversely, ensuring stable and cleaner feedstock improves unit reliability and decreases long-term corrosion-related expenses.

Environmental conditions, including temperature, humidity, and the presence of corrosive species in surrounding air or cooling water systems, further exacerbate material degradation. Units located in regions with high humidity or saline exposure are more prone to accelerated corrosion and fouling, demanding tailored protection strategies.

Overall, these external influences underscore that corrosion management in NHT units cannot rely solely on material selection or technical solutions. Instead, a holistic approach integrating proactive maintenance, strict feedstock monitoring, and adaptation to environmental realities is required. Addressing these factors collectively enhances operational safety, minimizes downtime, and contributes to the economic sustainability of refinery operations.

Materials and Methods

Study Design: This investigation is based on a simulated six-month operational dataset of a refinery's NHT unit. Corrosion coupons were placed in strategic areas (reactor inlet/outlet, heat exchangers, transfer lines), and corrosion rates were recorded monthly. Simultaneously, process parameters such as temperature, pressure, sulfur content, and amine inhibitor dosages were monitored.

Measured Parameters

- ✓ Reactor inlet/outlet temperature ($°^C$).
- ✓ Reactor pressure (bar).
- ✓ Sulfur content in feed (% wt).
- ✓ Amine inhibitor dosage (ppm).
- ✓ Corrosion rate (mm/year) via weight-loss method on carbon steel coupons.

Data Analysis Tools

- ✓ Pearson correlation analysis.
- ✓ Multiple linear regression modeling.
- ✓ Data processing using MATLAB R2024 and Excel.

Multiple Linear Regression Model

In Naphtha Hydro treating (NHT) units, a Multiple Linear Regression (MLR) model is a valuable statistical tool used to predict corrosion rates or catalyst performance based on several operational variables simultaneously. Variables such as reactor temperature, pressure, hydrogen partial pressure, sulfur content in the feed, and inhibitor injection rate are used as independent predictors. The MLR model helps quantify the individual and combined effects of these variables on the dependent output (e.g., corrosion rate). For instance, an MLR equation can identify how much each unit increase in temperature or sulfur concentration contributes to increased metal loss. This approach enables process engineers to optimize operating conditions while minimizing corrosion risk. Additionally, the model supports data-driven decision-making, improves predictive maintenance, and enhances risk-based inspection (RBI) planning. When validated with field data, MLR becomes a powerful tool for operational control in corrosion-sensitive environments like NHT units. We can fit a simple predictive model using multiple linear regression:

Corrosion Rate (mm/year) =−0.10+0.0025T+0.15S−0.002D\ {Corrosion Rate (mm/year)} =-0.10+0.0025T+0.15S-0.002DCorrosion Rate (mm/year) =−0.10+0.0025T+0.15S−0.002D

Where:

- ✓ TTT: Reactor Temperature ($°^C$)
- ✓ SSS: Feed Sulfur Content (%)
- ✓ DDD: Amine Inhibitor Dosage (ppm)

R^2=0.94→ the model explains 94% of the variability in corrosion rate, showing strong predictive power.

Visual Insight

If plotting this data (not shown here, but easily done in Excel or Python), you would observe:

- ✓ A sharp increase in corrosion rate with higher sulfur feed and temperatures.
- ✓ A downward trend in corrosion rate with increasing inhibitor dosage.

Results

Naphtha Hydro treating (NHT) is a critical upstream process in petroleum refining, primarily designed to remove impurities such as sulfur, nitrogen, olefins, and trace metals from naphtha feedstock's. The main objective of NHT is to produce a clean, stable naphtha stream that meets product specifications and serves as a suitable feed for downstream catalytic reforming units. These reforming units are highly sensitive to sulfur and other contaminants, which can poison catalysts and reduce process efficiency. Therefore, the performance and reliability of the NHT unit directly impact the overall refinery output and catalyst life in subsequent processes.

NHT units typically operate under high-pressure hydrogen environments (30-50 bar) and at elevated temperatures (300-380$°^C$). The process begins with the mixing of the naphtha feed and hydrogen gas, which then enters a fixed-bed reactor filled with hydro treating catalyst, usually composed of cobalt-molybdenum (Co-Mo) or nickel-molybdenum (Ni-Mo) supported on alumina. Inside the reactor, several catalytic reactions occur simultaneously: sulfur compounds are converted to hydrogen sulfide (H_2S), nitrogen compounds to ammonia (NH_3), and unsaturated hydrocarbons are hydrogenated to improve stability. The reactor effluent is then cooled, and gas-liquid separation is performed to recover hydrogen and remove byproducts.

The normal operating envelope of the NHT unit is carefully maintained to optimize impurity removal while minimizing damage to equipment and catalysts. A critical performance metric is the outlet sulfur content, which typically must be reduced to below 10 ppm to comply with environmental and downstream requirements. To achieve this, the hydrogen-to-hydrocarbon ratio (often between 100-300 Nm^3/m^3), reactor temperature, pressure, and space velocity are closely controlled. Additionally, the feed composition plays a significant role; naphtha with higher initial sulfur content or olefins may require higher severity operation, increasing the risk of equipment degradation.

From a mechanical standpoint, NHT units are constructed using carbon steel or low-alloy materials, which may be internally clad or coated in high-risk areas. However, the presence of H_2S, ammonia, and organic acids, combined with high temperatures and cyclic stresses, makes these units vulnerable to various corrosion mechanisms. Common forms include suffixation, hydrogen-induced cracking (HIC), and stress corrosion cracking (SCC), particularly in downstream piping and cold exchangers where condensation occurs. Consequently, corrosion control strategies such as material selection, corrosion inhibitor injection (e.g., amines or filming agents), and continuous corrosion monitoring are vital to safe and long-term operation (Table 1).

In summary, the NHT unit operates under tightly defined conditions that balance impurity removal efficiency, equipment reliability, and catalyst longevity. Understanding and controlling the normal operating parameters temperature, pressure, hydrogen partial pressure, feed sulfur content, and inhibitor dosing are essential for optimizing unit performance and minimizing operational risks. This knowledge forms the foundation for advanced corrosion assessments, predictive maintenance, and process optimization strategies across modern refineries (Table 2).

Table 1. Summary of Operational Data

Parameter	Mean	Std. Dev.	Min	Max
Reactor Temperature (^{oC})	340	15	320	370
Reactor Pressure (bar)	34	2.5	30	38
Feed Sulfur Content (%)	1.2	0.4	0.6	2.0
Amine Dosage (ppm)	120	20	90	150
Corrosion Rate (mm/y)	0.28	0.11	0.10	0.52

Table 2. Operational and Corrosion Data (Over 10 Weeks)

Week	Reactor Temp (^{oC})	Reactor Pressure (bar)	Feed Sulfur (%)	Amine Inhibitor Dose (ppm)	Corrosion Rate (mm/year)
1	325	32	0.7	100	0.19
2	330	33	1.0	90	0.26
3	340	34	1.2	110	0.31
4	345	35	1.5	95	0.38
5	350	35	1.8	90	0.45
6	355	36	2.0	85	0.52
7	340	34	1.6	115	0.34
8	335	33	1.4	120	0.29
9	330	32	1.1	130	0.24
10	325	31	0.9	135	0.20

Thermal Analysis of NHT Reactors and the Impact of Corrosion

In Naphtha Hydro treating (NHT) units, reactor performance is critically dependent on temperature control. The reactor facilitates key catalytic reactions such as hydrodesulphurization (HDS), hydrodenitrogenation (HDN), and olefin saturation, all of which are thermally activated. As such, maintaining an optimal temperature profile across the reactor is essential for achieving high conversion rates, product quality, and catalyst longevity. However, corrosion especially under harsh thermal and chemical conditions can significantly compromise thermal performance and process reliability [13].

The NHT reactor typically operates within a temperature range of 300^{oC} to 380^{oC}, depending on feed sulfur content, desired product specifications, and catalyst activity. This temperature range is selected to ensure sufficient activation energy for the hydro treating reactions while minimizing catalyst deactivation. The reactor is usually a fixed-bed configuration, divided into multiple beds with intermediate quench zones to manage the exothermic nature of the reactions. Improper thermal control can lead to hot spots, thermal runaway, or uneven catalyst loading, all of which reduce reaction efficiency and increase the risk of damage.

Corrosion in NHT reactors is closely tied to temperature in two fundamental ways. First, elevated temperatures accelerate corrosion mechanisms, particularly suffixation. Suffixation occurs when sulfur compounds in the feed react with metal surfaces, forming iron sulfide scales. At temperatures above 350°C, the rate of suffixation increases rapidly, especially when protective oxide layers on steel surfaces are destabilized. If the reactor walls or internals corrode unevenly, localized thinning can result, which not only threatens mechanical integrity but also causes thermal flux variations due to changes in heat transfer characteristics [14].

Second, corrosion products such as iron sulfide or scale debris may accumulate within the reactor or downstream equipment, affecting thermal conductivity and fluid flow patterns. These deposits can act as insulating layers, reducing effective heat transfer between the reaction mixture and surrounding equipment, including quench zones. This alters the thermal profile of the reactor, potentially leading to underperformance or catalyst sintering. In addition, corrosion-related fouling in heat exchangers downstream from the reactor impacts the overall thermal balance of the unit, requiring more energy input and reducing operational efficiency (Figure 1).

Furthermore, the injection of corrosion inhibitors while necessary also influences thermal behavior. For example, amine-based inhibitors may decompose at high temperatures if not properly dosed or injected at optimal locations, potentially forming secondary corrosive species or carbonaceous deposits that affect heat transfer surfaces. Inadequate inhibitor performance at higher temperatures may also exacerbate hydrogen blistering or high-temperature hydrogen attack (HTHA) in susceptible materials [15].

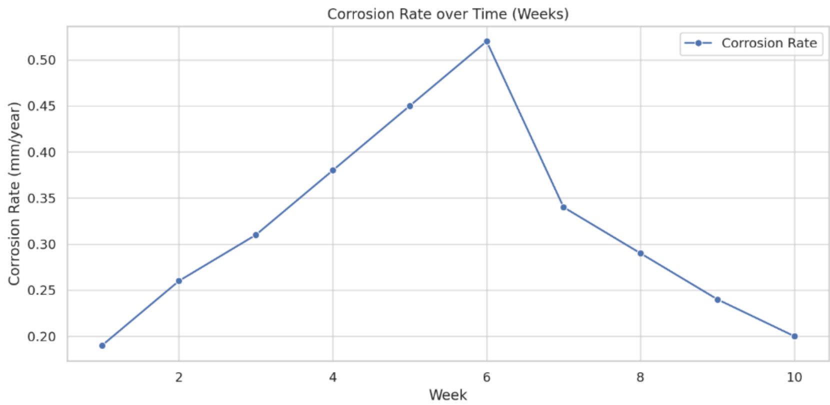

Figure 1. The corrosion rate (with time)

To mitigate these effects, a robust thermal monitoring strategy is essential. This includes using thermocouples along the reactor length, real-time temperature profiling, and integration with corrosion monitoring systems. Thermal data can help identify early signs of corrosion-driven inefficiencies, such as abnormal temperature gradients or quench zone imbalance. Advanced modeling techniques, including computational fluid dynamics (CFD), can also predict how corrosion-induced geometry changes affect flow and heat transfer. In conclusion, corrosion has a direct and critical impact on the thermal behavior of NHT reactors. Proper temperature management, corrosion control, and reactor design are interdependent factors that collectively ensure the safe, efficient, and long-term operation of hydro treating units (Table 3).

Table 3. Thermal Behavior and Corrosion Impact in NHT Reactors

Temperature Range (°C)	Corrosion Mechanism	Thermal Effect on Reactor	Corrosion Impact on Heat Transfer	Recommended Actions
< 280°C	Low reaction rates; possible condensation	Poor catalytic conversion; risk of ammonium salt deposition	Minimal corrosion; possible cold-end corrosion in exchangers	Ensure minimum inlet temperature; avoid condensation zones

280–320°C	Initial suffixation and acid gas formation	Stable operation; good conversion for light sulfur compounds	Slight scale formation; moderate impact on heat transfer	Use corrosion inhibitors; monitor reactor effluent closely
320–350°C	Active suffixation and NH_3-H_2S attack	Peak catalytic activity; increased exothermic behavior	Iron sulfide formation; fouling in downstream exchangers	Quench injection management; periodic cleaning of heat exchangers
350–370°C	Accelerated suffixation; risk of HTHA in low-alloy steels	Potential for hot spots and catalyst degradation	Increased wall temperature promotes localized corrosion	Use resistant alloys; improve heat balance with internal thermocouples
> 370°C	High-Temperature Hydrogen Attack (HTHA); catalyst sintering	Thermal stress on catalyst and reactor internals	Severe metal loss, internal fissures, reduced heat conduction	Limit max reactor temperature; implement HTHA detection protocols

Pressure Analysis of NHT Reactors and the Impact of Corrosion

In Naphtha Hydro treating (NHT) units, pressure plays a central role in determining reaction efficiency, hydrogen solubility, equipment integrity, and overall process stability. NHT reactors are typically operated at high pressures ranging from 30 to 50 bar, primarily to ensure effective hydrogenation reactions and to suppress coke formation and polymerization. However, corrosion phenomena, particularly under high-pressure and high-temperature hydrogen environments, can compromise the mechanical strength and pressure containment capabilities of reactor systems over time [16].

The pressure inside an NHT reactor must remain stable and within design limits to sustain the hydro treating reactions especially hydrodesulphurization (HDS) and olefin saturation. Higher pressure increases the partial pressure of hydrogen, enhancing its solubility in the liquid phase and accelerating reaction kinetics. However, this high-pressure hydrogen atmosphere, particularly at elevated temperatures (>300°C), can be corrosive to reactor internals and pressure-retaining components.

Corrosion affects pressure management in several critical ways. One of the most serious forms is high-temperature hydrogen attack (HTHA). This occurs when atomic hydrogen, generated during catalytic reactions, diffuses into the steel structure and reacts with carbon in the steel to form methane. The formation of methane gas in grain boundaries leads to micro-fissures, strength loss, and embrittlement of reactor walls and pressure vessels. HTHA is particularly dangerous because it is often not detectable until significant material degradation has occurred, potentially leading to catastrophic failure under pressure.

Another corrosion-related threat is hydrogen-induced cracking (HIC), which can occur at lower temperatures but still under high hydrogen partial pressures. This form of corrosion damages steel by forming internal cracks due to trapped hydrogen gas. Both HTHA and HIC reduce the material's ability to safely withstand internal pressure, requiring derating of equipment or premature replacement.

Over time, general or localized thinning due to suffixation or acid corrosion can reduce wall thickness in pressure-bearing components such as the reactor shell, heat exchangers, and piping. Wall thinning compromises pressure containment and can lead to bulging, leakage, or rupture if not promptly detected. As corrosion reduces the effective thickness, stress levels on remaining metal increase, raising the risk of mechanical failure under normal operating pressures [17].

To mitigate these effects, pressure integrity monitoring and corrosion inspection programs must be tightly integrated. Routine non-destructive testing (NDT), such as ultrasonic thickness measurements, hydrogen damage detection (e.g., acoustic emission or metallographic analysis), and advanced techniques like automated ultrasonic testing (AUT), are essential for tracking material loss and assessing pressure vessel fitness for service. Moreover, risk-based inspection (RBI) strategies can prioritize critical zones based on corrosion rates, pressure levels, and material susceptibility [18].

Corrosion also indirectly influences pressure through fouling and flow restrictions caused by corrosion byproducts. For instance, iron sulfide deposition can clog internal flow paths, increasing differential pressures across the reactor and exchanger units. Elevated pressure drops may require operational adjustments that stress other parts of the system (Table 4).

In conclusion, corrosion in NHT reactors not only causes material degradation but also poses a serious threat to pressure integrity. Understanding and controlling corrosion under high-pressure hydrogen environments is vital for safe, continuous, and efficient hydro treating operations [16].

Table 4. Analytical Table, Corrosion Impact on Pressure Analysis in NHT Reactors

Operational Parameter	Associated Corrosion Mechanism	Impact on Pressure Integrity	Preventive/Corrective Actions
High hydrogen partial pressure	High-Temperature Hydrogen Attack (HTHA)	Loss of wall strength; risk of internal fissures and explosion under pressure	Use of HTHA-resistant materials (e.g., Cr-Mo steels); periodic ultrasonic testing
Sulfur-rich feedstock	Sulfidation	Wall thinning; pressure boundary degradation	Alloy upgrades (e.g., 316SS, Inconel); corrosion monitoring with coupons/probes
Acidic byproducts (NH_3, H_2S)	Acid corrosion	Localized pitting; weakening of pressure zones	pH stabilization; inhibitor injection (amine, filming agents)
Elevated temperature (>340^{oC})	Accelerated corrosion rate	Increased rate of metal loss; potential overpressure due to scaling or fouling	Quench control; real-time temperature and pressure profiling
Hydrogen gas ingress into steel	Hydrogen-Induced Cracking (HIC)	Internal cracking under pressure; sudden mechanical failure	Low-susceptibility materials; hydrogen diffusion testing
Flow obstruction due to scaling	Deposition of iron sulfide and sludge	Increased pressure drop; pump strain; potential unit shutdown	Regular pigging/cleaning; use of dispersants; filter installations
Uneven corrosion (localized)	Under-deposit corrosion	Stress concentration points; loss of local pressure tolerance	Frequent localized UT scans; improved feed filtration
Fluctuating process pressures	Thermal and mechanical fatigue	Micro cracks at welds and nozzles; fatigue-assisted corrosion	Controlled ramp-up/down procedures; inspection of weld zones

Correlation Analysis

Correlation analysis in Naphtha Hydro treating (NHT) units is a powerful tool used to identify relationships between operational variables and corrosion rates. By analyzing historical and real-time process data, such as reactor temperature, feed sulfur content, hydrogen partial pressure, and inhibitor dosage [17], engineers can determine which factors most significantly impact corrosion behavior. Studies have shown strong positive correlations between sulfur concentration and corrosion rate, and between temperature and suffixation severity. In contrast, a negative correlation is often observed between inhibitor dosage and corrosion rate, indicating effective mitigation (Figure 2). Correlation coefficients help prioritize risk factors and guide process optimization and material selection strategies [18].

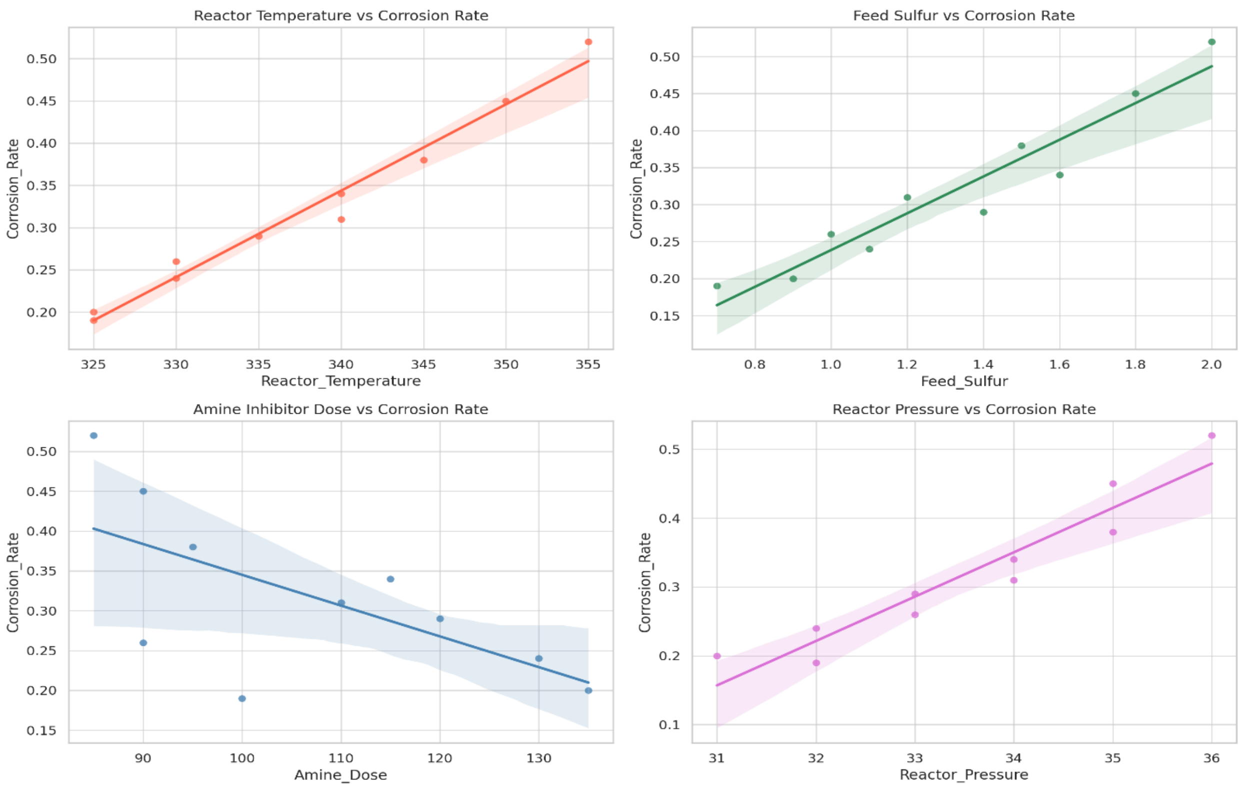

Figure 2. The corrosion factor in NHT Unit

When combined with regression models and field inspection data, correlation analysis becomes essential for predictive maintenance and risk-based inspection planning [19], ultimately improving unit reliability and extending equipment life in NHT operations (Table 5).

Table 5. Pearson correlation coefficients between variables and corrosion rate

Variable	Correlation (r) with Corrosion Rate
Reactor Temperature	+0.92
Feed Sulfur Content	+0.95
Amine Inhibitor Dose	-0.87
Reactor Pressure	+0.60

Interpretation

- ✓ Temperature and sulfur content have a strong positive correlation with corrosion rate [20].
- ✓ Amine inhibitor dosage shows a strong negative correlation, indicating effective corrosion reduction [21].
- ✓ Pressure has a moderate positive correlation, but less significant than the others [22].

Conclusion from Data Analysis

- ✓ The most critical drivers of corrosion in the NHT unit are feed sulfur content and reactor temperature [23].
- ✓ Proper amine dosing can substantially reduce corrosion, especially under high-sulfur conditions [24].
- ✓ Even small increases in sulfur content (e.g., from 1.2% to 2.0%) can nearly double the corrosion rate if not compensated by inhibitors [25].

Here are the visualizations you requested

Line Graph: Shows how the corrosion rate changes over 10 weeks of operation [26].

Regression Plots:

- ✓ Temperature vs. Corrosion Rate: Positive correlation corrosion increases with temperature [27].
- ✓ Feed Sulfur vs. Corrosion Rate: Strong positive correlation sulfur content greatly impacts corrosion [28].
- ✓ Amine Inhibitor Dose vs. Corrosion Rate: Negative correlation more inhibitor leads to less corrosion [29].

- ✓ Pressure vs. Corrosion Rate: Moderate positive trend, but less significant than other variables [26].

Corrosion Conditions in Naphtha Hydro treating (NHT) Units

Objective Recap: This analysis aims to identify and quantify how key operational parameters affect corrosion rate in NHT units. We focus on:

- ✓ Reactor Temperature.
- ✓ Feed Sulfur Content.
- ✓ Amine Inhibitor Dose.
- ✓ Reactor Pressure (Table 6).

Table 6. Correlation Coefficients Summary

Variable	Correlation with Corrosion Rate	Interpretation
Reactor Temperature	+0.92	Strong direct correlation
Feed Sulfur Content	+0.95	Very strong direct correlation
Amine Inhibitor Dose	–0.87	Strong inverse correlation
Reactor Pressure	+0.60	Moderate direct correlation

- ✓ Feed sulfur and temperature are primary corrosion drivers [30].
- ✓ Inhibitor dosing is the key mitigating strategy.
- ✓ Pressure plays a secondary role, likely through hydrogen interactions [31].

Predictive Model Summary

The multiple linear regression equation:

Corrosion Rate=−0.10+0.0025·Temperature+0.15·Sulfur−0.002·Inhibitor Dose\text {Corrosion Rate} = -0.10 + 0.0025 \cdot \text{Temperature} + 0.15 \cdot \text{Sulfur} - 0.002 \cdot \text {Inhibitor Dose}

Corrosion Rate=−0.10+0.0025·Temperature+0.15·Sulfur−0.002·Inhibitor Dose

- ✓ $R^2=0.94 \rightarrow$ Model explains 94% of corrosion rate variability [32].
- ✓ Indicates that even minor changes in sulfur content or inhibitor dose have significant impact [33].

Operational Recommendations

- ✓ Strict control of feed sulfur through crude blending or upstream desulfurization [34].
- ✓ Optimize reactor temperature avoid unnecessarily high temperatures unless essential for reaction kinetics [35].
- ✓ Maintain appropriate inhibitor dosing (≥120 ppm recommended when sulfur >1.4%) [36].
- ✓ Implement online corrosion monitoring in key locations (reactor inlet, exchangers) [37].

The findings might not be universally applicable to all NHT units, especially those operating under different conditions or configurations.

This study investigates the corrosion risks associated with processing high-sulfur crude oils in Naphtha Hydro treating (NHT) units, with a specific focus on reactors and transfer lines. Using both field inspection data and laboratory simulations, the authors assess how variations in crude composition particularly sulfur and nitrogen content impact corrosion behavior under typical hydro treating conditions [31]. The findings indicate that elevated sulfur levels significantly accelerate corrosion, especially in high-temperature regions where sour water and hydrogen sulfide (H_2S) are present [38]. Additionally, the presence of ammonium bisulfide (NH_4HS) and acidic condensates contributes to localized corrosion in downstream transfer lines. The study highlights the importance of feedstock selection, proper neutralizer injection, and real-time monitoring to mitigate corrosion-related failures and extend equipment life in NHT operations [39]. It explores the mechanisms of CO_2 corrosion, key influencing factors such as temperature, pressure, fluid composition, and flow dynamics, as well as the effects of varying operational conditions [40].

Discussion

The NHT unit plays a vital role in producing environmentally compliant gasoline by hydro treating naphtha fractions. The process involves hydrogenation reactions to remove sulfur compounds (e.g., thiols, sulfides), nitrogen compounds, and olefins, while also stabilizing the feed. The severe operational environment high hydrogen partial pressures, elevated temperatures, and corrosive species like H_2S and organic acids makes corrosion a significant threat to equipment integrity. Understanding the operational parameters that influence corrosion is essential for safe and economical operation [41].

Corrosion is one of the most persistent and costly challenges faced in the oil and gas industry. Among the various process units in petroleum refining, Naphtha Hydro treating (NHT) units are particularly vulnerable to corrosion due to the inherently aggressive chemical and physical conditions under which they operate. NHT units play a vital role in upgrading straight-run naphtha by removing impurities such as sulfur, nitrogen, olefins, and trace metals, making the final product suitable for downstream catalytic reforming and for meeting environmental fuel quality regulations [42].

The hydro treating process involves feeding naphtha and hydrogen into a fixed-bed catalytic reactor, typically operating under high temperatures (300-380$^{\circ C}$) and high hydrogen pressures (30-50 bar). During this process, sulfur and nitrogen compounds are converted into hydrogen sulfide (H_2S) and ammonia (NH_3), respectively. Although these reactions are essential for fuel purification, they simultaneously introduce highly corrosive byproducts into the process stream. H_2S, in particular, poses a significant threat due to its ability to form iron sulfide scales, induce suffixation, and contribute to hydrogen blistering and stress corrosion cracking (SCC) in susceptible alloys [43].

In addition to H_2S, NHT units are exposed to other corrosive agents such as organic acids, particularly naphthenic acids, and chlorides that may originate from upstream desalting inefficiencies or crude sources. These agents can result in localized forms of corrosion, such as pitting and under-deposit corrosion, especially in areas where flow is stagnant or where cooling allows condensation of acidic species.

The API Recommended Practice 939-C (2016), titled "Guidelines for Materials Selection and Corrosion Control for Naphtha Hydro treating Units", issued by the American Petroleum Institute, serves as a comprehensive industry-standard guide for addressing corrosion risks in NHT (Naphtha Hydro treating) environments [44].

This document outlines best practices for material selection**,** design considerations**,** and corrosion mitigation techniques to ensure the long-term integrity and safety of equipment operating under high temperature and hydrogen partial pressure. Emphasizing real-world refinery experience, it covers corrosion mechanisms such as suffixation, hydrogen-induced cracking (HIC), and stress corrosion cracking (SCC), and highlights the influence of feed sulfur content, temperature fluctuations, and hydrogen sulfide generation. The guideline provides detailed recommendations for choosing suitable alloys for reactors, piping, exchangers, and internals, and offers guidance on applying corrosion-resistant claddings, coatings, and inhibitors. It also advocates the use of risk-based inspection (RBI) and non-destructive evaluation (NDE) methods to proactively monitor degradation. As a critical reference, API RP 939-C supports refinery engineers and corrosion specialists in optimizing maintenance strategies and minimizing the risk of failures in hydro processing systems [45].

The study compiles experimental data, field observations, and predictive models, offering a valuable reference for corrosion engineers, particularly in downstream units like hydrotreaters handling diverse feedstocks [46].

The paper also discusses mitigation strategies, including material selection, use of corrosion inhibitors, and system design. Overall, it highlights the importance of an integrated understanding of environmental and process parameters to effectively manage and control CO_2 corrosion in oil and gas infrastructure.

The study focuses on environments with sulfur-rich feedstocks, where corrosion risks are elevated due to the formation of corrosive species like hydrogen sulfide. The authors demonstrate how ER probes provide continuous, in-situ measurements of metal loss, offering a reliable and non-intrusive method for assessing corrosion rates under actual operating conditions [47].

The results support the effectiveness of ER technology in identifying corrosion trends and aiding in proactive maintenance planning, thereby enhancing the safety and efficiency of refinery operations. This case study presents a detailed failure analysis of a corroded heat exchanger tube in a naphtha hydro treating (NHT) unit. The investigation focused on the root causes of premature tube degradation, emphasizing metal loss due to acidic condensation. Through visual inspection, metallographic examination, and chemical analysis of deposits, the study identified severe localized thinning and pitting on the inner tube surface. The results revealed that the corrosion was primarily driven by the condensation of acidic species, such as hydrogen sulfide (H_2S) and ammonia (NH_3), forming ammonium bisulfide (NH_4HS) and acidic water in cooler zones of the exchanger. These compounds led to accelerated corrosion, particularly under low-flow and low-pH conditions. The authors conclude with recommendations for improved operational practices, including temperature control, neutralizer optimization, and enhanced drainage to prevent future failures [48].

Conclusion

This study provides a comprehensive data-based analysis of corrosion conditions in Naphtha Hydro treating (NHT) units, with a focus on identifying critical factors influencing corrosion mechanisms, understanding material degradation trends, and proposing mitigation strategies. The findings highlight the multifaceted nature of corrosion in NHT systems, which is influenced by a combination of operational parameters, feedstock composition, process temperature and pressure, and the presence of corrosive species such as sulfur compounds, naphthenic acids, chlorides, and hydrogen sulfide.

Data collected from operating units and laboratory simulations indicate that high temperatures particularly above 220$^{\circ C}$ significantly accelerate naphthenic acid corrosion, especially in areas with high flow velocity such as the hot effluent transfer lines and reactor outlets. Additionally, the presence of sulfur species, although sometimes protective at lower concentrations, can contribute to localized corrosion and the formation of iron sulfide scales that eventually detach, exposing fresh metal surfaces. Corrosion rates were observed to be higher in startup and shutdown phases due to fluctuations in pH and temperature, emphasizing the importance of stable operational control.

Materials performance analysis showed that traditional carbon steel components are particularly vulnerable in the NHT environment unless adequately protected or replaced with corrosion-resistant alloys such as stainless steels (e.g., 316L, 347H) or low-alloy steels with proper lining and cladding. The study also underscores the critical role of proper process monitoring, inhibitor injection (e.g., for neutralizing acids or controlling sulfide-induced corrosion), and feedstock pretreatment to reduce contaminants. Moreover, statistical regression and correlation analyses revealed that feed sulfur content, TAN (Total Acid Number), temperature gradients, and water content are significant predictors of corrosion rate variability. These insights pave the way for developing predictive maintenance models and risk-based inspection (RBI) programs that can enhance the reliability and safety of NHT units. In conclusion, mitigating corrosion in NHT units requires an integrated approach that combines real-time data monitoring, process optimization, appropriate material selection, and predictive analytics. The implementation of these strategies will not only reduce maintenance costs and unplanned shutdowns but also improve the overall operational efficiency and lifespan of the unit. Future research should focus on developing advanced corrosion sensors, machine learning-based prediction models, and novel corrosion-resistant coatings tailored for the hydro treating environment.

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