Integrating Emerging Corrosion Monitoring and Mitigation Technologies for Onshore and Offshore Oilfield Assets

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Abstract

Corrosion remains a life-cycle integrity threat to onshore and offshore oilfield assets because water wetting, acid gases, oxygen ingress, deposits, microorganisms and hydrodynamic forces interact across changing operating conditions. This critical review integrates established corrosion chemistry and control with recent developments in networked sensing, distributed fibre-optic monitoring, robotics, interpretable machine learning, digital twins, self-healing coatings and advanced repair. The synthesis distinguishes evidence generated by laboratory screening, field monitoring, inspection and engineering assessment. Recent literature shows that connected sensing and data-driven models can improve spatial coverage and risk prioritisation, but field transfer remains constrained by sparse defect labels, uncertain sensor location, changing multiphase flow, limited external validation and the tendency to infer localised damage from average corrosion rates. The review proposes a threat-led framework that begins with corrosion circuits and credible mechanisms, qualifies controls under representative chemistry and flow, validates new technologies against independent wall-thickness or defect measurements, and links uncertainty to auditable intervention decisions. Onshore and offshore assets share electrochemical mechanisms but differ substantially in access, communications, environmental loading and repair logistics. The principal conclusion is that emerging technology creates value only when it strengthens the evidence chain from exposure and damage mechanism to verified defect, fitness-for-service assessment and intervention. Priority research should focus on time-separated field validation, uncertainty-aware sensor fusion, transferability between assets and prospective comparison with existing integrity programmes.

Keywords: *corrosion management; oilfield integrity; pipeline monitoring; digital twin; machine learning; smart coatings; offshore assets*

1. Introduction

1.1 Background

Corrosion in oilfield environments is initiated when a susceptible material comes into contact with an electrolyte under conditions that sustain anodic dissolution alongside a compensating cathodic reaction. In production systems, the electrolyte is most commonly produced or injected water rather than the hydrocarbon phase. Parameters such as water cut, flow regime, pressure, temperature, brine salinity, and acid-gas partial pressures fluctuate throughout a field's operational life, meaning that the same steel grade may encounter markedly different exposure conditions at a wellhead, separator, flowline, or low-lying pipeline segment. Intermittent wetting and localized water accumulation can generate conditions that bulk fluid sampling fails to capture (Kermani & Morshed, 2003; Nešić, 2007, 2012; Laycock et al., 2024). The primary internal threats include aqueous CO_2 corrosion, sour-service damage in H_2S-containing systems, oxygen-assisted attack following ingress, under-deposit corrosion, and microbiologically influenced corrosion. These mechanisms are not mutually exclusive. An iron carbonate film may reduce CO_2 corrosion under favorable chemical conditions; however, film disruption, sand impingement, or a shift in pH can expose fresh steel to attack. Service environments containing H_2S introduce additional hydrogen-related cracking risks, even when average metal loss appears limited. Microbial activity is governed by biofilm development and local chemistry; the mere presence of microorganisms in produced water is insufficient to establish them as the causative agent of localized pitting (Enning & Garrelfs, 2014; Knisz et al., 2023; Little et al., 2020).

Corrosion damage also varies significantly by location. Downhole tubing, completion components, wellheads, and flowlines may each be exposed to distinct fluid compositions, temperatures, and inhibitor delivery constraints. In wet-gas pipelines, water condensation on the upper pipe wall creates a threat zone that chemicals injected into the bottom-of-line liquid may not reach. External corrosion in soil, marine, and atmospheric environments requires coating systems, drainage strategies, and cathodic protection measures tailored to the specific setting. Consequently, material selection, design decisions, and chemical treatment programs must be guided by the credible damage mechanism rather than a single generalized corrosion rate (International Organization for Standardization [ISO], 2010, 2020; Laycock et al., 2024; Farh et al., 2023; Solovyeva et al., 2023). The consequences of corrosion include leakage, repair and shutdown expenditures, environmental releases, and personnel injury. The NACE International IMPACT study estimated a global annual cost of corrosion across all industry sectors of approximately $2.5 trillion, equivalent to 3.4% of global GDP during the study period; this figure does not represent an estimate of losses specific to the oil and gas industry (NACE International, 2016). Within oil and gas assets, time-averaged coupon measurements may obscure severe localized pitting, while thickness surveys characterize damage only at the inspected locations. In-line inspection provides broader coverage for qualifying pipelines but is contingent on tool capability, physical access, and the accurate interpretation of reported anomalies (Parlak & Yavasoglu, 2023; Papavinasam, 2014).

These limitations underscore the need for an integrated integrity management program. ISO 21457 governs materials selection and corrosion control for production equipment from the wellhead onward and explicitly excludes downhole components, while ISO 15156 addresses the qualification of metallic materials exposed to H_2S in environments where cracking is a concern. ASTM G31-21(2025) identifies the variables that affect immersion mass-loss testing, and ASTM G170-26 provides guidance for the laboratory evaluation of oilfield and refinery corrosion inhibitors. Recent comprehensive reviews emphasize the importance of combining

environmental characterization, material qualification, inhibitor delivery, monitoring, and inspection into a unified program, while acknowledging that a formulation demonstrating strong performance under laboratory conditions must be further qualified against the actual service envelope (ASTM International, 2025, 2026; Farh et al., 2023; Mouneir & El-Shamy, 2026).
The objective of this review is to evaluate the chemistry, established control

1.2 Review Questions and Contribution

The review addresses three questions: Which emerging technologies materially improve the evidence available for oilfield corrosion management? What prevents laboratory or prototype performance from transferring to onshore and offshore service? Which validation and governance practices are required before an analytical output can influence inspection, repair or operating decisions? The contribution is a mechanism-led synthesis that joins corrosion chemistry, sensing, analytics, mitigation and integrity assessment, with an explicit field-qualification pathway and a comparative onshore-offshore implementation framework.

2. Review Approach and Scope

This article presents a narrative critical review of published research and technical standards on corrosion monitoring and mitigation in onshore and offshore oilfield assets. The literature discussed includes foundational mechanistic studies, recent technology studies and reviews, and standards relevant to material selection, inhibitor evaluation and pipeline integrity. The scope covers corrosion chemistry, established controls, monitoring and inspection, predictive analytics, digital twins, emerging protective materials and repair technologies. The article synthesizes existing knowledge; it reports no new laboratory experiments, field measurements or model-training results. The literature is organized thematically and assessed according to the evidence it provides: laboratory demonstration, monitored field performance, measured defect characteristics and engineering acceptance. Comparisons consider the exposure environment, measurement method, relevance to oilfield service and requirements for independent validation. For digital models, the discussion examines data quality, test-data independence, uncertainty and the connection between predictions and inspection or maintenance decisions. Differences in materials, fluid chemistry, flow and exposure duration preclude treating reported performance values as directly equivalent; the synthesis is qualitative and does not pool effect sizes.

3. Critical Synthesis and Discussion

This section compares findings reported in the literature and develops their implications for corrosion management. The proposed workflows, validation programmes and onshore–offshore applications are recommendations derived from the synthesis, rather than results generated by the authors.

3.1 Corrosion chemistry and damage mechanisms

3.1.1 Electrochemical foundations

In a conducting aqueous film, iron oxidation occurs at anodic sites

$$Fe \rightarrow Fe^{2+} + 2e^{-} \quad (1)$$

Cathodic reactions consume the electrons. In acid media, hydrogen evolution may be written as

$$2H^{+} + 2e^{-} \rightarrow H_2 \quad (2)$$

Where dissolved oxygen is available, oxygen reduction can occur, expressed in near-neutral alkaline notation as:

$$O_2 + 2H_2O + 4e^- \rightarrow 4OH^- \quad (3)$$

These half-reactions describe charge balance but do not by themselves predict the rate; transport, surface chemistry and scale formation also matter (Kermani & Morshed, 2003; Nešić, 2007).

Corrosion requires access to an electrolyte. Hydrocarbon-rich flow does not eliminate risk if water intermittently wets a low point or water droplets impinge on a surface. The local concentration of aggressive species may differ markedly from a bulk fluid sample. Deposits restrict transport and create a distinct microenvironment. An integrity assessment therefore combines chemistry, flow regime, wall condition and damage morphology rather than relying on one bulk concentration (Nešić, 2012; Laycock et al., 2024). Figure 1 summarizes the electrochemical cell described above.

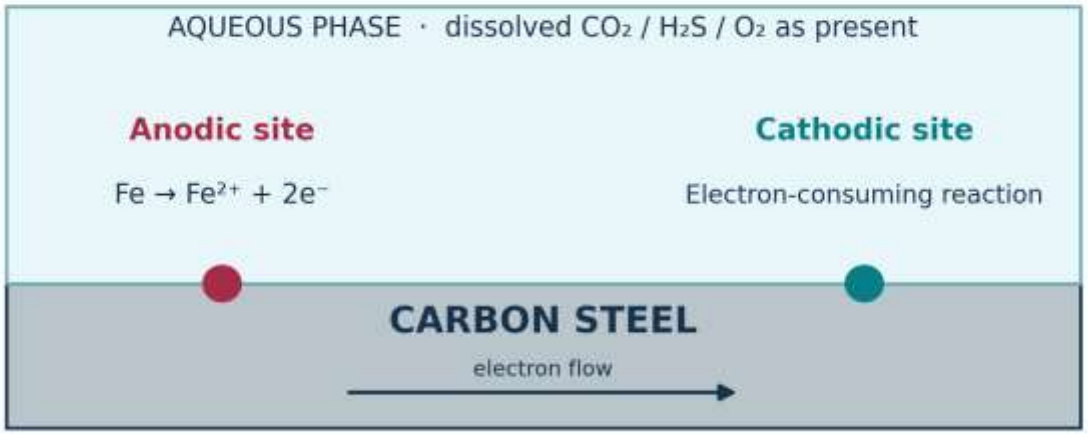


Figure 1. Simplified electrochemical cell on water-wet carbon steel.
Original schematic based on Kermani and Morshed (2003) and Nešić (2007).

3.1.2 Carbon dioxide corrosion

CO_2 dissolves into the water phase and participates in carbonate equilibria. Dissolved CO_2 forms carbonic acid, which can dissociate into hydrogen and bicarbonate ions. These hydrogen-bearing species can support cathodic reduction while steel dissolves anodically. Corrosion severity depends on CO_2 partial pressure, pH, temperature, brine composition, flow and the evolving surface film (Kermani & Morshed, 2003; Nešić, 2007). When Fe^{2+} and carbonate activities generate sufficient supersaturation, $FeCO_3$ may precipitate. A compact adherent scale can limit transport and reduce corrosion; a porous or disrupted scale gives less protection. Consequently, temperature does not imply a simple monotonic rate trend: higher temperature may accelerate reaction and transport while also favoring protective precipitation. Laboratory rankings that ignore scale history can misrepresent field performance (Kermani & Morshed, 2003).

Top-of-line corrosion is a related but distinct risk in wet gas service. Water condenses on the cooler upper wall and can create a thin corrosive phase that receives less benefit from a chemical injected into the liquid at the bottom of the line. Prediction requires thermal, condensation and chemistry information, not only an average aqueous corrosion model (Laycock et al., 2024). The competing pathways for film protection and continued attack are summarized in Figure 2.

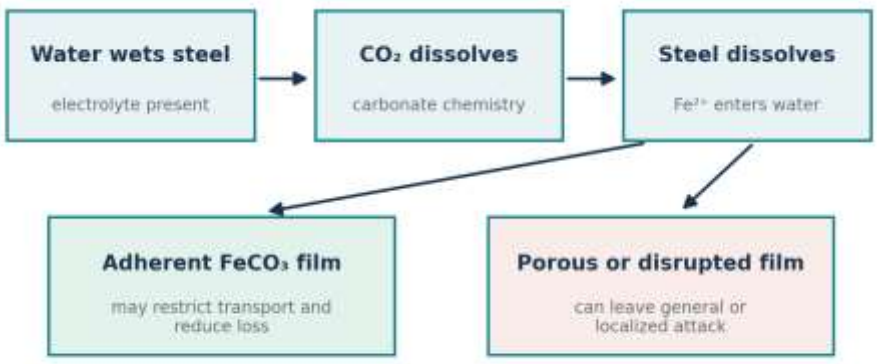


Figure 2. Conceptual pathways for iron carbonate film protection or continued CO_2 attack. *Original schematic based on Kermani and Morshed (2003); outcomes depend on local conditions.*

3.1.3 Hydrogen sulfide and sour service

H_2S dissolves in produced water and reacts with steel to form iron sulfides. Depending on conditions, the deposit can influence general corrosion, localized attack and hydrogen entry. Sour environments also raise risks of sulfide stress cracking and other hydrogen-related damage, which cannot be judged from a mass-loss coupon alone. ISO 15156 defines requirements and recommendations for selecting and qualifying metallic materials for H_2S-containing oil and gas production systems (ISO, 2020).

A corrosion inhibitor cannot substitute for material qualification under sour-service criteria. The evaluation must consider H_2S partial pressure, pH, chloride, temperature, strength, hardness and the exact material condition as relevant to the applicable part of ISO 15156. Chemical treatment may control metal loss but cannot be assumed to remove cracking susceptibility (ISO, 2020; Papavinasam, 2014).

3.1.4 Oxygen, chloride, deposits and erosion corrosion

Oxygen is normally limited in many closed production systems, yet it can enter during maintenance, water injection or chemical preparation. Even small ingress can shift cathodic reaction kinetics and change the character of attack. Chloride raises conductivity and can destabilize passive surfaces, especially for materials whose resistance relies on a passive film. Scale, sand and corrosion products can create differential environments beneath deposits. High-velocity solids and droplets may mechanically remove protective films and amplify corrosion at bends or restrictions. The phrase “erosion corrosion” should be reserved for combined mechanical removal and electrochemical loss rather than applied to all flow-related corrosion (Papavinasam, 2014; Solovyeva et al., 2023).

3.1.5 Microbiologically influenced corrosion

Microbiologically influenced corrosion (MIC) arises when microbial activity changes the chemistry or electrochemical conditions at a surface. Sulfate-reducing microorganisms can produce sulfide; some organisms may directly or indirectly influence electron transfer and create spatially heterogeneous biofilms. A positive microbial count alone does not prove MIC as the cause of a pit. A stronger diagnosis combines deposit and surface evidence, chemical context,

microbial analyses and corrosion morphology (Enning & Garrelfs, 2014; Knisz et al., 2023; Little et al., 2020). Control can involve water management, cleaning, biocide treatment and monitoring of biofilms or deposits, subject to compatibility and environmental constraints. Repeated biocide dosing without understanding the wetting pattern and deposit burden can leave protected niches untreated. MIC should be assessed alongside CO_2 and H_2S processes because mechanisms may coexist (Enning & Garrelfs, 2014; Little et al., 2020). Table 1 summarizes the principal damage mechanisms and their control implications.

Table 1. Principal damage mechanisms and discriminating evidence

Mechanism	Conditions and evidence	Main control implication
CO_2 corrosion	Water wetting; dissolved CO_2; pH and $FeCO_3$ scale observations	Control water contact; qualify inhibitor and scale behavior
H_2S/sour cracking	H_2S exposure; iron sulfides; material hardness and cracking evidence	Select material to ISO 15156; test for relevant cracking mode
Oxygen-related attack	Dissolved oxygen ingress; injection or maintenance history	Exclude oxygen; monitor ingress and treatment
MIC	Biofilm/deposit evidence plus relevant microbial and chemical analyses	Clean, sample deposits and qualify biocide strategy
Erosion corrosion	High-impact flow/solids at bends or restrictions; film removal	Modify geometry/solids control; test under representative flow

3.2 Mitigation and assessment



Figure 3. Mechanism-based corrosion management cycle for oil field assets.
Original synthesis from ISO (2010), Papavinasam (2014) and NACE International (2016).

3.2.1 Materials and design

The first design decision is whether a material can tolerate the service environment throughout the asset life. Carbon steel remains attractive where corrosion allowance and a reliable treatment programme can manage exposure. Corrosion-resistant alloys, cladding or nonmetallic liners may be appropriate for more aggressive or inaccessible environments, but selection must consider

fabrication, joining, galvanic interfaces, pressure, temperature and life-cycle cost. ISO 21457 provides a mechanism-based selection framework for equipment from the wellhead onward; it does not cover downhole components (ISO, 2010; Papavinasam, 2014). Figure 3 relates the environment and credible threats to controls and verification.

Design measures include avoiding liquid traps and dead legs, enabling drainage and pigging, locating injection points where the chemical enters the water phase, and providing access for coupons, probes and inspection. In wells, completion design and artificial-lift configuration affect chemical delivery; batch treatments can leave periods with reduced protection. Design for inspectability is especially valuable where localized corrosion is the governing risk (Solovyeva et al., 2023).

3.2.2 Chemical inhibition and treatment

Oilfield film-forming inhibitors often contain polar functional groups that adsorb at the steel/water interface while an organic portion helps form a water-displacing layer. The chemistry is formulation-specific; imidazoline derivatives, amines and other organic mixtures may differ in adsorption, partitioning and persistence. Performance depends on dose in the water phase, mixing, temperature, brine, competing chemicals and exposure time. A good static result does not establish delivery to every field surface (Papavinasam, 2014; Solovyeva et al., 2023).

For comparable blank and treated tests, inhibitor efficiency is

$$IE\ (\%)\ = \frac{CR_0 - CR_i}{CR_0} \times 100 \qquad (4)$$

where CR_0 and CR_i are corrosion rates measured with the same method and exposure conditions. When coupon mass loss Δm is recorded in mg, density ρ in g cm^{-3}, exposed area A in cm^2 and exposure time t in h, the mean penetration rate in mm year^{-1} is $87.6\Delta m/(\rho At)$. State the cleaning method and the actual area exposed. A percentage reduction in mean rate does not quantify maximum pit depth, cracking susceptibility or performance during dosing interruptions (ASTM International, 2025, 2026).

Other chemical controls include oxygen scavengers where oxygen exclusion cannot be assured, biocides for demonstrated microbial threats and pH management where feasible. These chemicals can interact with scale inhibitors, demulsifiers or formation fluids. Selection should therefore include compatibility testing, emulsion behavior, foaming, deposit tendency and an assessment of environmental discharge constraints. ASTM G170-26 describes laboratory approaches for evaluating oilfield and refinery corrosion inhibitors; laboratory ranking still needs field confirmation (ASTM International, 2026; Papavinasam, 2014).

3.2.3 External protection

External corrosion requires a different barrier. Coatings isolate steel from soil, seawater or atmosphere, and cathodic protection reduces the tendency of exposed areas to dissolve electrochemically. Coating defects, shielding, poor electrical continuity or inadequate current distribution can leave sections unprotected. These methods address external exposure and do not replace treatment of an internal produced-water phase. The design should integrate coating inspection, cathodic protection surveys and periodic reassessment (Papavinasam, 2014).

3.2.4 Testing, monitoring and inspection

A defensible laboratory programme characterizes the metal and fluid, establishes an uninhibited control, tests multiple doses and exposure times, and reports replicate variability. Immersion

coupons estimate cumulative average loss; electrochemical methods can reveal shorter-term response but require careful interpretation as films and conductivity change. Rotating-cylinder, rotating-cage and jet-impingement devices can screen selected hydrodynamic effects, whereas a flow loop may better reproduce a multiphase flow regime at greater cost. ASTM G31-21(2025) guides immersion testing but does not specifically evaluate localized attack, environmentally assisted cracking or solution-flow effects. ASTM G170-26 guides oilfield inhibitor qualification under relevant service factors. Specify which field features each test reproduces and which it cannot (ASTM International, 2025, 2026).

Field monitoring combines corrosion coupons, electrical resistance or linear-polarization probes where appropriate, produced-water chemistry, inhibitor residual or tracer measurements, operating history and inspection. Ultrasonic thickness measurement and in-line inspection can reveal wall loss patterns; neither a single coupon nor a single probe establishes full-circuit integrity. Inspection intervals should reflect credible mechanisms and consequences. Disagreement between indicators is a reason to investigate sampling location, inhibitor delivery and localized damage rather than average away the discrepancy (Papavinasam, 2014; Parlak & Yavasoglu, 2023; Nešić, 2007). Table 2 compares the evidence and limitations of these methods.

Table 2. Evidence generated by common assessment methods

Method	What it measures	Key limitation
Mass-loss coupon	Time-averaged metal loss at the coupon location	May miss a remote pit and smooth short excursions
Electrochemical probe	Local response over shorter intervals	Requires interpretation of film, conductivity and process changes
Fluid and deposit analyses	Aggressive species, treatment residual and deposits	Bulk fluid can differ from a trapped local water phase
Ultrasonic / in-line inspection	Wall thickness and spatial loss pattern	Resolution, access and coverage vary by asset
Metallography / microbiology	Morphology and evidence of possible MIC	Attribution requires multiple lines of evidence

3.3 Advances and Challenges in Established Mitigation

3.3.1 Emerging prospects

The most useful prospect is more reliable integration of mechanisms and operational data. Mechanistic models can combine water chemistry, temperature, flow and scale behavior to identify likely corrosion windows, but their predictive power depends on accurate wetting and local composition. Laycock et al. (2024) emphasize the challenges of modelling wet-gas pipelines, especially where condensation, fluid distribution and inhibition interact. Models should be calibrated against representative field measurements and report uncertainty rather than a single apparent precision.

New formulations are being studied to reduce environmental burden, improve persistence and handle mixed CO_2/H_2S exposure. A “green” label does not establish field safety or performance. Biodegradability, aquatic toxicity, production-chemical compatibility and efficacy at the required dose need evidence under service conditions. Monitoring data may support earlier intervention, provided sensors are maintained and the data are tied to a verified damage mechanism (Solovyeva et al., 2023; Mouneir & El-Shamy, 2026).

3.3.2 Operational challenges

Water cut and wetting are dynamic. A field can move from oil-dominated flow to persistent water wetting, while operating shutdowns can change temperature and condensation. Formation-water mixing can alter scale propensity, chloride and pH. Sand production may remove an otherwise protective film. These changes create both model uncertainty and inhibitor-delivery risk (Nešić, 2007, 2012).

Evidence quality is another limitation. Corrosion rates measured under different conditions should not be compared as if they were a controlled experiment. Reporting often omits the exposed metal composition, brine analysis, gas partial pressure, dissolved oxygen, flow regime, exposure duration or replicate dispersion. A result reported only as inhibitor efficiency obscures the untreated rate and any pitting. Continuous field protection also depends on chemical stock, metering-pump uptime, injection location and monitoring response (Papavinasam, 2014; Solovyeva et al., 2023).

Mixed damage mechanisms complicate attribution. Deposits may host microorganisms, trap water and conceal oxygen ingress. Sour-service cracking requires a separate assessment from corrosion-rate control. External and internal corrosion may coexist across a pipeline system. The appropriate response is a mechanism-based threat register that maps each plausible threat to the evidence required and the action it triggers (ISO, 2010, 2020; Little et al., 2020).

3.3.3 Inhibitor Testing Gaps and Future Validation

The immediate research gap is the transfer of inhibitor rankings from convenient static tests to multiphase and intermittently wetted assets. A feasible research programme would first define a service envelope using representative fluid assays and operating records. A staged design would screen formulations against an uninhibited control, then vary temperature, CO_2 partial pressure, salinity and hydrodynamic conditions for the strongest candidates. Water fraction and oil–water partitioning should be included where multiphase service is relevant. This staged design avoids an impractically large fully crossed experiment. H_2S exposure belongs only in appropriately equipped specialist facilities. A separate stop-and-restart test should examine loss and recovery of protection during interrupted injection (ASTM International, 2026).

Primary endpoints should include average mass-loss rate, maximum pit depth and pit-density description, surface morphology, and time-resolved electrochemical response where the method is valid. Report replicates, randomize order where feasible and quantify uncertainty. A statistical model may examine interactions among the selected factors, but the number of runs and assumptions must be justified before significance testing. Shortlisted formulations should undergo compatibility testing and a controlled field trial with defined baseline, inhibitor-delivery checks, inspection locations and pre-agreed action thresholds. A low coupon rate at one point is not proof of protection throughout a circuit. Figure 4 summarizes the proposed screening and field-validation sequence. Table 3 links the main testing gaps to proposed evidence and decision criteria.

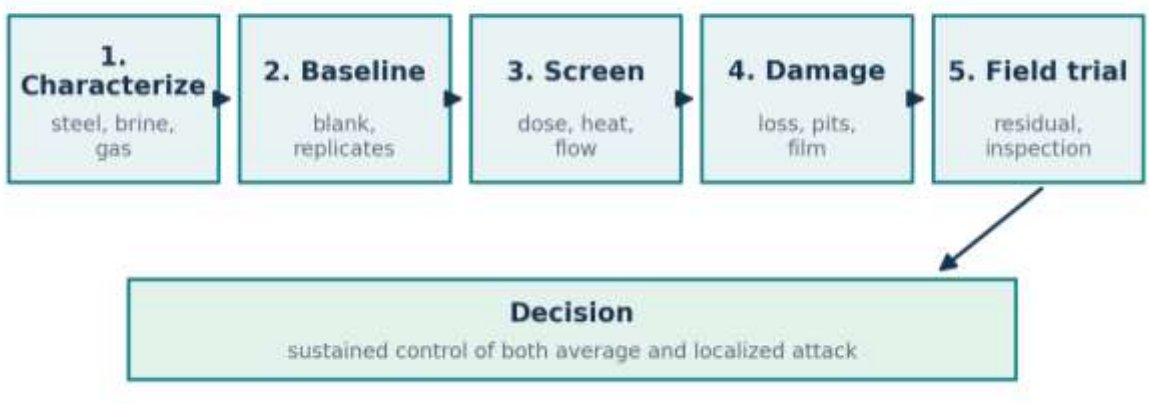


Figure 4. Proposed sequence for inhibitor screening and field validation.
Original synthesis informed by ASTM International (2025, 2026) and Nešić (2007).

Table 3. Research gaps and proposed evidence

Gap	Proposed test	Decision criterion
Static-to-flow transfer	Paired immersion and representative-flow screening	Rate and pitting remain controlled under both exposures
Intermittent dosing	Stop/restart exposure with time-resolved monitoring	Protection recovers without excessive transient attack
Mixed chemistry	Brine and gas matrix with chemical compatibility tests	No adverse precipitation, emulsion or loss of inhibition
MIC attribution	Surface, deposit, chemistry and microbial analysis	Convergent evidence before biocide selection
Field validation	Monitored trial with baseline and operating log	Sustained trend improvement and no new localized damage

3.4 Emerging Monitoring and Inspection Technologies

3.4.1 Networked sensors

Wireless ultrasonic thickness sensors can track fixed locations without repeated rope access. Electrical-resistance probes measure cumulative metal loss, while linear-polarization-resistance methods estimate electrochemical rates in suitable conductive aqueous media. Permanently installed acoustic-emission or guided-wave systems can flag changes over extended pipe lengths, but geometry, temperature, deposits, and operating noise affect interpretation. Distributed optical-fiber sensing offers spatial coverage; each implementation must be evaluated for the physical quantity it measures (Chen et al., 2025). Ultrasonic testing (UT) and in-line inspection (ILI) provide reference measurements for validating monitoring trends (Parlak & Yavasoglu, 2023). Permanent thickness monitoring is most effective when its location follows a credible corrosion mechanism. For a wet-gas line this might be a condensation or water-hold-up site; for a separator it may be a nozzle, interface, or lower shell region. Sensors need traceable calibration, temperature compensation, corrosion allowance context, and a maintenance plan. A network transmitting frequent measurements does not improve decisions if probes are poorly located or if sensor drift is interpreted as wall loss.

Fiber-optic methods offer distributed spatial measurements but differ in their physical measurand. Distributed acoustic sensing detects vibration and acoustic changes; distributed temperature sensing resolves thermal patterns; distributed strain sensing measures deformation. Chen et al. (2025) link strain response to nonuniform steel-pipe corrosion in a coastal exposure experiment. Applying such a method to a buried or subsea production pipe requires independent confirmation of bonding, pressure and thermal cross-sensitivity, defect sizing, and long-term sensor survival.

3.4.2 Advanced inspection and robotics

High-resolution magnetic-flux-leakage and ultrasonic in-line inspection map metal-loss features where lines are piggable. Phased-array ultrasonics and full-matrix-capture data with suitable reconstruction can characterize selected welds and complex geometries. These tools measure different defect attributes and have different detection and sizing limits; inspections should therefore specify the target threat, required resolution, coverage, and verification method.

Guided-wave ultrasonics can screen from one accessible ring over a substantial length, but indications generally require localized confirmation. Phased-array UT and total focusing techniques improve local characterization of geometry and wall loss. An in-line inspection result additionally depends on tool specification, coverage, positioning, and repeatability; matching defects between runs is necessary before calculating a growth rate. A baseline feature measured differently in two campaigns can create a false acceleration. For unpiggable lines, tethered tools, external guided waves, selective excavations, and permanently mounted sensors may be combined after confirming feasibility.

Robotic inspection changes access rather than the underlying physics of defect detection. A camera-equipped drone can document atmospheric coating damage, while a UT drone requires suitable coupling and stable contact. Offshore remotely operated vehicle (ROV) surveys can map external coating defects and anode consumption; an autonomous underwater vehicle (AUV) can efficiently cover a subsea route, but accurate relocation of small defects, biofouling removal, subsea communications, and measurement of internal corrosion remain difficult. Robotics should produce geo-registered observations and a list of required follow-up measurements.

3.4.3 Microbiological and chemical surveillance

Molecular methods such as quantitative polymerase chain reaction (qPCR) and sequencing can reveal microbial communities that conventional culture misses. Lv et al. (2024) emphasize the coupled role of microbial communities, biofilms, and environmental conditions in MIC. A positive biological signal does not prove microbiologically influenced corrosion: interpretation also requires deposits, chemistry, biofilm context, and localized metal-loss evidence. Online water chemistry and inhibitor-residual measurements can identify changes in corrosivity and treatment delivery; calibration and sample representativeness are essential.

Microbiological surveillance is stronger when it records sample location, collection method, treatment timing, and whether the material is planktonic water, deposit, or attached biofilm. Molecular assays detect organisms or genes but do not directly measure metal loss. The deep-sea review by Ge et al. (2025) reinforces the environmental specificity of microbial interactions. Trend changes should trigger hypothesis-driven sampling and inspection rather than automatic attribution of every pit to MIC.

3.5 Predictive Analytics and Digital Twins

Recent studies broaden the digital evidence base. Hu (2024) used interpretable ensemble learning to predict internal corrosion rate and analyse factor influence, showing the value of combining performance with explanation. Wang et al. (2024) demonstrated a pipeline-condition digital-twin architecture that links sensor data, models, probabilistic inference and the physical asset. Jones et al. (2025) reviewed artificial intelligence for offshore pipeline asset integrity and emphasized data reliability, integration and regional constraints. Okyere (2025) used computational fluid dynamics to evaluate internal-corrosion risk in a wet sour-gas pipeline setting. Together, these studies support hybrid data-and-physics workflows, but they do not remove the need for independent thickness or defect verification on the target asset.

Machine-learning models can rank inspection locations or forecast wall loss from asset history, chemistry, flow, treatment, and measured defects. Physics-guided models encode electrochemical and transport constraints, reducing reliance on correlations alone. A useful twin joins an asset register, operating history, corrosion threat model, georeferenced inspection, and uncertainty estimates. Wang et al. (2024) demonstrate a pipeline condition-monitoring architecture linking a physical asset, digital representation, knowledge base, and probabilistic inference; its results are a case study rather than proof of general field accuracy. Its outputs should include condition, forecast interval, and an actionable threshold. Models trained on one field can fail when water chemistry or operating mode changes, so prospective validation on later inspection campaigns is preferable to random splitting of repeated measurements from the same asset. A practical validation plan compares forecasts against independently measured remaining wall thickness and defect growth. Report mean absolute error and uncertainty coverage for rates, precision and recall for alarms, and calibration of risk estimates. Monitor missing data and drift. A human integrity engineer should review proposed derating, shutdown, or repair decisions. DNV-RP-F101 provides a recognized assessment route for pipelines with corrosion defects under specified loading; a predictive score does not replace such engineering assessment (DNV, 2025). Analytical outputs should remain advisory unless they have passed the operator's management-of-change, cybersecurity, functional-safety and engineering-approval processes; they must not override protective systems or code-based assessments.

A predictive pipeline should begin with a corrosion-circuit data model: unique asset ID, location, metallurgy, nominal and measured wall thickness, pressure, temperature, phase behavior, water cut, gas composition, chemistry, inhibitor dose and residual, inspection date, tool uncertainty, and intervention history. Time alignment matters because a laboratory sample collected after a shutdown may not describe conditions when a pit grew. Data should distinguish genuine zeros from missing measurements and retain the original observation and its provenance.

Useful modelling tiers include an interpretable rules-based baseline, a mechanistic corrosion estimate, and a statistical model trained on repeated field data. Gradient-boosted trees or random forests can rank factors and estimate risk, but correlated location identifiers may become shortcuts rather than causal predictors. A physics-guided model can constrain plausible ranges and couple flow, chemistry, and electrochemistry. For rare failures, accuracy is misleading: the model should report false-negative burden, precision of high-priority alarms, calibration, and uncertainty. A chronological and asset-disjoint test set probes whether the model generalizes beyond a repeated inspection record.

Peng et al. (2025) extend the digital-twin concept to virtual–real evaluation of deep-sea corrosion. Transfer to an oilfield asset requires independent validation under its operating conditions. A field twin should preserve the chain from measured defect through uncertainty,

engineering assessment, recommended action, review and subsequent verification.
In a future onshore pilot, an outcome could be a correctly prioritized excavation where independent UT or ILI verifies a predicted wall-loss hotspot. For an offshore pilot, it could be an inspection interval or vessel campaign adjusted after a sensor trend and validated by subsea measurements. Compare both against the existing program on defect detection, false alarms, intervention cost, outage time, and missed severe features. DNV-RP-F116 frames submarine pipeline integrity as a maintained management system, making documentation and re-assessment integral to deployment (DNV, 2021).

3.6 Emerging Mitigation and Repair Technologies

The most recent coating literature increasingly combines nanocontainers, inhibitor release and autonomous response. Cao et al. (2025) reported a self-healing anticorrosive coating based on an MCM-41 nanocontainer and triazinyl inhibitor. This is credible proof of concept, but qualification for oilfield use still requires pressure-temperature cycling, immersion in representative production fluids, adhesion after damage, repair procedures and compatibility with cathodic protection.

3.6.1 Materials and protective surfaces

Research directions include self-healing polymer coatings, nanocomposite barrier coatings, engineered surface textures, and improved corrosion-resistant alloys. Laboratory salt-spray or immersion performance cannot be assumed to predict long-term service under pressure cycling, impact, ultraviolet exposure, marine fouling, or coating holidays. Qualification should measure adhesion, permeability, compatibility, and repairability under representative conditions. For subsea use, coating choice must also account for cathodic protection and possible shielding.
Self-healing coatings should be treated as laboratory proofs of concept until cyclic damage, representative production-fluid exposure and field testing demonstrate durability. Qualification should also establish adhesion after damage, repairability and compatibility with cathodic protection (Cao et al., 2025; Farh et al., 2023).
For buried and submerged steel assets, external corrosion control commonly combines coatings with cathodic protection (CP), with inspection of coating defects, anode status, electrical continuity, and interference. Subsea anodes cannot be assumed effective merely because they were installed; potential measurements and consumption surveys are needed in their relevant design context. Connected CP monitoring is particularly useful across dispersed onshore networks, but reference-electrode placement, electrical noise, telemetry outages, and secure access affect interpretation.

3.6.2 Chemical and biological control

More targeted inhibitor programs link dosing to water cut, flow, residual concentration, and corrosion measurements. Encapsulated or controlled-release inhibitors are promising where continuous delivery is difficult, but residence time, release kinetics, downstream compatibility, and environmental discharge limits must be demonstrated. Biocide programs should combine treatment evidence with deposit control and corrosion response; microbial counts alone are insufficient proof of performance.
Chemical programs require measurement of delivery as well as outcome. A metering pump setpoint is not proof that inhibitor reaches a water-wetted low point. Sampling must account for phase partitioning and residence time. A practical feedback loop tracks chemical concentration

or residual, coupon or probe trends, water chemistry, solids, and inspection. In sour or high-temperature service, candidate formulations require compatibility and qualification; claims that a new inhibitor is environmentally preferable need a documented toxicity and discharge assessment.

3.6.3 Repair and additive manufacturing

Composite wraps, engineered clamps, spool replacement, and localized repair can restore function when an approved design supports the loading and environment. Additive manufacturing may accelerate production of replacement parts and inspection-tool components, but pressure-containing components require material qualification, nondestructive examination, traceability, and applicable code acceptance. Repair selection must follow defect sizing and fitness-for-service assessment; it cannot be based solely on an algorithmic anomaly.

After a defect is verified, options include pressure reduction, monitoring under a justified interval, engineered clamps, qualified composite repairs, replacement, or shutdown. Repair feasibility offshore is strongly influenced by water depth, vessel access, metocean windows, and subsea connection design. A novel additive-manufactured part or composite system must satisfy its applicable qualification and acceptance path; it should not be presented as interchangeable with a code-qualified replacement. Defect assessment should follow an applicable engineering procedure rather than an unverified prediction (DNV, 2025).

3.7 Onshore and Offshore Deployment

Table 4. Operational comparison of onshore and offshore corrosion management.

Decision factor	Onshore	Offshore
External exposure	Soil, groundwater, atmospheric wetting	Seawater, splash zone, marine growth
Inspection access	Excavation, roads, drones, inline tools	ROV or vessel, diver limits, subsea access
Key controls	Coating, cathodic protection, drainage	Marine coating, anodes or impressed current, materials
Monitoring priority	Buried-line CP and water traps	Subsea anodes, risers, difficult-to-access topsides
Data constraint	Distributed assets and connectivity	Underwater communication and positioning
Intervention cost	Land access and disruption	Vessel mobilization and weather window

For an onshore mature-field gathering network, a sensible pilot combines risk-ranked locations, fixed thickness sensing at water traps, CP records, chemistry, and a targeted in-line inspection campaign. For an offshore platform and subsea tieback, it combines permanently installed sensors at accessible high-risk circuits, ROV visual/anode surveys, subsea inspection where technically feasible, and a registered history of measured defects. The final technology mix follows asset-specific threat assessment. Table 4 summarizes the operational differences between onshore and offshore deployment.

a. Illustrative onshore application: consider an aging buried gathering line with intermittent flow and rising water cut. Segment the line by fluid and geometry; identify low points and CP

anomalies; compile chemistry and treatment history; run a baseline inspection where possible; deploy fixed thickness sensors only at justified hotspots. If a model ranks an area highly, confirm it by targeted inspection or excavation before modifying pressure or repair plans. Changes in land access, flooding, third-party damage, and intermittent connectivity must be included in operational planning.

b. Illustrative offshore application: a subsea tieback connects a well cluster to a platform.

Assess internal wet-gas or produced-water corrosion separately from external coating and anode performance. Establish piggability and ILI specifications at design stage; combine platform-accessible monitoring with route and CP surveys by ROV or AUV. If a local anomaly emerges, register the exact location and use a qualified follow-up technique to size it. The cost of a vessel campaign may justify denser monitoring, but deployment choices must account for subsea power, pressure containment, retrievability, and sensor replacement.

For both settings, operational readiness is more than sensor installation. A data owner must verify units, timestamps, calibration, alarm acknowledgement, and transfer to the integrity register. Cybersecurity matters for remote monitoring because a manipulated reading could misdirect inspection priority. Human review and an auditable intervention record preserve accountability when predictive analytics is introduced. Figure 5 compares the conceptual evidence pathways for onshore and offshore assets.

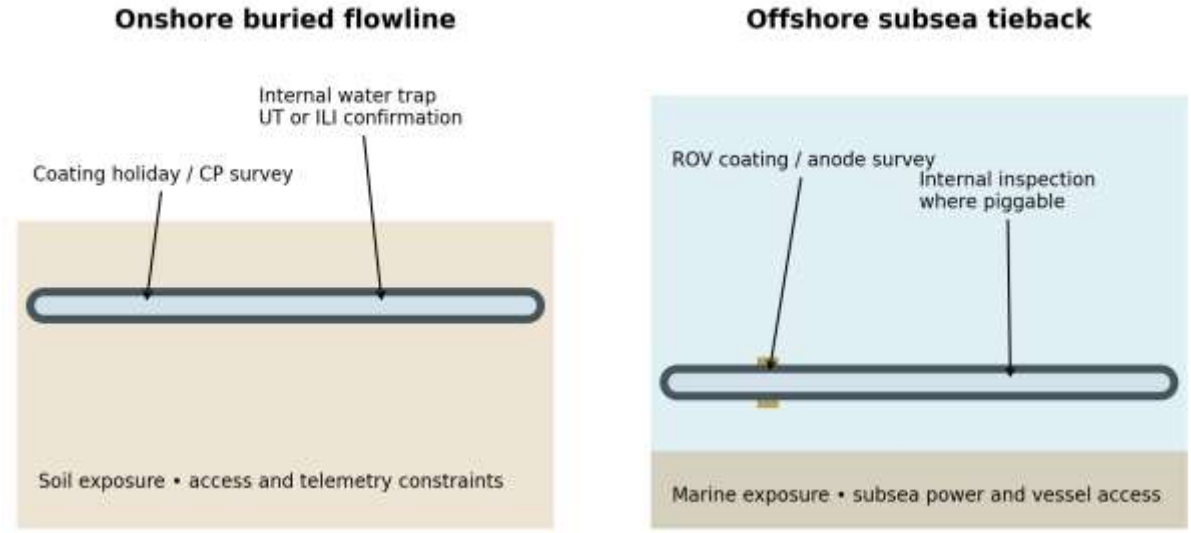


Figure 5. Conceptual onshore and offshore corrosion evidence pathways. The marked points indicate candidate inspection locations; the drawing is not to scale.

3.8 Implementation Framework and Research Gaps

The following framework is proposed from the literature synthesis and has not been tested as part of this review.

i. Step 1: divide the asset into corrosion circuits and document environment, material, fluid regime, and credible damage mechanisms.

ii. Step 2: establish baseline thickness, defect maps, coating and cathodic-protection condition, and data quality.

iii. Step 3: pilot one or two new technologies against a trusted reference measurement.

iv. Step 4: define alarm thresholds, repeatability, uncertainty, false-alarm response, and

ownership of decisions.

v. Step 5: link measurements to integrity assessment and interventions, then evaluate performance after a full inspection cycle.

The major research gaps are reliable prediction of localized corrosion under changing multiphase flow; transfer of models between fields; validated integration of microbiology with metal-loss data; durable subsea sensors; representative qualification of smart coatings; and methods to report uncertainty in low-frequency inspection datasets. A rigorous future study should compare a physics-guided model with a conventional statistical baseline across both onshore and offshore circuits, using time-separated validation and independent thickness measurements.

3.8.1 Research gap synthesis

Table 5. Evidence-based research gaps and testable directions. Findings are summarized within each source's actual setting.

Study	Method / setting	Main contribution	Limit for oilfields	Research opportunity
Lv et al. (2024)	Review of pipeline MIC mechanisms and protection	Integrates biofilms, microbes and environment	Review; no single transferable prediction rule	Link biofilm, chemistry and measured local pit growth
Wang et al. (2024)	Pipeline digital twin case study with probabilistic inference	Demonstrates connected condition architecture	Generalization to production fluids and offshore service untested	Validate twin on time-separated oilfield inspection data
Chen et al. (2025)	Distributed optical-fiber sensing on coastal steel pipes	Shows spatial detection of nonuniform corrosion response	Wharf exposure differs from pressurized multiphase flow	Quantify strain-to-wall-loss error under field transients
Cao et al. (2025)	Laboratory inhibitor-loaded self-healing epoxy	Demonstrates responsive coating concept	Long-term oilfield service and repairability unproven	Test cyclic damage, fluids and coating–CP compatibility
Peng et al. (2025)	Virtual–real evaluation of deep-sea corrosion	Explores coupled prediction and experiments	Site-specific transfer to subsea oil assets uncertain	Externally validate against ROV and UT campaigns
Ge et al. (2025)	Review of deep-sea MIC and biomineralization	Characterizes marine microbial interactions	Ecological evidence does not size oilfield defects	Pair biofilm omics with measured subsea wall loss
DNV (2021; 2025)	Submarine integrity guidance and defect assessment	Defines management and assessment context	Standards do not specify a universal sensor or AI model	Integrate uncertainty-aware analytics into auditable assessment

Table 5 separates demonstrated findings from proposed oilfield applications. The proposed directions require prospective data and independent defect measurements.

A future empirical study could test whether integrating corrosion-rate sensing, chemistry, and inspection histories identifies severe local metal loss earlier than a conventional inspection schedule. Select one onshore and one offshore corrosion circuit with comparable measured outcomes, document differences in sampling and access, and define a baseline risk ranking. Train a model only on past inspections; prospectively test later measurements. Independent UT or ILI defines defect size, while treatment logs and fluid chemistry explain mechanisms. Report detection sensitivity, false alarms, lead time, uncertainty calibration, and intervention cost.

Priority gaps include sensor lifetime under production conditions; direct correlation between distributed strain and residual wall in complex geometries; inference of localized pit growth from sparse measurements; uncertainty-aware use of MIC molecular data; and independent validation of self-healing coatings and digital twins on oilfield assets. Strong research should publish negative as well as positive results and state the operating conditions under which a method fails.

4. Conclusion

Oilfield corrosion is governed by the interaction of an aqueous phase, corrosive species, steel surface condition and the local flow environment. CO_2 corrosion may be moderated by an adherent $FeCO_3$ scale, while H_2S service can introduce cracking risks beyond wall loss. Oxygen ingress, deposits and microbial activity add localized threats. A nominally high inhibitor efficiency under one test condition therefore cannot demonstrate safe service throughout an asset's life (Kermani & Morshed, 2003; Nešić, 2007; ISO, 2020).

The recommended approach is to document the full operating envelope and damage mechanisms, choose materials using the appropriate service standard, design for drainage, treatment access and inspection, screen inhibitors against realistic chemistry and flow with blank controls and replicates, verify field performance with complementary chemical, corrosion and inspection indicators. Progress in modelling, lower-impact formulations and connected monitoring is promising, but its value depends on demonstrable field validity and a responsive integrity management system (ISO, 2010; NACE International, 2016; Laycock et al., 2024).

Emerging corrosion technology adds value when it reveals damage earlier, locates it more precisely, or improves the timing of an intervention. Onshore and offshore assets share electrochemical mechanisms but differ in exposure, access, communications, and repair logistics. The defensible route is a threat-led combination of monitoring, inspection, corrosion control, and engineering assessment. Current evidence supports careful pilots and measured performance; claims of autonomous corrosion management require prospective validation and clear human accountability.

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Conflict of Interest

No conflict of interest was reported.

Data Availability

No new experimental dataset was generated. The article synthesizes the publications and standards listed in the references.

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