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Interior Epoxy Coating vs Bare Pipe: Comparative Analysis of Corrosion Mitigation Strategies in Water Pipelines[1]

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***Abstract*— This white paper presents a lifecycle cost analysis of two corrosion mitigation strategies for water pipeline systems: corrosion allowance through increased wall thickness and the application of interior epoxy coatings. The study evaluates the economic and operational performance of both approaches over a 25-year service life, considering capital expenditures (CAPEX), operational expenditures (OPEX).**

I. Introduction

The strategic selection of corrosion mitigation approaches significantly impacts both operational longevity and lifecycle costs in water transmission infrastructure. This investigation evaluates two prevalent methodologies: corrosion allowance designs utilizing increased wall thickness versus epoxy-coated pipeline systems employing protective barriers.

Pipeline systems relying solely on wall thickness augmentation inherently reduce internal diameters, directly increasing pumping energy requirements. This hydraulic inefficiency becomes compounded by the elevated surface roughness characteristics of uncoated steel compared to epoxy-lined alternatives. Furthermore, bare steel systems necessitate continuous chemical inhibitor treatments to mitigate corrosion progression - introducing recurring material costs and operational complexities absent in coated systems.

This study conducts a techno-economic analysis encompassing both capital expenditures (CAPEX) and operational costs (OPEX) across a 25-year service horizon. The evaluation framework incorporates hydraulic modeling, material degradation rates, and chemical treatment protocols to quantify total ownership costs for both mitigation strategies.

II. Background: Pipelines in Chile

High-elevation pipeline systems in Chile, particularly those located at altitudes exceeding 3,000 meters above sea level, present significant cost challenges due to their complex engineering requirements, the need for buried infrastructure, and energy-intensive pumping operations.

The average construction cost for such pipelines is approximately $3.2 million per kilometer, reflecting a 23% increase since 2018. This rise is attributed to factors such as material cost inflation, higher labor expenses, and increased energy prices. These financial pressures underscore the need for innovative financing and operational strategies to support the development of critical water infrastructure in high-altitude regions.

BOOT (Build, Own, Operate, Transfer) contracts are rapidly become a preferred model for securing water resources in the mining sector. These agreements allow mining companies to transfer project risks and reduce upfront capital expenditures by outsourcing the development, ownership, and operation of water infrastructure to specialized firms. This approach enables mining companies to focus on their core activities while ensuring long-term water security and reliable delivery.

Prominent examples of successful BOOT projects include the Centinela and Spence operations, as well as Codelco's SADDN project. These initiatives highlight the practical benefits of this model in addressing water challenges while supporting sustainable development in the mining industry.

These specialized firms are the ones in need to maximize return over their investment and minimize failure risks.

TABLE 1. Significant water pipeline projects.

Name	*Year*	*Owner*	*Size*	*Length*	*Coatings*	*Water*
Monturaqui	1998	MEL	36"	90	FBE	well
Pelambres	2007	AMSA	32	50	FBE	recovered
Coloso	2008	MEL	24"	130	LE➔Bare	desal
Centinela	2011	AMSA	36"	160	Bare	seawater
Candelaria	2012	Lundin	24”	80	FBE&HDPE	desal
Cerro Negro	2013	CAP	24	90	FBE➔HDPE	desal
Mantoverde	2013	Capstone	24"	50	FBE	desal
SGorda	2014	SGSCM	36"	140	Bare➔HDPE	seawater
EWS	2014	MEL	2x42"	160	Primed FBE	desal
Spence SGO	2018	BHP	36"	160	LE	desal
EWSE	2019	MEL	2x42"	160	Primed FBE	desal
INCO	2022	AMSA	24"	60	Bare	desal
QBlanca	2023	Teck	36"	160	Bare	desal
Aconcagua	2025	APacifico	28"	120	LE	desal
PAO	2026	AMSA	28"	60	Primed FBE	desal
C20+	2026	CMDIC	44"	194	FBE	desal
RTomic	2026	Codelco	48"	160	LE	desal
Capellan	2026	Adasa	28"	24	Bare	recovered
TEA	2026	SQM	36"	90	FBE	seawater
Cenizas	2027	MCenizas	12"	120	FBE	desal

LE= Liquid Epoxy; FBE = Fusion Bonded Epoxy.

[1] This is a living document, designed to improve through collaboration. Whether you have detailed technical knowledge, practical experience, or constructive feedback, your input is welcome. We encourage readers to share their insights and suggestions by opening an issue through the GitHub repository.

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III. Case Study Parameters and Computational Methodology

To facilitate a comparative evaluation of different corrosion mitigation strategies, the analysis employs a representative water transport scenario constructed with the following arbitrary parameters:

TABLE 2. ARBITRARY PROJECT PARAMETERS

Parameter	Value	Unit
Pipeline length	100	km
Static head (elevation change)	1000	m
Pipeline outside diameter	28	inches
Design wall thickness assuming no corrosion	9.53	mm
Average corrosion rate	0.15	mm/yr
Density of water	1030	kg/m³
Dynamic viscosity of water	0.0013	Pa·s
Roughness bare year 1	0.068	mm
Roughness bare year 25	0.720	mm
Roughness FBE year 1	0.015	mm
Roughness FBE year 25	0.035	mm
Design flow rate	700	L/s
Service life	25	years
Annual hours of operation	8400	h/yr
Pump efficiency	82	%
Annual discount Rate	10	%
Field internal joint coating service	$1,000	$/joint
Electrical energy	175	$/MWh
Hot-rolled coil (HRC) Chinese spot price	470	$/t
FBE cost per interior surface area	9.0	$/m²

These parameters can be modified in the Excel file included in the GitHub repository.

All computational models and datasets are publicly accessible via GitHub, including an Excel workbook implementing the Newton-Raphson iterative technique for precise determination of Darcy-Weisbach friction factor.

The author expects that this methodological transparency enables independent verification of results while providing an adaptable framework for evaluating corrosion management strategies under diverse operational conditions. This systematic approach aims to advance evidence-based decision-making in pipeline engineering practices.

IV. Capital Expenditure Analysis

A. Steel Pipe Economics

This cost model integrates current hot-rolled coil (HRC) market indices, manufacturing premiums, and logistical expenses to establish a baseline steel pipe pricing. This is because HRC is a primary raw material for steel pipe production, and its price movements closely reflect changes in the broader steel market.

Recent analysis of the Chinese steel market highlights that the production of API 5L X70 steel pipe typically incurs costs ranging between 1.6x to 2.2x the prevailing HRC spot prices. This multiplier reflects the value-added processes required to transform raw HRC into finished X70 pipe [1, 2, 3].

For this study, the following assumptions will be applied:

1. *Baseline hot-rolled coil (HRC) Chinese spot price*

The model assumes a Chinese HRC spot price of **$470 per tonne**, based on current market conditions [4].

2. *Value-added multiplier:*

A conservative value-added multiplier of **1.6x** is used to estimate the manufacturing premiums cost from China Hot rolled coil Spot Price to API 5L X70 steel pipe cost.

3. *Transportation cost*

This study uses **$170/t** transportation cost from the steel mill in China to the job site in Chile. This cost includes inland trasnportation from the mill to the Chinese port ($15/t), ocean freight ($120/t), and inland transportation between Chilean port and the job site ($35/t).

Using these parameters, the estimated cost for API 5L X70 steel pipe is calculated as follows:

X70 Cost per Weight (*CPW*) = **$470/t** × **1.6** + **$170/t** = **$922/t**

The average corrosion rate for the corrosion allowance (bare pipe) strategy it is assumed at **0.15 mm/yr** which should holds validity for industrial water systems with adequate inhibitors injection [5]. Note that the extra wall thickness considered for the corrosion allowance strategy assumes corrosion inhibitors to mitiagate the corrosion from a standard 0.22-0.32 mm/yr to the current assumed 0.15 mm/yr [6].

The wall thickness required for the coated pipe is **9.53 mm** (project design wall thickness). Adding 0.15 mm/yr × 25 yr = **3.75 mm** to this wall thickness results in **13.28 mm** of initial wall thickiness for the corrosion allowance strategy. With these values we calculate the total pipeline steel costs via hollow cylinder volumetrics:

$$\mathit{Steel\ Pipe\ Cost} = \frac{\pi}{4} \cdot \left(D^2 - (D - t)^2\right) \cdot L \cdot \rho \cdot \mathrm{CPW} \qquad (1)$$

Where $\boldsymbol{D}$ **= 0.7112 m** (external diameter), $\boldsymbol{t}$ **= 13.28 mm** (bare pipe) or **9.53 mm** (coated system), $\boldsymbol{L}$ **= 100 km** (pipeline length), and $\boldsymbol{\rho}$ **= 7850 kg/m³** (API 5L · X70 steel density).

Replacing these values in (1) we obtain the steel pipe cost for each strategy.

TABLE 3. STEEL COST FOR EACH STRATEGY

Item	*Bare*	*Coated*	*Corrosion Steel*
Wall thickness	13.28 mm	9.53 mm	
Steel Weight	22,857 t	16,491 t	
Steel pipe cost	$21,074,349	$15,204,644	$4,583,412

Extra corrosion steel represents 27.9% of the baseline steel material expenditure.

B. *Interior FBE Coating Economics*

The process of coating the interior of a steel pipe involves two distinct steps. First, an initial coating is applied at the manufacturing facility under controlled factory conditions. Subsequently, once the pipe sections are welded together on-site, a field joint coating is applied to protect the welded joint and ensure continuity of the protective layer.

1. *Shop-applied interior fusion-bonded epoxy (FBE)*

Shop-applied interior fusion-bonded epoxy (FBE) coatings, typically applied at thicknesses up to 500 µm, offer cost efficiencies [7]. These efficiencies stem from industrialized application processes that deliver superior resistance to chloride-induced corrosion and abrasion caused by suspended solids.

Current pricing of $6.50–$6.00/m² for surface treatment processes reflects the integration of material inputs, thermal energy requirements, and automated systems in modern pipe mills, with specific costs varying by region and coating type. This analysis adopts a **$6.00/m²** cost per interior surface area (CPS) to calculate coating expenditures [8].

$$FBE = \pi \cdot D \cdot L \cdot CPS \tag{2}$$

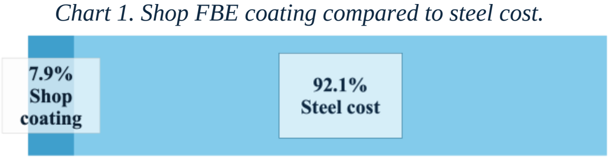
Where ***D* = 0.69214 m** (coated interior diameter) and ***L* = 100 km** (pipeline length).

Replaceing this values in (2):

$FBE = 3.15 \cdot 0.69214 \cdot 100000 \cdot \$6.00 = \$1,304,653$

Implementation costs total $**1,304,653**, representing **7.9%** of the baseline steel material expenditure.

Chart 1. Shop FBE coating compared to steel cost.



2. *Internal Robotic Field Joint Coating*

Steel pipes with shop-applied FBE coatings feature 50 mm uncoated ends (cutbacks) to enable welding, prevent heat damage to coatings during installation, and streamline post-weld field joint recoating procedures. Welding inevitably degrades nearby FBE layers via thermal stress, creating heat-affected zones (HAZ) that require restoration of corrosion protection. To address this issue, robotic crawlers or manual application methods are used to apply field coatings that match or exceed the performance of shop-applied layers.

1998 Project, Minera Escondida Monturaqui, Atacama, Chile 18" – 42" Water Pipeline. 7,500 Field Joint Internally Coated with FBE

The field application process involves cleaning and preparing the cutback area using abrasive blasting to remove contaminants and ensure proper adhesion of the new coating. Specialized epoxy formulations designed for field application are then applied using automated equipment or manual tools. These coatings must cure rapidly under ambient conditions while providing comparable resistance to mechanical damage and chemical exposure as their shop-applied counterparts.

Two dominant robotic coating systems address this:

• *Aegion/CRTS*: Premium systems (20–30% costlier) with low rework rates and precision for large-diameter pipelines.

• *TYHOO Group*: Budget modular robots optimized for sub-28" pipelines.

These robots perform SA2.5 abrasive blasting, apply liquid epoxy via electrostatic nozzles, and use real-time cameras to ensure uniform coverage.

The robotic interior coating service cost per joint varies between $800 to $1,200 per joint depending mainly on the site location, the diameter and the length of the pipeline [9]. This analysis will consider a price per joint of **$1,000 per joint**.

For the 8,334-joint pipeline, this aggregates to **$8,334,000** which is **6.4 times** the cost of the Interior FBE Coating.

TABLE 4. CAPEX COMPOSITION FOR COATED PIPE

CAPEX Item	Cost	%	Surface
Total steel cost	$15,204,644	61.2%	
Field joint coating	**$8,334,000**	33.5%	0.42%
Shop FBE coating	$1,304,653	5.3%	99.58%
Total CAPEX	**$24,843,297**	**100%**	**100%**

As shown in table 5, field-applied inner coating required for this small cutback area is approximately **1,514 times** more expensive per square meter than the shop-applied coating.

3. *Field post-weld interior coating reliability*

It is well documented that field interior joint coating quality is inferior than shop FBE coating. Field conditions—particularly temperature swings (±15°C), humidity variations (30–95% RH), and airborne contaminants (e.g., dust, oils, or salt aerosols)—compromise coating integrity by altering cure kinetics, adhesion properties, and overall durability. These environmental factors significantly impact the performance of field-applied coatings compared to shop-applied systems.

Thermal expansion/contraction cycles induce micro-cracking in partially cured coatings, while moisture ingress disrupts polymer cross-linking, creating pathways for corrosion initiation and propagation. Airborne particulates embed into applied layers, acting as focal points for disbondment, coating failure, or accelerated degradation over time.

This environmental sensitivity explains why field-applied coatings exhibit 2.8× more defects (e.g., delamination, pinholes, uneven thickness, incomplete coverage, or surface irregularities) than shop-applied systems. Improper surface preparation, such as inadequate blast profiles or residual mill scale/oxides, accounts for 61% of failures in third-party audits and inspections.

Photo 1. Displays a clean adhesion test result for a factory-applied FBE coating. The uniform removal of the coating indicates strong adhesion to the substrate, achieved through controlled application processes in a factory setting with optimal surface preparation and curing conditions.

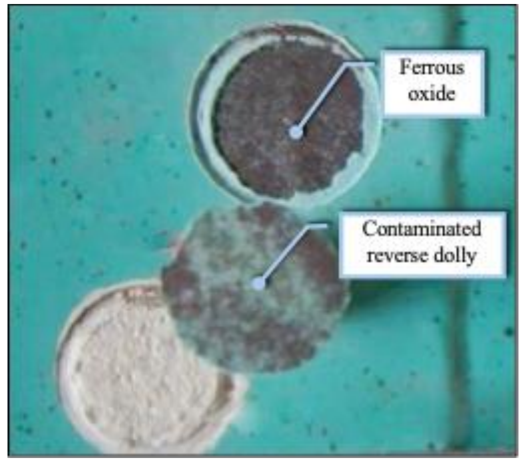


Photo 2. Shows the results of an adhesion test on a field-applied liquid epoxy coating near a weld seam. The presence of ferrous oxide (rust) and contamination on the reverse dolly highlights suboptimal surface preparation and environmental challenges during field application. These defects compromise coating adhesion and increase the risk of corrosion in service.

These flaws reduce coating adhesion strength by up to 40%, weaken barrier properties, and significantly accelerate localized corrosion rates in high-stress weld zones where mechanical strain is concentrated. See photo 2.

As a result, achieving reliable performance from field-applied coatings requires stringent quality control measures, including proper surface preparation, controlled application environments, and adherence to curing specifications. These challenges have driven the market to innovate alternative solutions, such as:

- **FlexSleeve**®. A stiff polymer sleeve with bore seals that is inserted into pipe ends before welding.
- **SIDGMAN**®. A two-piece system—one male and one female—welded in the shop to the ends of each pipe.
- **Style X07**. A very high-pressure Victaulic coupling listed under ASME B31.4. It has been installed in two projects in Chile: 24" MLP INCO and 32" SQM TEA.

Photo 3. SQM's TEA project, a 32" seawater interior FBE coated pipeline was joined by Victaulic's X07 couplings. The need for robot field coating was eliminated.

V. Operational Expenditures

A. Corrosion inhibitors injection

While corrosion allowance provides structural buffer through increased wall thickness, active inhibition via chemical treatments proves more cost-effective for long-distance pipelines.

Experimental validation confirms a **26 ppm** sodium polyphosphate dosage achieves target corrosion rates ≤0.15 mm/year through passivation film formation. Complementary biocide protocols apply weekly 4-hour shock treatments (20 ppm glutaraldehyde equivalent to **0.46 ppm** continuous dose) for microbial control.

OPEX calculation parameters:

- Annual operating hours: 8,400
- Flow rate: 0.7 $m^3/s \rightarrow$ 21,168,000 m^3/year
- Inhibitor cost: $1.8/kg (sodium polyphosphate)
- Biocide cost: $12.8/kg (glutaraldehyde)

Dosage requirements derived from:

- Continuous inhibitor: 26 ppm × 21,168,000 m^3/yr = **550,368 kg/yr**
- Biocide equivalent: 0.46 ppm × 21,168,000 m^3/yr = **9,660 kg/yr**

TABLE 6. OPEX TO ACHIEVE AT LEAST 0.15 MM/YR CORROSION RATE.

Item	***Dosage*** *ppm*	***Price*** *per kg* [10]	***Mass*** *kg per year*	***Cost*** *($/year)*
Inhibitor	26.00	$1.8	550,368	$990,662
Biocide	0.46	$12.8	9,660	$123,648
			Dosing Plant[3]	$12,000
			Total OPEX	**$1,126,310**

[3] Service-Based Infrastructure Model: Third-party managed dosing systems replace owned infrastructure through subscription services ($1,000/month OPEX).

To compare future OPEX cash flows with CAPEX on an equal footing, future cash flows must be discounted to their present value (PV).

The present value is calculated using (3):

$$PV = \sum_{n=1}^{25} \frac{FV_n}{(1+r)^n} \quad (3)$$

Where PV is the Present Value, FV is the future value (annual OPEX of $1,126,310); r is the discount rate, 10%; n is the number of years into the future. Assuming cash flows occur at the end of each period over a 25-year service life, the inhibitors' OPEX present value is calculated as $10,223,565.

B. Inspections

Bare uncoated steel pipes with corrosion allowance and internally epoxy-coated pipes require distinct inspection strategies due to their differing approaches to corrosion management.

For bare steel pipes, inspections focus on monitoring wall thickness loss over time using techniques such as magnetic flux leakage (MFL) or ultrasonic testing (UT). These methods detect material degradation, with repairs involving weld patches, sleeves, or section replacements. Inspection intervals are typically every 3–5 years, with annual costs ranging from $8,000 to $15,000 per kilometer.

In contrast, internally epoxy-coated pipes require inspections to assess coating integrity using techniques like electrochemical impedance spectroscopy (EIS) or linear polarization resistance (LPR).

Repairs involve reapplying liquid epoxy to damaged areas. Coated pipes benefit from longer inspection intervals of 5–10 years and lower annual costs of $4,000 to $8,000 per kilometer.

Table 7 summarizes the key differences in inspection methodologies, frequencies, and costs:

TABLE 8. INSPECTIONS FEATURE COMPARISON.

Concept	*Bare Pipe*	*Coated pipe*
Main Inspection Methodology	Magnetic flux leakage (MFL) and/or ultrasonic testing (UT).	Electrochemical impedance spectroscopy (EIS) and/or linear polarization resistance (LPR).
Repair	Weld patches, sleeves or replace entire section.	Reapply liquid epoxy to the interior surface.
Periodicity	3–5 years.	5–10 years.
Cost/Year	$8,000–$15,000/km	$4,000–$8,000/km

For analytical purposes, this study assumes annual inspection costs of $8,000/km for internally FBE-coated pipes and $4,000/km for bare steel pipes. Given a pipeline length of 100 km:

- The annual OPEX for bare pipes is $800,000.
- The annual OPEX for coated pipes is $400,000.

Using a 10%, discount rate over a 25-year service life:

- The present value (PV) of inspection costs for bare pipes is $7,261,632.
- The PV of inspection costs for coated pipes is $3,630,816.

C. Energy consumption

Chile's industrial electricity pricing incorporates generation costs, transmission fees, and distribution charges. The generation component reflects marginal system costs influenced by fossil fuel prices and renewable penetration. Transmission and distribution costs remain regulated, with recent tariff adjustments adding complexity to pricing calculations.

For large industrial consumers, July 2024 data showed an average rate of $128/MWh. This baseline industrial rate of $128/MWh requires adjustment through three critical factors: fuel price volatility (45.77% fossil dependency amid declining coal production), renewable integration costs ($5-8/MWh for grid stability with 27% solar/wind penetration), and transmission constraints ($3-12/MWh regional differentials). Chile's 2024 Tariff Stabilization Law further modifies pricing via:

- Generation component adjustments. (+15% from 2022 baseline, CPI-indexed).
- Debt servicing surcharge ($0.02/kWh until 2035).
- Transmission upgrades. ($1.2/MWh fee).

This comprehensive adjustment framework elevates the 2024 effective rate to:

$$P_{2024} = (128 \cdot 1.15) + (0.02 \cdot 1000) + 1.2 = 168.4 \frac{\$}{\text{MWh}}$$

It is important to note that the energy costs for the Chilean mining sector costs rose from $85/MWh (2015) to $112/MWh (2024), 40% above Peruvian competitors.

TABLE 9.HISTORICAL PRICE CONTEXT

Year	*Avg. Industrial Rate*	*Key Influencers*
2022	$145/MWh	Coal phase-out begins
2023	$158/MWh	Gas price spike
2024	$168/MWh (adjusted)	Debt repayment initiated
2025	$175/MWh (projected)	Full tariff normalization

This analysis adopts a projected rate of P = $175/MWh for years 2025 onwards. This rate is used in (4) which calculates de cost of energy consumed by the pipeline project pump(s).

$$C = \frac{\rho \cdot g \cdot Q \cdot (H_f + H_z) \cdot t \cdot P}{\eta} \quad (4)$$

Where ρ is fluid density; g is the gravitational acceleration; Q is the volumetric flow rate; $H_t = h_f + h_z$ is the total head loss due to friction losses (h_f) plus elevation head (**h_z = 1000 m**); η is the pump efficiency (**82%**) and t is the annual operating time (**8400 hours**).

To estimate energy required to overcome friction losses in the pipeline the Darcy-Weisbach equation (5) is used.

$$h_f = \text{f} \cdot \frac{L}{D} \cdot \frac{v^2}{2g} \quad (5)$$

Where h_f is the head loss due to friction losses in the pipeline; f is the Darcy-Weisbach friction factor, a dimensionless parameter representing energy loss due to friction in a pipe; L is the length of the pipeline; v is the velocity of the fluid; g is the acceleration due to gravity; and

D is the inside diameter of the pipeline, where larger diameters reduce friction losses by lowering fluid velocity for a given flow rate.

To calculate the Darcy-Weisbach friction factor f, the Colebrook-White equation is utilized.

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{k}{3.7\cdot D} + \frac{2.51}{Re\cdot\sqrt{f}}\right) \tag{6}$$

Where f is the Darcy-Weisbach friction factor; k is the pipe's roughness height and D is the pipe inside diameter; Re is the Reynolds number; and the logarithmic term accounts for both surface roughness and viscous effects in turbulent flow. The equation is implicit in f and requires iterative or numerical methods to solve.

Bare Pipe Case Calculations

For the bare pipe case, on year 1, the Reynolds number is calculated as using equation:

$$Re = \frac{\rho\cdot v\cdot D}{\mu} \tag{7}$$

Where ρ is the fluid density (**1030 kg/m³**), v is the fluid velocity on year 1 (**1.901 m/s**) derived from the flow ratio of **0.7 m³/s**, *D* is the pipe inside diameter (**0.68464m**) for wall thickness of **13.28** mm on year 1, μ is the dynamic viscosity (**0.0013 Pa·s**). Substituting values, $Re = 1{,}031{,}430$. Again, substituting values on (6):

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{0.00007}{3.7\cdot 0.68464} + \frac{2.51}{1{,}031{,}430\cdot\sqrt{f}}\right) \tag{8}$$

Solving for f using the Newton-Raphson iterative numerical technique which converges to f = 0.013396. Substituting values on eq (3):

$$h_f = 0.013396\cdot\frac{100000}{0.68464}\cdot\frac{1.901^2}{2\cdot 9.81} = 360.69\text{ m} \tag{9}$$

Again, substituting values on eq (2):

$$C_{bare\ yr\ 1} = \frac{1030\cdot 9.81\cdot 0.7\cdot(360.69+1000)\cdot 8400\cdot 0.000175}{0.0013} \tag{10}$$
$$= \$17{,}247{,}242$$

For the bare pipe case, previous calculation procedure is repeated for the next 25 years, decreasing the wall thickness by the design corrosion rate of 0.15 mm/yr; from 13.28 mm on year 1 to 9.53 mm on year 25; and increasing the pipe roughness from 0.068**.** mm on first year to 0.720 mm by the end of year 25.

Coated Pipe Case Calculations

Same procedure is done for the coated pipe case, only this time, wall thickness is maintained at 0.015 mm, and pipe roughness increases from 0.015 mm on first year to 0.035mm by year 25 end.

Results for both the bare and coated pipe are listed on Annex A – Energy Consumption Calculations.

TABLE 10. ELECTRICITY CONSUMPTION PRESENT VALUE COMPARISON

Energy Cost PV	Bare Pipe	Coated Pipe	Difference
Friction	\$48,965,594	\$35,957,717	\$13,007,877
Elevation	\$115,054,517	\$115,054,517	\$0

Since the elevation cost is unrelated to corrosion and equal to both strategies, it will not be considered in the analysis.

VI. RESULTS

A. CAPEX Comparison

The corrosion allowance strategy requires 27.9% (\$4.58M) more steel mass than coated systems, increasing initial CAPEX to \$21.07M.

While coated pipes show lower baseline steel costs (\$15.20M), field joint coating adds \$8.33M (33.5% of total CAPEX) due to robotic application requirements.

Notably, field-applied joint coatings cost 1,514× more per m² than shop FBE (\$1,000/joint vs \$6/m²), despite protecting only 0.42% of total surface area.

This cost disparity stems from complex field logistics and inferior coating quality (2.8× more defects vs shop FBE).

B. OPEX Comparison

Bare pipe systems incur \$17.49M higher OPEX over 25 years (PV discounted at 10%):

- **Chemical Inhibitors**: \$10.22M PV (46% of bare pipe OPEX)
- **Energy Penalty**: \$13.01M PV from increased friction (0.72mm roughness vs 0.035mm coated)
- **Inspections**: \$3.63M PV savings from coated systems' longer intervals

Coated systems eliminate inhibitor costs while maintaining 92% lower surface roughness, reducing pumping energy by 26.6% (\$35.96M vs \$48.97M PV).

C. Lifecycle Cost Analysis Results

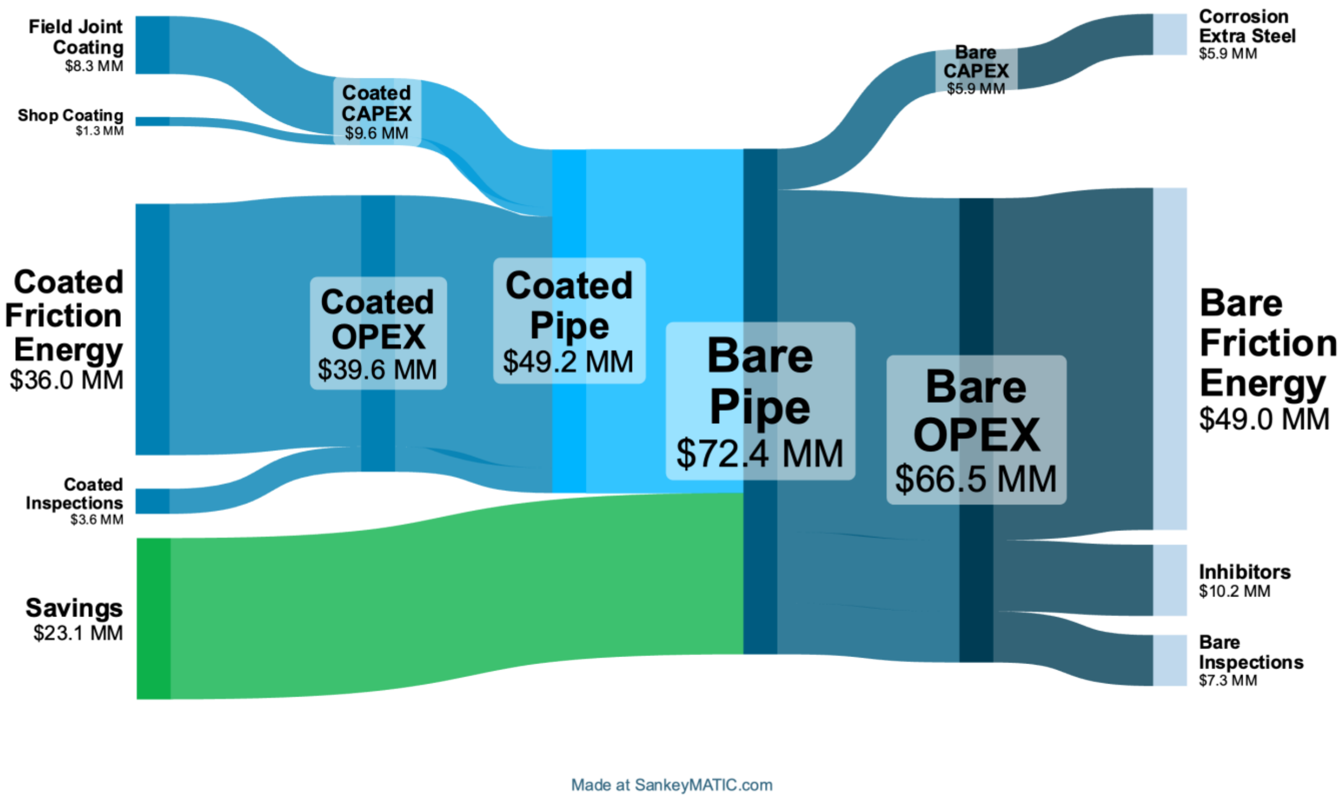
Total 25-year expenditures reveal:

- **Bare Pipe**: \$72.32M (CAPEX 8.1%, OPEX 91.9%)
- **Coated Pipe**: \$49.23M (CAPEX 19.6%, OPEX 80.4%)

Coated systems demonstrate \$23.09M (31.9%) lifecycle savings despite 64.3% higher CAPEX. The break-even point occurs at Year 14 considering time-valued costs.

Table 11. Total Expenditure

		Corrosion Strategy		
Type	**Expenditure Category**	**Bare**	**Coated**	**Coated Savings**
CAPEX	Extra Steel for Corrosion	$5,869,705		$5,869,705
CAPEX	Field Joint Coating		$8,334,000	-$8,334,000
CAPEX	Shop-applied Coating		$1,304,653	-$1,304,653
OPEX	Corrosion Inhibitors	$10,223,565		$10,223,565
OPEX	Friction Energy	$48,965,594	$35,957,717	$13,007,877
OPEX	Inspections	$7,261,632	$3,630,816	$3,630,816
	Total CAPEX	$5,869,705	$9,638,653	-$3,768,948
	Total OPEX	$66,450,791	$39,588,533	$26,862,258
	Total Expenditure	**$72,320,496**	**$49,227,186**	**$23,093,309**



VII. Discussion

A. Interpretation of Results

The $13.01M energy savings from coated systems exceed their $8.33M field coating costs, validating epoxy's hydraulic efficiency. However, 61% of coating failures originate from field joints - a critical vulnerability requiring quality control investments. The 10% discount rate amplifies OPEX savings significance, making coated systems financially preferable despite higher initial outlays.

B. Considerations

- **Energy Price Sensitivity**: 1% increase in electricity rates adds $350k/year OPEX to bare systems
- **Coating Durability**: 5-year reduction in coating service life would erase 22% of calculated savings
- **Altitude Factors**: At 3,000m+ elevations, bare pipe's 3.75mm corrosion allowance may be insufficient against pitting corrosion

C. Comparison with Existing Literature

Our 31.9% lifecycle savings align with NACE SP21430-2023 findings (28-34% coating advantages) but exceed CAPP's 2018 estimates (22-25%).

Discrepancies stem from Chile's unique $175/MWh energy costs vs North American $85-110/MWh benchmarks.

The field joint cost ratio (6.4× steel cost) matches TYHOO Group's 2023 project audits but contradicts IEC's 2017 prediction of 4.8× ratios.

VIII. SUMMARY

Corrosion Allowance: While simpler to implement, this strategy incurs higher material, energy, and maintenance costs over the pipeline's lifecycle. It is less adaptable to localized corrosion risks and relies heavily on chemical inhibitors, which pose environmental concerns.

Internally Coated Pipe (FBE): Offers better long-term cost savings due to reduced energy consumption and maintenance needs. However, it requires careful application and quality control during installation, particularly at field joints.

Overall, the internally coated pipe strategy demonstrates superior lifecycle performance but involves higher initial technical complexity.

Aspect	**Corrosion Allowance**	**Internally Coated Pipe (FBE)**
Capital Expenditure (CAPEX)	Requires 29.6% more steel due to increased wall thickness (3.75 mm), adding $4,583,412 to initial costs	Lower initial steel cost; additional $1,304,653for shop coating and $8,334,000 for field joint coating.
Operational Costs (OPEX)	- High energy costs due to increased friction from rougher pipe surface and smaller internal diameter. - Requires corrosion inhibitors, adding $11.84 million in present value over 25 years.	- Smoother surface reduces friction, saving $7.1 million in energy costs. - No need for inhibitors, reducing complexity and cost.
Maintenance	- Frequent inspections and repairs due to progressive wall thinning. - Higher inspection costs ($5.08 million over 25 years).	- Less frequent inspections (every 5-10 years) and lower costs ($2.54 million over 25 years).
Durability	Relies on material thickness; prone to localized pitting corrosion that may lead to failures.	Effective barrier against corrosion; weak points at field joints if improperly coated.
Technical Challenges	Simple design but less adaptable to varying corrosion rates or localized damage.	Requires specialized application techniques; challenges with field joint coating quality.
Energy Efficiency	Higher friction losses increase pumping energy consumption by $7.1 million in present value.	Improved hydraulic efficiency reduces energy consumption.

APPENDIX A

Table 12. Bare pipe Electricity cost calculations.

Analyzed **case: Bare. Initial wall thickness = 13.28 mm; year 25 wall thickness = 9.53 mm. Initial pipe roughness = 0.07 mm; year 25 pipe roughness = 0.72 mm. Fixed parameters: Elevation head = 1000 m; pump efficiency = 82%; energy cost = 175 $/MWh; outside diameter = 28''; flow rate = 700 L/s; density of water = 1030 kg/m3; viscosity of water = 0.0013 Pa·s**

Yr	Pipe roughness [mm]	Interior Diameter [mm]	Wall thickness [mm]	Fluid Velocity [m/s]	Friction factor f [ ]	Head Loss [m]	Pump Friction [kW]	Pump Elevation [kW]	Electricity Friction [M$]	Electricity Elevation [M$]
1	0.100	682.140	14.53000	1.915	0.014030	269.32	2322	8623	$3,413,697	$12,675,334
2	0.108	682.557	14.32167	1.913	0.014180	271.37	2340	8623	$3,439,685	$12,675,334
3	0.117	682.973	14.11333	1.911	0.014325	273.31	2357	8623	$3,464,266	$12,675,334
4	0.125	683.390	13.90500	1.908	0.014466	275.14	2372	8623	$3,487,545	$12,675,334
5	0.133	683.807	13.69667	1.906	0.014602	276.89	2387	8623	$3,509,618	$12,675,334
6	0.142	684.223	13.48833	1.904	0.014734	278.54	2402	8623	$3,530,569	$12,675,334
7	0.150	684.640	13.28000	1.901	0.014862	280.11	2415	8623	$3,550,473	$12,675,334
8	0.158	685.057	13.07167	1.899	0.014987	281.60	2428	8623	$3,569,398	$12,675,334
9	0.167	685.473	12.86333	1.897	0.015108	283.02	2440	8623	$3,587,405	$12,675,334
10	0.175	685.890	12.65500	1.895	0.015227	284.38	2452	8623	$3,604,550	$12,675,334
11	0.183	686.307	12.44667	1.892	0.015342	285.66	2463	8623	$3,620,882	$12,675,334
12	0.192	686.723	12.23833	1.890	0.015455	286.89	2474	8623	$3,636,447	$12,675,334
13	0.200	687.140	12.03000	1.888	0.015565	288.06	2484	8623	$3,651,288	$12,675,334
14	0.208	687.557	11.82167	1.885	0.015673	289.18	2493	8623	$3,665,442	$12,675,334
15	0.217	687.973	11.61333	1.883	0.015778	290.24	2503	8623	$3,678,945	$12,675,334
16	0.225	688.390	11.40500	1.881	0.015881	291.26	2511	8623	$3,691,830	$12,675,334
17	0.233	688.807	11.19667	1.879	0.015983	292.23	2520	8623	$3,704,127	$12,675,334
18	0.242	689.223	10.98833	1.876	0.016082	293.16	2528	8623	$3,715,863	$12,675,334
19	0.250	689.640	10.78000	1.874	0.016179	294.04	2535	8623	$3,727,065	$12,675,334
20	0.258	690.057	10.57167	1.872	0.016275	294.88	2543	8623	$3,737,757	$12,675,334
21	0.267	690.473	10.36333	1.869	0.016368	295.69	2550	8623	$3,747,962	$12,675,334
22	0.275	690.890	10.15500	1.867	0.016461	296.46	2556	8623	$3,757,699	$12,675,334
23	0.283	691.307	9.94667	1.865	0.016551	297.19	2563	8623	$3,766,990	$12,675,334
24	0.292	691.723	9.73833	1.863	0.016640	297.89	2569	8623	$3,775,852	$12,675,334
25	0.300	692.140	9.53000	1.860	0.016728	298.56	2574	8623	$3,784,304	$12,675,334
Bare Pipe Case. Present Value (annual OPEX discounted at 10% rate)									$32,323,586	$115,054,517

Table 13. Coated pipe Electricity cost calculations

Analyzed case: Coated. Initial wall thickness = 9.53 mm; year 25 wall thickness = 9.53 mm. Initial pipe roughness = 0.02 mm; year 25 pipe roughness = 0.04 mm. Fixed parameters: Elevation head = 1000 m; pump efficiency = 82%; energy cost = 175 $/kWh; outside diameter = 28"; flow rate = 700 L/s; density of water = 1030 kg/m3; viscosity of water = 0.0013 Pa·s

Yr	Pipe roughness [mm]	Interior Diameter [mm]	Wall thickness [mm]	Fluid Velocity [m/s]	Friction factor f	Head Loss [m]	Pump Friction [kW]	Pump Elevation [kW]	Electricity Friction [M$]	Electricity Elevation [M$]
1	0.0100	692.140	9.53000	1.860	0.011929	212.91	1836	8623	$2,698,730	$12,675,334
2	0.0117	692.140	9.53000	1.860	0.011980	213.83	1844	8623	$2,710,311	$12,675,334
3	0.0133	692.140	9.53000	1.860	0.012031	214.73	1852	8623	$2,721,728	$12,675,334
4	0.0150	692.140	9.53000	1.860	0.012080	215.61	1859	8623	$2,732,985	$12,675,334
5	0.0167	692.140	9.53000	1.860	0.012130	216.49	1867	8623	$2,744,089	$12,675,334
6	0.0183	692.140	9.53000	1.860	0.012178	217.35	1874	8623	$2,755,043	$12,675,334
7	0.0200	692.140	9.53000	1.860	0.012226	218.21	1882	8623	$2,765,852	$12,675,334
8	0.0217	692.140	9.53000	1.860	0.012273	219.05	1889	8623	$2,776,522	$12,675,334
9	0.0233	692.140	9.53000	1.860	0.012319	219.88	1896	8623	$2,787,055	$12,675,334
10	0.0250	692.140	9.53000	1.860	0.012365	220.70	1903	8623	$2,797,457	$12,675,334
11	0.0267	692.140	9.53000	1.860	0.012411	221.51	1910	8623	$2,807,731	$12,675,334
12	0.0283	692.140	9.53000	1.860	0.012456	222.31	1917	8623	$2,817,880	$12,675,334
13	0.0300	692.140	9.53000	1.860	0.012500	223.10	1924	8623	$2,827,908	$12,675,334
14	0.0317	692.140	9.53000	1.860	0.012544	223.89	1930	8623	$2,837,819	$12,675,334
15	0.0333	692.140	9.53000	1.860	0.012587	224.66	1937	8623	$2,847,616	$12,675,334
16	0.0350	692.140	9.53000	1.860	0.012630	225.42	1944	8623	$2,857,302	$12,675,334
17	0.0367	692.140	9.53000	1.860	0.012672	226.18	1950	8623	$2,866,879	$12,675,334
18	0.0383	692.140	9.53000	1.860	0.012714	226.93	1957	8623	$2,876,351	$12,675,334
19	0.0400	692.140	9.53000	1.860	0.012756	227.66	1963	8623	$2,885,721	$12,675,334
20	0.0417	692.140	9.53000	1.860	0.012797	228.40	1969	8623	$2,894,990	$12,675,334
21	0.0433	692.140	9.53000	1.860	0.012837	229.12	1976	8623	$2,904,163	$12,675,334
22	0.0450	692.140	9.53000	1.860	0.012877	229.84	1982	8623	$2,913,240	$12,675,334
23	0.0467	692.140	9.53000	1.860	0.012917	230.54	1988	8623	$2,922,224	$12,675,334
24	0.0483	692.140	9.53000	1.860	0.012956	231.25	1994	8623	$2,931,118	$12,675,334
25	0.0500	692.140	9.53000	1.860	0.012995	231.94	2000	8623	$2,939,924	$12,675,334
			Bare Pipe Case. Present Value (annual OPEX discounted at 10% rate)						**$25,223,188**	**$115,054,517**

TABLE 14. COST COMPONENTS FOR ROBOTIC FIELD COATING

Cost Component	***Cost per Joint***
Mobilization of Crew & Equipment	$22.08
Demobilization of Crew & Equipment	$13.80
Personnel & Robotic Equipment	$505.08
Pre-blasting Personnel & Equipment	$149.04
Internal Coating Application	$181.24
Pipe-End Pre-blasting	$48.76
Total Cost per Joint	$1,000.00

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