

# Field Validation of Nanocomposite Surface Treatment to High-risk Flowlines for Enhanced Corrosion Mitigation and Flow Assurance

Marco Basile<sup>1</sup>, Clara Mattiello<sup>1</sup>, Sara Scarnicci<sup>1</sup>, Davoud Teimouri<sup>1</sup>, Silvia Morrea<sup>1</sup>, Massimo Vergani<sup>1</sup>, Gianluca Baldassarre<sup>1</sup>, Arkan Abdul Sattar<sup>2</sup>, Zaid Ali Hussain Al-Saady<sup>2</sup>, Matthew Sullivan<sup>3</sup>, Alexander Ventura<sup>3</sup>, Sumil Thapa<sup>3</sup>, Matthew Nakatsuka<sup>3</sup>

<sup>1</sup>Eni Global Natural Resources, San Donato Milanese, Milan, Italy

<sup>2</sup>Basra Oil Company, Basra, Iraq

<sup>3</sup>Oceanit Laboratories, Inc., Honolulu, HI, USA

## Abstract

This work details the field application and performance results of the application of a novel omniphobic nanocomposite surface treatment designed to mitigate corrosion damage and enhance energy savings on crude oil and water injection flowlines in one of the oil fields of Basra, Iraq (IOF). A past deployment of this nanocomposite in an Eni upstream facility in Alaska, USA, demonstrated a 36-fold reduction in microbially induced corrosion (MIC), as well as reducing required pumping pressure by up to 30%.

The treatment was deployed at a facility in the Middle East and Northern Africa (MENA) region to both crude oil and water injection flowlines where severe internal corrosion had caused several instances of unplanned maintenance and interventions. A custom transmission pipe setup consisting of two 200 m sections of 0.20 m diameter Schedule 80 API 5L X60 transmission line (one treated, one untreated) was established as part of an existing flow line. Parallel removable spools that could be exposed to identical conditions were a key part of this setup, and test coupons were installed across the entirety of the flowline that could be removed without affecting the operation of the line. Application of the surface treatment was conducted both prior to arrival on site, as well as in-field after welding and joining using a novel hybrid radial spray and pigging field application method.

After a 6-month operational period, test coupons were removed and analyzed for mass loss, treatment durability, and fouling. Preliminary data indicates that coupons treated with the nanocomposite have significantly lower corrosion rates than untreated samples. The treatment was especially effective in areas exhibiting “extremely high” corrosion rates ( $> 0.4$  mm/y), where the treatment **reduced corrosion rates by 177-fold**. All treated samples show excellent structural integrity after use, retaining hydrophobic behavior (water contact angle  $> 90^\circ$ ), and remaining tightly adhered to the test substrate with no evidence of delamination or wear. These findings validate laboratory-scale results of enhanced corrosion resistance and drag reduction and provide quantifiable benchmarks for large scale adoption.

An economic analysis of the nanocomposite deployed across a theoretical 100 km of water and oil service flow lines at the IOF demonstrated the potential to **reduce operations and production downtime by 81%**, enhancing overall flowline reliability and operational performance. From a GHG emissions standpoint, use of the nanocomposite is anticipated to drive a reduction in GHG emissions due to a decrease of energy required to pump oil and water through the flow lines, and a reduction in steel used to replace heavily corroded lines.

## Introduction

Produced water generated in oil and gas production is widely considered to be wastewater and can be extremely corrosive to oil field infrastructure. Preventative steps must be carried out to transport produced water in existing infrastructure. Corrosion in pipelines, especially from produced water transportation, is an industry wide problem and

constant monitoring, and remediation is vital to ensure that pipeline damage is minimized, and operational capacity is maintained across various oil production infrastructure. Traditional mitigation strategies to minimize corrosion damage from water injection have been focused on the use of corrosion inhibitors (CIs), chemicals pumped into the pipeline at regular intervals that can neutralize or passivate acidic corrosive agents such as hydrogen sulfide (H<sub>2</sub>S) and carbon dioxide (CO<sub>2</sub>), that are present in the flow. While CIs have shown limited success over short periods of time, use of them is a reoccurring capital expense, and the relative dosing requirements must be consistently monitored and optimized as equipment ages and the composition of the extracted hydrocarbons and resulting produced water changes over time. Use of corrosion resistant alloys (CRA) during fabrication and installation of produced water pipelines is extremely cost prohibitive, making it an unrealistic solution.

A secondary challenge stemming from high corrosion rates in produced water lines is the rapid formation of scale and deposits that build up on the inner wall of the pipeline. This scale can result in increased surface roughness, leading to increased friction and higher pressure drop, reducing overall throughput. A potential solution to address corrosion and resulting flow assurance challenges in the pipeline is the application of an extremely smooth, corrosion and scale resistant surface flow coat that has inherent low free surface energy. The resulting material would simultaneously act as a water-repelling barrier to lessen corrosion, while the slippery “glass-like” surface finish prevents the accumulation of deposit and reduces frictional drag during operation. In practice, most flow-coats and liners tested for oil-and-gas pipelines have proven to be challenging to handle and implement on a large scale, and factors inherent to the material properties of the coatings themselves have prevented wide adoption across the industry. Examples of such operational limitations include: limited pot life that prevents scaling application past 10 miles, reactivity with acids or hydrocarbon impurities preventing use in certain regions, and required minimum thickness (20 – 35 mil) meaningfully reduces pipeline internal diameter while posing an unacceptably high serious risk factor for downstream damage if the coating material delaminates from the pipeline interior.

### **Statement of Theory and Definitions**

Unlike most existing flow-coat materials, this novel surface treatment nanocomposite technology contains repellent chemical end groups that results in a characteristic low interfacial free energy. This imparts inherent repellency against water and hydrocarbons and has also been demonstrated to inhibit the growth of bacterial biofilms; while proteins can potentially adhere to these “fouling-release” materials, they can be easily removed with minimal shear forces consistent with flow within the pipeline (Krishnan et al., 2008) (Zhao et al., 2005). With direct chemical bonding to steel substrates, the nanocomposite surface treatment can be applied at thicknesses (< 50 μm) up to 95% less than traditional flow-coat materials, making installation substantially faster and less costly, while still providing similar flow assurance and protective benefits (Mansfeld et al., 2024).

In 2020, the nanocomposite surface treatment, trade name DragX™, was tested and evaluated at an Eni-owned and operated plant located in the North Slope borough of Alaska, USA. Results from that deployment demonstrated that surfaces treated with the nanocomposite had a corrosion rate 36-times lower than untreated surfaces. The nanocomposite also was able to completely arrest extremely aggressive microbially induced corrosion (MIC) in a produced water transport pipeline, resulting in virtually no observation of pitting, erosion and fouling over the duration of the study. Calculated operational expenses (OPEX) were reduced by approximately 15% annually, considering the cost of avoided corrective maintenance and downtime (Nakatsuka et al., 2021).

Based on this promising pilot study, a similar methodological evaluation of the surface treatment was conducted on a transmission flowline in the Middle East and North Africa (MENA) region, which faces similar issues despite drastically different operating conditions. The lines of interest have historically experienced severe internal corrosion due to the presence of corrosive gases, brine, and high water cut contained in the extracted hydrocarbon product. This work serves to describe the approach that was used to rapidly respond to the operational needs by applying the nanocomposite technology in a field setting and setting up a methodological approach to evaluate performance such that future full-field deployment can be economically justified.

### **Description and Application of Equipment and Processes**

The deployment effort was bifurcated into two efforts focused on the two facilities located in the IOF. The facilities are specifically dedicated to processing and transport of produced water which has been separated from crude oil, at an annual rate of 60,000 BBL per day. As part of processing, multitudes of differing chemical treatments, including emulsion breakers, corrosion inhibitors, oil defoamers, scale inhibitors, oxygen scavengers, reverse breakers, and biocides are introduced at low 1-20 ppm concentrations. This resulting mixture of treatments may contribute to eventually a highly corrosive liquid, resulting in significant internal and external corrosion within the transport lines. Because of the complexity of the fluid, and the logistical difficulties in either acquiring and exporting field samples, or creating a suitable synthetic substitute for

laboratory testing, it was determined that the most cost-effective method for evaluating performance and compatibility of the surface treatment was to install multiple treated test coupons at various high corrosion rate areas in the operational area (Basile et al., 2025).

Operating in country, on a full active pipeline within an austere environment with minimal supporting infrastructure was seen as a significant hurdle to viability. To address this and demonstrate that it was logistically and economically possible, a pilot deployment was scheduled for approximately 200 m of two newly fabricated 0.2 m nominal diameter pipelines carrying both production well oil (OSL), with up to 20% water cut, and treated water (WSL). The application of the material itself was completed via a customized, tri-axial hydro-pneumatic robotic system. The liquid treatment material was delivered to the tip of a small, remote controlled application lance. The treatment material was atomized and radially sprayed across the interior while the lance itself was centralized and driven through the pipeline interior at a fixed speed. By carefully tailoring key parameters such as the volume of treatment, application pressure, nozzle design, lance travel speed, and spray radius, even coverage across the interior of the pipeline was repeatably achieved on-site without any permanently installed equipment other than what was required for pipe handling. The application tool and the pipeline interior at all stages of application can be seen below in **Figure 1**.



**Figure 1: (a) Radial ID Surface Treatment. (b) Pipeline Interior as Received. (c) Pipeline after Preparation/Cleaning (d) Pipeline after treatment under UV illumination.**

The manifolds, located upstream to the UG transmission lines, were designed to be equipped with bypasses and section valves to grant safe access to removable spool pieces that can be inspected at regular intervals to evaluate performance, such that the main active pipeline sections carrying product did not need to be disturbed. One removable spool was treated with the nano composite, the other was left untreated as a control. At the end of the work, two 3 m spools classified as a water injection line and a crude oil line were placed within the relevant manifolds of the transmission flow lines, located within the selected project site, to be conveniently removed for future inspection in the coming year.

For each selected performance site, a set of in-line coupons were inserted into the active flowline to determine the treatment's survivability and corrosion mitigation properties in the short term and are the focus of this work. Standard strip coupons with dimensions 73 mm x 22 mm x 3.175 mm (2.875 in x 0.875 in x 0.125 in) were fabricated from low-carbon steel 1018 with two mounting holes fabricated into the coupons and plastic washers used to hold the coupon in place. Each coupon was serialized, and normal operation was allowed for a 150-day study period. These coupons were inserted in pairs within each flowline, parallel to flow in the line, with one treated coupon and one untreated coupon to serve as a control. This assembly can be seen in **Figure 2**, with the installation sites for lines OSL and WSL shown in

**Figure 3.**

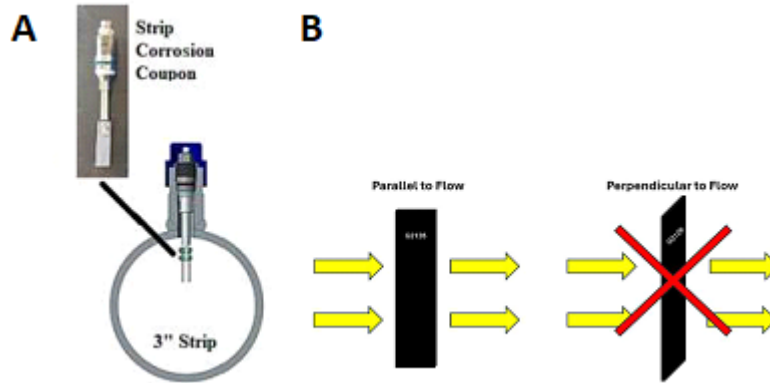


Figure 2: (a) Example of Strip Corrosion Coupon (CC) inserted into active flowline. (b) CC Alignment with Direction of Flow.

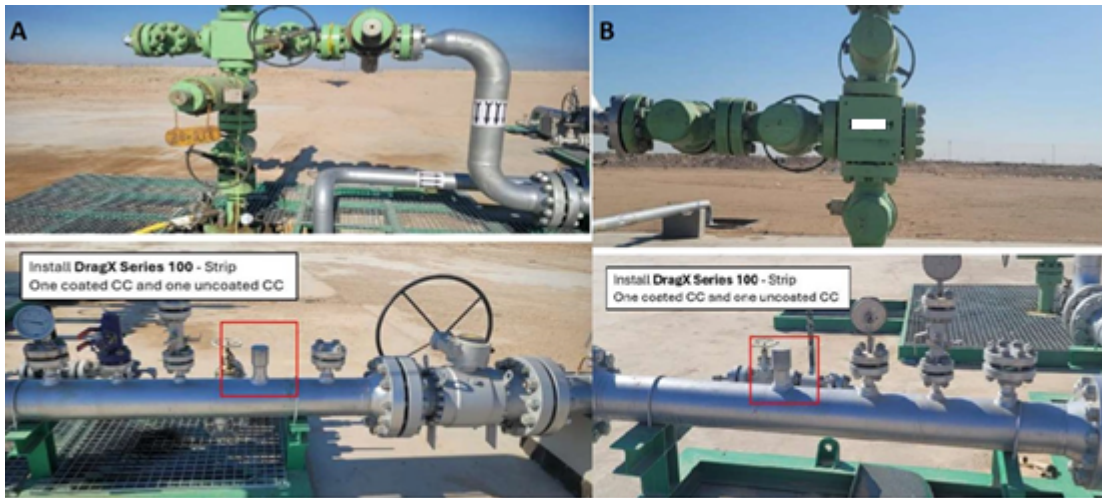


Figure 3: (a) Wellhead OSL (Oil Well) Access Point for Coupon Installation. (b) Wellhead WSL (Water Injection) Access Point for Coupon Installation.

After field extraction, the coupons were evaluated and Corrosion Rate (CR) was calculated according to a slightly modified version of AMPP SP0775-2023, “Preparation, Installation, Analysis and Interpretation of Corrosion Coupons in Hydrocarbon Operations”. Coupons were photographed using a Keyence VR-6000 3D Optical Profilometer, both immediately after receipt in the laboratory (“Pre-cleaning”), and after cleaning with Xylene (“Post-cleaning”). It should be noted that while “Treated” coupons only required approximately 1 minute of soaking in Xylene solution, followed by gentle brushing with a coarse bristle brush, “Untreated” coupons required a minimum of 10 minutes of complete immersion followed by vigorous physical brush removal of loosened scale/corrosion product. CR was calculated in millimeters per year (mm/y) as per Equation (1) below:

$$Corrosion\ Rate\ (CR) = \frac{W \times 1000 \times 365}{A \times T \times D} \quad (Eq. 1)$$

Where:

W = mass loss post-cleaning (g)

A = exposed surface area (mm<sup>2</sup>). With washers/mounting holes excluded, estimated at 3354.83 mm<sup>2</sup> (5.2 in<sup>2</sup>).

T = exposure time, (days) = 150 days

D = density of coupon metal, (g/cm<sup>3</sup>). For carbon steel, 7.86 g/cm<sup>3</sup>.

Under the established AMPP SP0775-2023 guidelines, average general corrosion rates < 0.05 mm/y are categorized as “Low”, rates between 0.05 – 0.2 are classified as “Moderate”, rates > 0.2 mm/y are categorized as “High”, and rates > 0.4 mm/y are categorized as “Extremely High” (2x or higher than “High” values). It should be noted that these calculations assume a uniform loss of metal, and do not include analysis for pitting rate, as corrosion rates were expected to be “high” to “extremely high”, necessitating removal of scale through glass bead blasting. Such a cleaning procedure would likely affect or interact with the applied surface treatment, either blunting the effect of removal, making it impossible to accurately

calculate the maximum pit depth, or would result in the complete removal of the treatment from the surface, resulting in excessively large mass loss that would not be indicative of field performance.

To ensure that the treatment survived the environmental conditions and remained functional, even after cleaning and removal of any adhered scale or corrosion product, images under UV illumination were taken (using a standard LED visible blue flashlight, wavelength 395nm). Water contact angle of the coupon surfaces was also measured via a contact angle goniometer (ramé-hart) to ensure the treatment maintained its omniphobic properties.

### Presentation of Data and Results

A list of coupons and their locations can be seen below in **Table 1**. Overall weight loss for treated coupons as a percentage of pre-test weight was significantly reduced across all the five monitoring stations versus untreated controls. Visual inspection of the treated coupons shows that despite the reduced cleaning of the surface, treated coupons were still substantially cleaner than untreated control coupons. UV fluorescence imaging shows that in all cases, the treatment also remained tightly adhered to the coupon substrate and unbroken after the 150-day inline exposure. Evidence of adhered scale and other deposits prior to any cleaning was also substantially reduced on the treated samples, as can be seen in **Figure 4 - Figure 8**. Notably, both untreated and treated samples taken from the new oil well OSL showed slight mass gain and little sign of overall corrosion. This may be expected, as this line alone was the only non-produced water line in the five areas that were sampled.

A second site that showed minimal corrosion where samples were taken from the Oil Train Outlet, the furthest point upstream at the refinery, where the fluid flowing across the test coupons had the highest relative corrosion and scale inhibitor concentrations (injected at the well area immediately before joining into the referenced produced water line). Of the remaining three sections, all exhibit either “high” (Intermediate Tank Inlet, New Water Line), or “extremely high” (Water Injection Inlet) corrosion rates.

**Table 1: In-Line Coupon Data**

Coupon Serial Number / Treatment Condition	Coupon Location	Pre-test weight (g)	Post-test weight (g)	Post-cleaning weight (g)	%wt loss
G2015 / UNTREATED	Oil Train Outlet	37.0285	37.2273	37.1589	+0.352
G2123 / TREATED	Oil Train Outlet	37.4280	37.5135	37.4530	+0.067
G2010 / UNTREATED	Intermediate Tank Inlet	37.0419	35.4473	34.8475	-5.924
G2122 / TREATED	Intermediate Tank Inlet	37.4110	37.4774	37.4282	+0.046
G2032 / UNTREATED	Water Injection Inlet	37.1242	28.0100	27.5656	-25.748
G2126 / TREATED	Water Injection Inlet	38.2280	38.5380	38.2874	+0.155
G1724 / UNTREATED	New Oil Well (OSL)	36.9949	36.6529	37.0644	+0.188
G2121 / TREATED	New Oil Well (OSL)	37.4430	37.5469	37.4616	+0.050
G1725 / UNTREATED	New Water Line (WSL)	37.0201	40.6108	34.4148	-7.038
G2120 / TREATED	New Water Line (WSL)	37.3320	39.7137	37.3417	+0.026

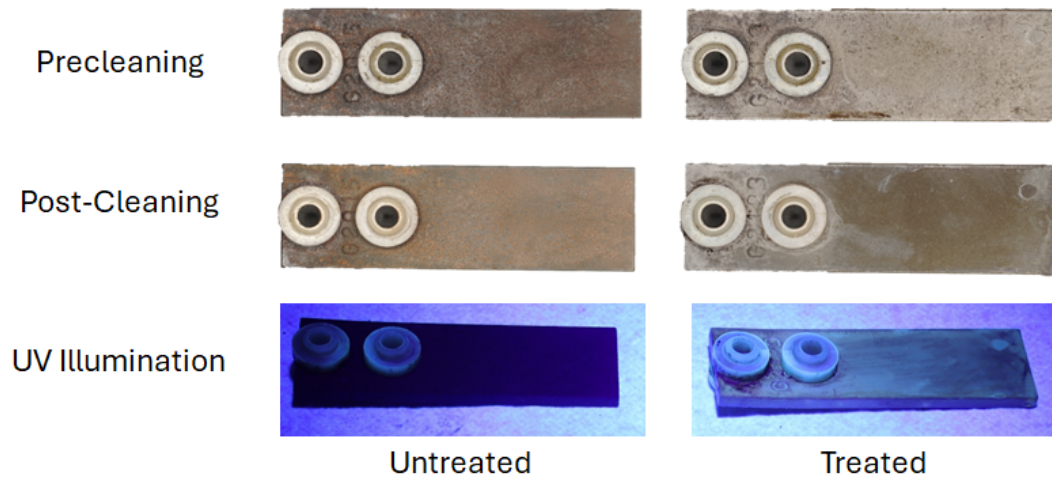


Figure 4: Oil Train Outlet Coupons Before Cleaning, After Cleaning, and under UV Illumination

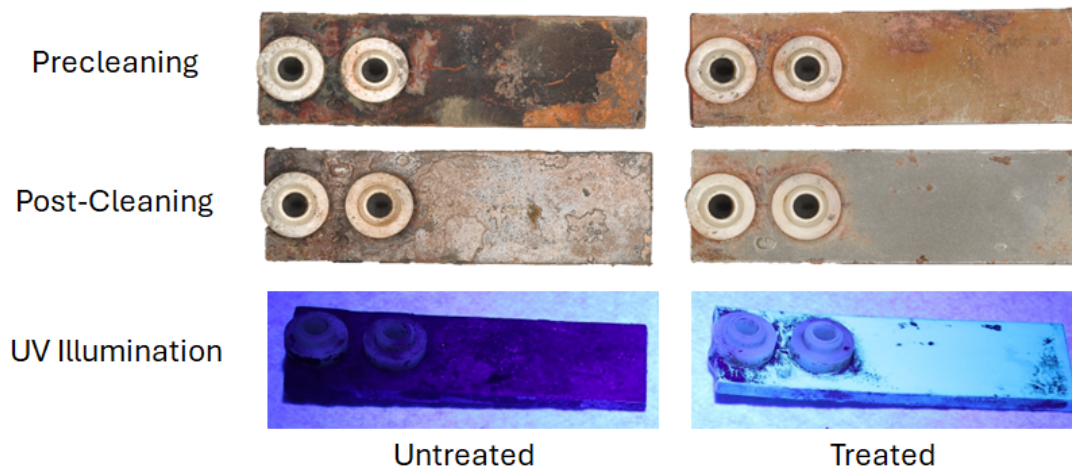


Figure 5: Intermediate Tank Inlet Coupons Before Cleaning, After Cleaning, and under UV Illumination

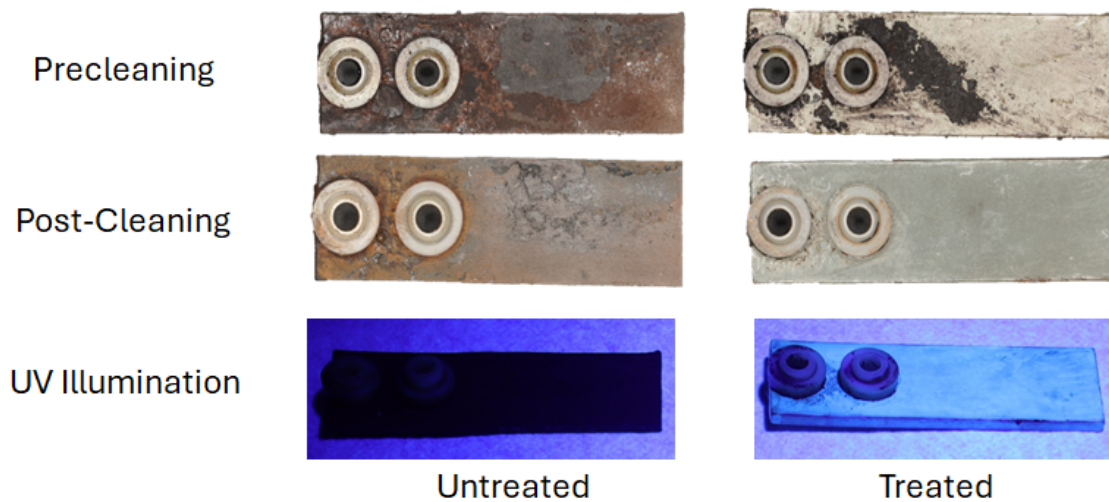


Figure 6: Water Injection Inlet Coupons Before Cleaning, After Cleaning, and under UV Illumination

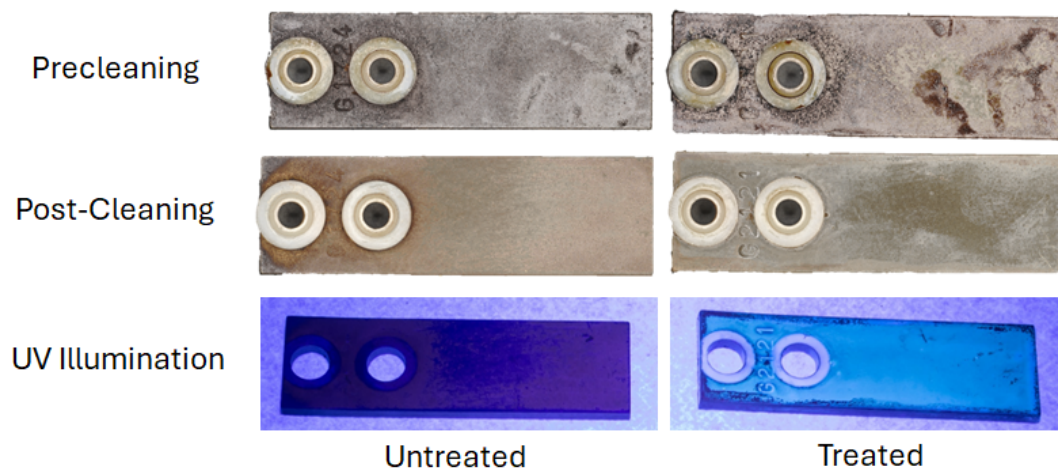


Figure 7: New Oil Line OSL Coupons Before Cleaning, After Cleaning, and under UV Illumination

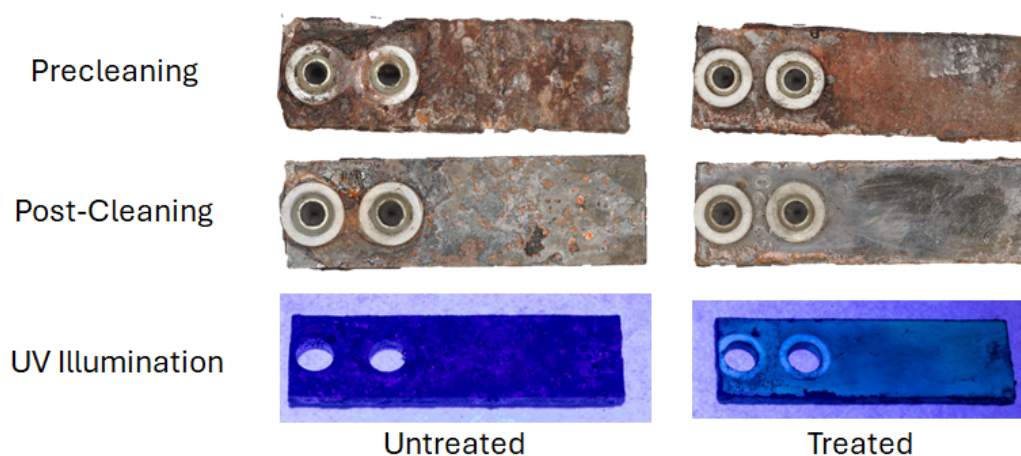


Figure 8: New Water Line WSL Coupons Before Cleaning, After Cleaning, and under UV Illumination

Corrosion rate was calculated for coupons extracted from each test site and converted to mm/y. This calculation, along with the total amount of scale removed from the surface during cleaning, and the post-cleaning contact angle of water on the coupon surface can be seen in **Table 2** below. Corrosion rate can be used to estimate wall thickness loss per year under flowline conditions. Values less than 0.05 mm/y can be mostly disregarded; positive values (showing weight gain during the study) will generally be evidence of scale deposition, adherence after cleaning, or slight swelling of the treatment material over time. As a sample calculation, WSL is a 0.20 m (8 in) nominal diameter line with a 12.7mm (0.5 in) wall thickness, and corrosion allowance of 3 mm. Based on the current estimation of a 0.24 mm wall loss per year, an expected lifetime of 12.5 years could be expected in this system with no maintenance intervention. However, with the incorporation of the treatment, this lifetime could be substantially lengthened with the near elimination of field maintenance, based on the complete arrest of corrosion. For the line with the most severe corrosion (Water Injection Inlet), a 0.457m (18 in), Schedule 80 pipeline would have an estimated wall thickness of roughly 23.9mm (0.94 in). Even assuming a doubled corrosion allowance of 6 mm, at a CR of -0.881 mm/yr, this line would exceed the allowance in just over 81 months (6.8 years), necessitating complete removal and reinstallation.

Interestingly, the treatment appears to have a substantial impact in also reducing scale adherence to the surface in all the high corrosion rate conditions, while having a negligible effect compared with the non-treated surfaces in environments with low to no corrosion. This makes intuitive sense as the surface treatment can repel dissolved particulates within the pipeline flow, making it more difficult for initial scale layers to form, thus resulting in an amplifying effect in reducing the adhesive force of any scale deposition. A similar effect was previously observed when evaluating the effect of the same surface treatment in preventing hydrate formation, asphaltene deposit, and wax adhesion in a complex, multi-phase flow (Pickarts et al., 2022).

As stated previously, the complex mixture of inhibitors injected into these lines, as well as the multiple sources of water coming from several well sites, make chemical compatibility difficult. Most traditional hydrophobic or corrosion-resistant materials may face difficulty in maintaining their performance over extended exposure to such varying chemical concentrations over time. It is thus promising that for all coupon samples, the presence of the nanocomposite treatment (even under lightly adhered scale and oxidation product) could be confirmed through the absence of weight loss, the ability to illuminate the surface of the coupons with UV light, and the retention of omniphobic behavior ( $CA > 90^\circ$ ). It is also noteworthy that for all controls, despite cleaning with xylene and heavy abrasion, sufficient corrosion/oxidation/porosity remained on the surface such that they were either weakly or strongly water wetting, indicating they will likely be susceptible to further rapid corrosion and scale adhesion/formation. Only the OSL / oil-well samples, which were not exposed to any substantial concentration of water, retain a contact angle close to what would be expected for newly fabricated steel (60-70°).

**Table 2: Coupon Data**

Coupon Serial Number / Treatment Condition	Coupon Location	Scale Removed with Cleaning (g)	Corrosion Rate (mm/y)	Water Contact Angle Post Cleaning
G2015 / UNTREATED	Oil Train Outlet	0.0684	0.012	37.4
G2123 / TREATED	Oil Train Outlet	0.0605	0.002	103.9
G2010 / UNTREATED	Intermediate Tank Inlet	0.5998	-0.202	30.9
G2122 / TREATED	Intermediate Tank Inlet	0.0492	+0.002	99.3
G2032 / UNTREATED	Water Injection Inlet	0.4444	-0.881	54.9
G2126 / TREATED	Water Injection Inlet	0.2506	+0.005	104.5
G1724 / UNTREATED	New Oil Well (OSL)	0.0689	+0.006	77.0
G2121 / TREATED	New Oil Well (OSL)	0.0853	+0.002	103.3
G1725 / UNTREATED	New Water Line (WSL)	6.196	-0.240	30.3
G2120 / TREATED	New Water Line (WSL)	2.372	+0.001	103.1

### **Economic Impact of Nanocomposite Treatment to Upstream Operations and Decarbonization**

The oil and gas industry increasingly confronts escalating technical complexities and challenging operational problems such as deeper wells, more aggressive environments, and higher pressures, while balancing the cost pressures to extract hydrocarbons economically. Corrosion often lies at the convergence of these two factors which have amplified the need for economic materials that can provide superior corrosion resistance. For industry, corrosion can result in catastrophic failures, leading to loss of production, safety risks, and significant economic costs. Flowlines with aggressive internal corrosion rates driven by high water cut,  $CO_2/H_2S$ , and solids are widespread in the industry with internal corrosion consistently among the leading causes of pipeline failures. Regulatory and industry data published by the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) indicated that internal corrosion accounts for approximately 60% of corrosion-related pipeline incidents in transmission and gathering pipeline systems (PHMSA, 2018), while AMPP’s comprehensive “IMPACT” study estimated the global cost of corrosion across industries at about USD \$2.5 trillion per year (NACE, 2016).

Historically, these challenges have been difficult to address as many corrosion-mitigation technologies are operationally complex to deploy at scale or require prohibitively high capital costs to implement making them economically unattractive on a project basis. In practice, operators of hydrocarbon production infrastructure have historically faced a binary choice: use conventional cost effective carbon steel flowlines with limited corrosion resistance, shorter effective service life, and higher maintenance and lifecycle costs, or upgrade to solid CRA or duplex materials that can be magnitudes greater in cost

compared with carbon steel, but deliver extended service lives improving overall lifecycle economics when evaluated over 20–30 years (**Table 3**).

**Table 3: Overview of Flowline Cost vs Performance in High Corrosion Environments**

Material	Material Cost (compared with carbon steel)	GHG Emission Factor (compared with carbon steel)	Performance
Carbon steel (CS)	1× (baseline)	2.90 kg CO <sub>2</sub> e/kg (baseline)	Lowest CAPEX; requires corrosion control and monitoring
Solid stainless / duplex CRA	2–4× baseline	2× baseline	Higher alloy content (Cr, Ni, Mo) Duplex and Super Duplex stainless steels (e.g., 22%Cr, 25%Cr) can provide good corrosion resistance, particularly in seawater and chloride-rich environments
Solid high-Ni CRA (e.g., Inconel)	6–40× baseline	3× baseline	Used for very aggressive service especially in sour service applications where high H <sub>2</sub> S levels, elevated temperatures, and acidic conditions; material cost dominates
CRA clad carbon steel	Between CS and solid CRA	1.5× baseline	Can perform similar to solid CRA with reduced cost due to less tonnage; higher installation and QA/QC requirements
Nanocomposite treated carbon steel	1.1-1.5× baseline	1× baseline	Demonstrated good corrosion resistance, superior fouling resistance, and reduced internal drag due to low surface energy properties

Compared with CRA systems, carbon steel pipelines in corrosive environments require persistent operational and lifetime costs to manage corrosion. Preventative maintenance such as continuous or batch chemical injection programs require chemical purchase, transport and storage, operation and maintenance of injection pumps, dosing lines, and monitoring equipment, all of which can represent a material share of annual operating expenses in remote assets. To keep internal corrosion within acceptable limits, operators must also run frequent pigging campaigns, corrosion monitoring, and inspection surveys, adding both direct cost and indirect cost from deferred or interrupted production. Even with good corrosion mitigation programs, residual corrosion risk remains, leaks and failures lead to unplanned outages, repair campaigns, and in severe cases full emergency line replacement with associated lost production, emergency response, and reputational and environmental liabilities. Over a 20- to 30-year field life, these recurring preventative maintenance, corrective maintenance, production downtime, and environmental failure costs can have a significant economic impact on the cost of production, particularly in remote or offshore locations where the cost of intervention is high.

Historical field data from the field operation has been used to validate performance data collected from the treated test coupons after the 6-month evaluation period to project an economic benefit of the nanocomposite at this operating site. Key cost drivers were identified by the operating asset and categorized broadly into chemical injection, corrective maintenance (including flowline replacement), pigging & inspection, environmental impact, production downtime (including lost or deferred production), and reduced energy consumption resulting from a decrease in pumping energy due to reduced internal surface roughness of the treated surfaces (**Table 4**).

**Table 4: Key Drivers Impacting Field Operations and Production**

Category	Conventional Carbon Steel	With Nanocomposite Treatment
Chemicals	High	Low
Corrective Maintenance: Flowline Replacement	High	None
Pigging & Inspections	High	Low
Environmental Impact	High	None
Downtime (PM/CSM)	High	Low
Pressure Drop & Energy Consumption	High	Low

## Economic Benefit: Scale Up Projection

For evaluation purposes, a model assuming 100 km of newly installed 0.20 m (8 in) Schedule 80 API 5L X60 carbon steel pipe water and oil service lines over a 5-year period was used to evaluate the **theoretical lifecycle cost** of using existing carbon steel vs carbon steel treated with the nanocomposite treatment. Projection analyses were based on the quantification of parameters associated with corrective and predictive maintenance, capital expenditures (CAPEX) for nanocomposite and pipeline materials and their installation, as well as other major operational costs (**Table 5**).

**Table 5: 5-Year Evaluation with and without Nanocomposite Treatment**

Category	% Change With Nanocomposite
Preventive Maintenance	<b>Unchanged</b>
Corrective Maintenance	<b>-98%</b>
CAPEX	<b>+26%</b>
Downtime	<b>-81%</b>

If deployed across 100 km of water and oil service flow lines, the nanocomposite has **the potential to reduce future operations and production downtime by 81% with minimal additional investment**, enhancing overall flowline reliability and operational performance. Furthermore, the technology is anticipated to deliver additional indirect benefits attributed to a reduction in preventative maintenance programs, increase integrity and performance of the flowline system over its operational lifetime and reduction of environmental impact.

Finally, from an GHG emissions standpoint, use of the nanocomposite is anticipated to drive a reduction in GHG emissions due to a decrease in pumping energy required to transport oil and water through the flow lines, and a reduction in steel used to replace heavily corroded lines. Theoretically, assuming a GHG emissions intensity of 188 kg CO<sub>2</sub>e to manufacture a 1 m length of 0.20 m (8 in) Schedule 80 API 5L X60 pipe, and projecting a requirement of 100 km of pipe for a full field deployment scenario, it is estimated that the nanocomposite would save 9,350 t CO<sub>2</sub>e in avoided CO<sub>2</sub> emissions, assuming 50% of the line needs to be replaced over a 10-year period.

## Conclusions

This paper serves as a case study demonstrating the corrosion protection and drag-reducing performance of a novel nanocomposite surface treatment in an operational field setting. Over the course of 6 months, the nanocomposite delivered substantial benefits over the untreated controls, completely arresting corrosion and actively resisting scale formation and deposition.

Coupled with the demonstration of applying the material on-site in a remote location utilizing local contractors, this initiative represents a compelling example of how novel technologies can be effectively deployed to address long-standing and complex challenges within the oil and gas industry. Furthermore, the introduction of innovative and disruptive solutions has the potential to stimulate the development of new professional competencies within the local workforce, fostering knowledge transfer and capacity building. In parallel, these technologies enable more sustainable energy operations by reducing the overall carbon footprint, thereby enhancing the environmental performance of production sites and increasing the intrinsic value of the final products derived from such operations.

## References

- Basile, M., Mattiello, C., Morrea, S., Damanti, C., Rocco, S., Fischetti, C., Piccoli, S., Simonetti, A., Bucci, A., Sullivan, M., Ventura, A., Thapa, S., & Nakatsuka, M. A. (2025). Deployment of Nanocomposite Surface Treatment to High-Risk Flowlines. *Paper presented at the OMC Med Energy Conference and Exhibition*, Ravenna, Italy, April 2025.
- Krishnan, S., Weinman, C. J., & Ober, C. K. (2008). Advances in polymers for anti-biofouling surfaces. *Journal of Materials Chemistry*, 18(29), 3405-3413. <https://doi.org/10.1039/B801491D>
- Nakatsuka, M. A., Basile, M., Thapa, S. S., Ventura, A., Pascolini, O., Pellicciotta, L. & Veedu, V. P. (2021). Decarbonization and Improved Energy Efficiency Using a Novel Nanocomposite Surface Treatment. *ADIPEC 2021*, Abu Dhabi, UAE, November 2021. <https://doi.org/10.2118/208080-MS>

- NACE International, (2016) *International Measures of Prevention, Application, and Economics of Corrosion Technology Study*.
- Mansfeld A., Nakatsuka M.A., Mons I., Maldonado M.N., Galvan A., & Elshahawi H. (2024). An All-in-One Internal and External Coating Material for Enhancing Water Conveyance Pipelines. *Paper presented at the Offshore Technology Conference*, Houston, Texas, USA, May 2024. <https://doi.org/10.4043/35279-MS>
- Pickarts, M. A., Brown, E., Delgado-Linares, J. G., Veedu, V., & Koh, C. A. (2022). A Comprehensive Investigation into the Effect of a Low Surface Energy Treatment on Gas Hydrate, Asphaltene, and Wax Formation, Deposition, and Adhesion. *SPE J.* 27: 410–421. <https://doi.org/10.2118/206732-PA>
- PHMSA (September 2018), "Fact Sheet: Internal Corrosion", <https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm>
- Zhao, Q., Liu, Y., Wang, C., Wang, S., & Müller-Steinhagen, H. (2005). Effect of surface free energy on the adhesion of biofouling and crystalline fouling. *Chemical Engineering Science*, 60(17), 4858-4865. <https://doi.org/10.1016/j.ces.2005.04.006>