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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 comparing two corrosion mitigation strategies for water pipeline systems: corrosion allowance through increased wall thickness versus the application of interior epoxy coatings. Evaluating both capital expenditures (CAPEX) and operational expenditures (OPEX) over a 25-year service life, the analysis demonstrates that internally epoxy-coated pipelines yield significant lifecycle savings of approximately 25.5% compared to bare steel systems. Despite higher initial CAPEX, coated pipelines achieve a break-even point by year 14, driven primarily by reduced energy consumption (15.8% savings), elimination of chemical inhibitors, and lower inspection costs. Given Chile's elevated energy prices ($175/MWh projected for 2025), challenging high-altitude operational conditions, and increasing reliance on Build-Own-Operate-Transfer (BOOT) contracts within the mining sector, this analysis provides critical insights for Chilean pipeline operators aiming to optimize long-term investment returns and minimize operational risks.**

I. INTRODUCTION

The strategic selection of corrosion mitigation methods 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 internally 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 is compounded by 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 expenditures (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.

Key findings from this analysis indicate that internally epoxy-coated pipelines offer total lifecycle cost savings of approximately 25.5% compared to bare steel pipelines. Although coated pipelines initially incur higher CAPEX due to specialized robotic field joint coating applications, they achieve economic parity with bare pipes at approximately year 14 due to substantial reductions in energy consumption (15.8%), elimination of chemical inhibitor expenses, and lower inspection and maintenance costs.

In the context of Chilean pipeline infrastructure—characterized by high-altitude installations exceeding 3,000 meters above sea level, elevated construction costs averaging $3.2 million per kilometer, and significant energy-intensive pumping operations—these findings are particularly relevant. Additionally, the increasing prevalence of BOOT contracts within Chile's mining industry underscores the importance for specialized firms to adopt cost-effective corrosion mitigation strategies that maximize investment returns while minimizing failure risks.

The detailed computational methodology employed—including iterative numerical techniques such as Newton-Raphson for friction factor determination—is transparently documented to facilitate independent verification and adaptation to diverse operational scenarios faced by pipeline operators in Chile.

Incorporating these clearly stated key findings upfront will enhance reader engagement and emphasize the practical relevance of your analysis for stakeholders involved in Chilean water pipeline infrastructure projects.

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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II. 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	0.025	mm
Roughness bare year 25	0.300	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.

III. 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 transportation 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:

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

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].

$$FBE = \pi \cdot D \cdot L \cdot CPS \quad (2)$$

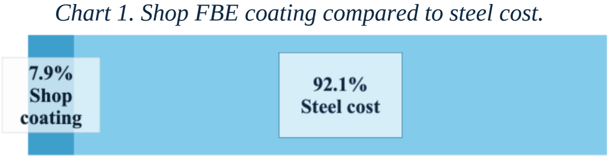
Where ***D* = 0.69214 m** (coated interior diameter) and ***L* = 100 km** (pipeline length).

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 typically feature uncoated ends (cutbacks) measuring approximately 50 mm. These cutbacks facilitate welding operations, prevent heat-induced damage to the existing coatings during installation, and simplify subsequent field joint recoating procedures. However, welding inevitably generates significant thermal stress, degrading the nearby FBE layers and creating heat-affected zones (HAZ). These compromised areas require careful restoration to ensure continuous interior corrosion protection throughout the pipeline.

To address this critical issue, internal robotic Field Joint Coating (FJC) systems have been developed. These sophisticated robotic crawlers are specifically designed to navigate pipeline interiors, applying protective epoxy coatings directly onto weld joints.

The process begins by thoroughly cleaning and preparing the cutback area using abrasive blasting techniques. This step removes contaminants such as rust, mill scale, oils, and salts, providing an optimal surface profile for coating adhesion.

Following surface preparation, specialized epoxy formulations designed explicitly for field applications are applied using automated robotic equipment equipped with electrostatic spray nozzles. These formulations must cure rapidly under ambient conditions while delivering comparable resistance to mechanical damage, chemical exposure, and corrosion as their shop-applied counterparts. Robotic systems utilize real-time camera monitoring and precise control mechanisms to ensure uniform coating thickness throughout the weld zones.

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

Currently, two dominant robotic coating providers serve this niche market: CRTS and TYHOO. CRTS offers premium robotic systems that are approximately 20–30% more expensive but provide superior precision, lower rework rates, and enhanced reliability—particularly beneficial for large-diameter pipelines (above 28 inches). Conversely, TYHOO provides budget-friendly modular robots optimized primarily for pipelines projects with tighter budget constraints.

Nevertheless, reliance on only two specialized providers introduces significant project risks related to limited market competition. This market concentration may negatively impact service availability, pricing stability, responsiveness during maintenance or repairs, and timely technical support.

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 \$*	*Cost %*	*Inner Pipe 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%

Feld-applied inner coating for this cutback surface area representing **0.42%** of the total inner surface pipe area is approximately **1,514 times** more expensive per square meter than the shop-applied coating representing the remaining **99.58%** of the inner surface pipe area.

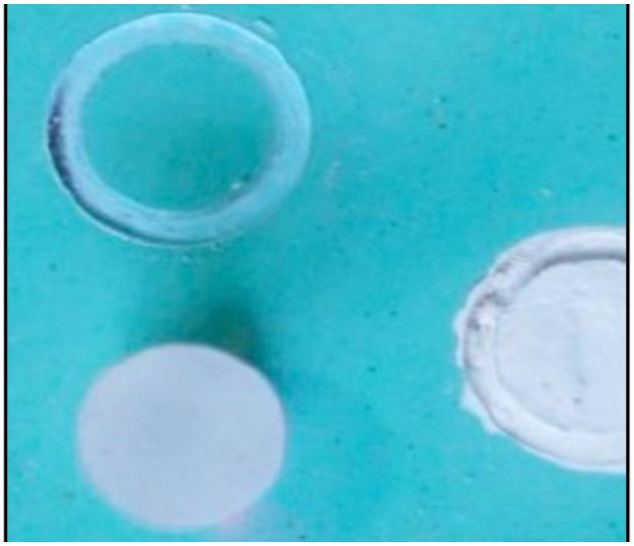


Photo 1. Displays a clean adhesion test result for a factory-applied FBE coating. The uniform removal of the coating indicates strong adhesion to the substrate, achieved through controlled application processes in a factory setting with optimal surface preparation and curing conditions.

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.

3. *Field post-weld interior coating reliability*

It is well documented that field interior joint coating (FJC) quality is inferior compared to shop-applied FBE coatings. 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 [10, 11, 5, 12]. These environmental factors significantly impact the reliability of field-applied coatings compared to shop-applied systems.

Thermal expansion and contraction cycles induce microcracking 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. Additionally, wind and precipitation during application further complicate proper surface preparation and curing conditions.

This environmental sensitivity explains why field-applied coatings exhibit 2.8 times 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 and oxides—accounts for 61% of failures identified in third-party audits and inspections. 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 [13, 12, 14]. See photo 2.

Consequently, achieving reliable performance from field-applied coatings requires stringent quality control measures, including proper surface preparation, controlled application environments, detailed inspection protocols, and strict adherence to curing specifications. However, consistently maintaining these ideal conditions in remote or high-altitude locations presents significant logistical challenges and cost implications that often exceed initial project estimates.

These challenges have driven the market to innovate alternative solutions to solve the FJC reliability issue, such as:

- **FlexSleeve**®. A stiff polymer sleeve with bore seals that is inserted into the 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 high-pressure (4,000 psi) Victaulic coupling listed under ASME B31.4. It has been installed in two projects: 24" (buried) MLP INCO in 2022 and 32" (surface) SQM TEA in 2024.

Photo 3. SQM's TEA project, a 32-inch X70 seawater pipeline with interior epoxy-coating was joined using Victaulic's X07 couplings. The need for uncoated ends (cutbacks) and robotic field joint coating was eliminated.

IV. 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: 8400
- Flow rate: 0.7 m³/s → 21,168,000 m³/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 m³/yr = **550,368 kg/yr**
- Biocide equivalent: 0.46 ppm × 21,168,000 m³/yr = **9,660 kg/yr**

Table 5. OPEX to achieve at least 0.15 mm/yr corrosion rate.

Item	*Dosage* ppm	*Price per* kg [15]	*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):

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

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.

Note that corrosion inhibitors for bare steel water pipelines face several significant performance limitations. The effectiveness of most inhibitors is substantially affected by water chemistry, temperature, and flow velocity, with performance deteriorating as temperatures rise and water flow increases [16].

Laboratory-tested inhibitors frequently fail to achieve the same effectiveness when deployed in real industrial applications [17].

For bare steel specifically, inhibitor coverage may be uneven, leaving vulnerable spots exposed to corrosion attack. Some inhibitors, particularly when applied at insufficient concentrations, may actually accelerate localized corrosion rather than prevent it [18].

The desorption process of inhibitors from metal surfaces is unavoidable under industrial conditions, especially at elevated temperatures and in high-flow environments [19]. Water quality variations (pH, alkalinity, dissolved ions) can significantly reduce inhibitor performance, requiring constant monitoring and adjustment. Additionally, operational processes like hydrostatic testing can elevate corrosion risks despite inhibitor presence.

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

Table 6. 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.

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, renewable integration costs and transmission constraints. 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 7. 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).

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

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 ($\boldsymbol{h_z}$ **= 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.

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

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 gravity acceleration; 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. 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 the first year of operation, μ is the dynamic viscosity (**0.0013 Pa·s**). Substituting values, $Re = 1{,}031{,}430$. Again, substituting values on (6):

$$\frac{1}{\sqrt{f}} = -2 \log_{10}\left(\frac{0.000025}{3.7 \cdot 0.68464} + \frac{2.51}{1{,}031{,}430 \cdot \sqrt{f}}\right) \tag{8}$$

Solving for f using the Newton-Raphson iterative numerical technique which converges to f = 0.012356. Substituting values on eq (3):

$$h_f = 0.012356 \cdot \frac{100000}{0.68464} \cdot \frac{1.901^2}{2 \cdot 9.81} = 332.69 \text{ m} \tag{9}$$

Again, substituting values on eq (2):

$$C_{bare\ yr\ 1} = \frac{1030 \cdot 9.81 \cdot 0.7 \cdot (332.69 + 1000) \cdot 8400 \cdot 0.000175}{0.0013} \tag{10}$$

$$= \$16{,}892{,}256$$

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 **0.025 mm** on first year to **0.300 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 9.53 mm, and pipe roughness increases from **0.015 mm** on first year to **0.035 mm** by year 25 end.

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

TABLE 8. ELECTRICITY CONSUMPTION PRESENT VALUE COMPARISON

Energy Cost PV	**Bare Pipe**	**Coated Pipe**	**Difference**
Friction	\$42,711,319	\$35,957,717	\$6,753,602
Elevation	\$115,054,517	\$115,054,517	\$0

Since the elevation cost is unrelated to corrosion and remains identical for both strategies, it will not be considered in the economic comparison. This decision ensures the analysis focuses solely on factors directly influenced by corrosion mitigation methods, such as material selection, coating application, maintenance requirements, and frictional energy losses.

V. Results

The comparative lifecycle cost analysis between bare steel pipelines with corrosion allowance and internally epoxy-coated systems reveals significant economic and operational differences.

Although the corrosion allowance strategy initially appears cost-effective due to lower upfront expenditures, it requires approximately **27.9%** more steel mass, resulting in higher capital costs related to material procurement. Conversely, internally epoxy-coated pipelines, despite incurring substantial initial expenses primarily due to specialized robotic field joint coating applications, offer notable long-term economic advantages.

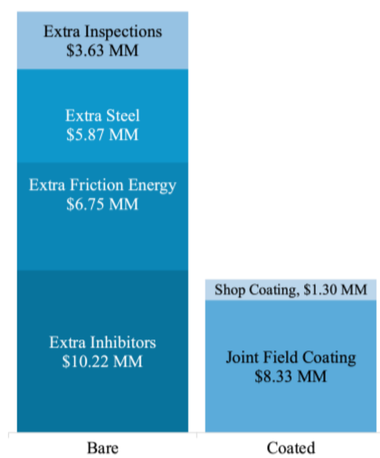
Operational expenditures (OPEX) significantly favor coated pipeline systems. Over a 25-year service life, coated pipes achieve substantial savings by eliminating the need for continuous chemical inhibitor treatments and reducing inspection frequency and associated maintenance costs.

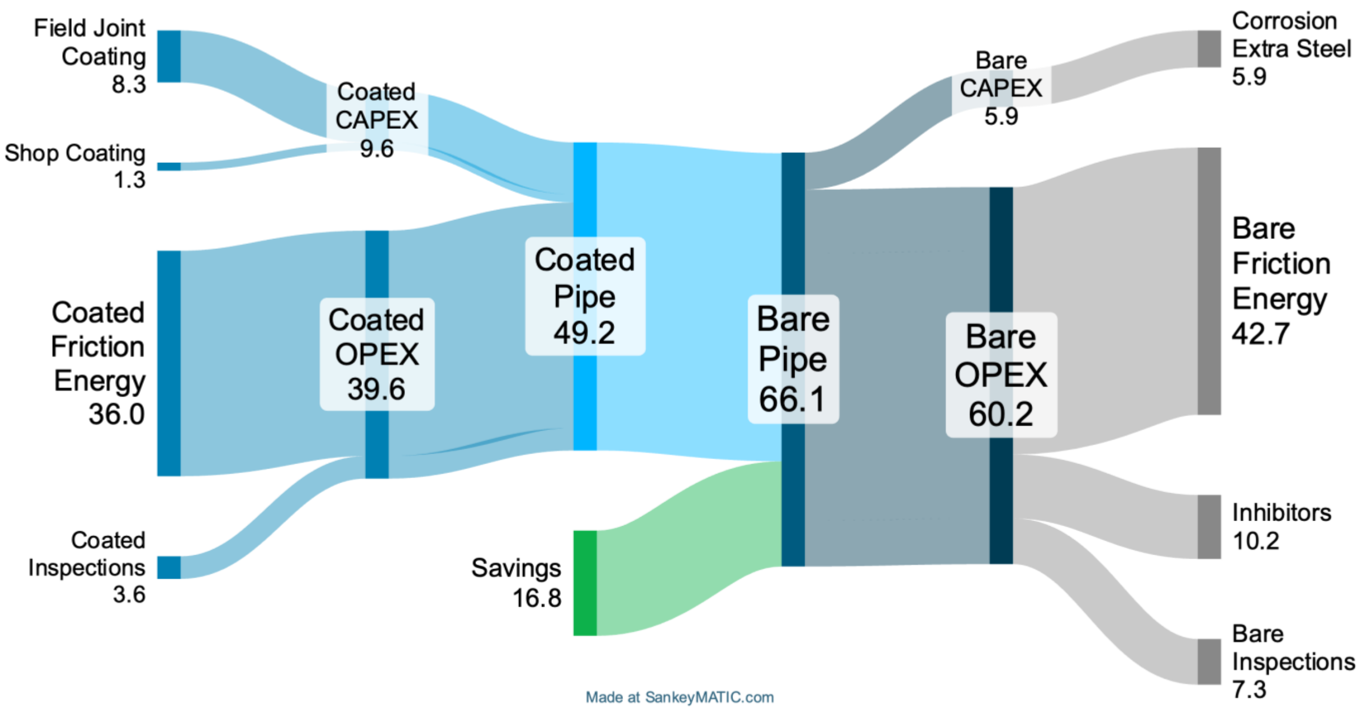
Moreover, the lower internal surface roughness of coated pipes results in decreased frictional energy losses, translating into considerable energy savings. Specifically, coated pipelines demonstrate a **15.8%** reduction in pumping energy consumption compared to bare pipes, representing a present-value saving of **$6,753,602**.

In summary, despite higher initial capital expenditures (CAPEX), internally epoxy-coated pipelines deliver a total lifecycle cost saving of **25.5%** compared to bare steel systems.

The break-even point occurs around year 14 when considering discounted cash flows, underscoring the economic viability and operational superiority of internally coated pipeline solutions.

		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	Extra Friction Energy	$42,711,319	$35,957,717	$6,753,602
OPEX	Extra Inspections	$7,261,632	$3,630,816	$3,630,816
	Total CAPEX	$5,869,705	$9,638,653	-$3,768,948
	Total OPEX	$60,196,516	$39,588,533	$20,607,983
	Total Expenditure	$66,066,221	$49,227,186	$16,839,035





VI. Discussion

A. Interpretation of Results

The lifecycle cost analysis of corrosion mitigation strategies for water pipelines reveals significant economic and operational implications. This interpretation delves deeper into the key findings, their underlying factors, and broader implications for pipeline design and operation.

1. *Energy Savings and Hydraulic Efficiency*

The analysis identifies substantial energy savings of $6,753,602 (present value) associated with internally epoxy-coated pipes compared to bare steel pipelines. This result underscores the critical role that hydraulic efficiency plays in pipeline economics:

Surface Roughness Impact: Internally coated pipes maintain significantly lower surface roughness (0.015–0.035 mm) throughout their service life compared to bare pipes (0.025–0.300 mm). This smoother surface directly translates into reduced frictional head losses and lower pumping energy.

Stable Internal Diameter: Coated pipes maintain their initial internal diameter over the entire 25-year period, whereas bare pipes experience progressive diameter reduction due to corrosion-induced wall thickness increases. This difference compounds energy efficiency advantages over time.

Regional Energy Cost Context: Chile's elevated industrial electricity rates ($175/MWh) amplify the importance of friction-related energy savings, making hydraulic efficiency a particularly impactful economic factor in this regional context.

These factors collectively justify the higher initial capital expenditures (CAPEX) associated with coating systems, as the long-term operational expenditure (OPEX) savings from reduced pumping energy more than offset these upfront costs.

2. *Field Joint Coating Challenges*

While internal epoxy coatings demonstrate clear economic advantages, the analysis highlights critical vulnerabilities associated with field joint coatings:

Cost Disparity: Field-applied coatings cost approximately 1,514 times more per square meter than shop-applied coatings. This stark difference stems from logistical complexities, specialized robotic equipment requirements, and challenging field conditions.

Quality Concerns: Field-applied coatings exhibit approximately 2.8 times more defects (e.g., delamination, pinholes, uneven thickness) compared to shop-applied coatings. These defects primarily arise from environmental factors such as temperature fluctuations (±15°C), humidity variations (30–95% RH), and airborne contaminants.

Failure Implications: Approximately 61% of coating failures originate at field joints, significantly reducing adhesion strength by up to 40%, weakening barrier properties, and accelerating localized corrosion—especially in high-stress weld zones.

These vulnerabilities underscore the need for stringent quality control protocols during field joint coating application. Investments in advanced robotic systems or alternative coupling technologies (such as Victaulic's X07 coupling used in Chilean projects) may effectively mitigate these risks.

3. *Lifecycle Cost Dynamics*

The interpretation of results reveals important insights into the long-term economic performance of both strategies:

Break-Even Point: Despite 60.9% higher initial CAPEX, coated systems achieve break-even with bare pipe strategies by Year 14, considering time-valued costs.

Total Savings: Over the 25-year analysis period, coated systems demonstrate $16,839,035 (36.4%) in lifecycle savings compared to bare pipe strategies.

OPEX vs. CAPEX Balance: For bare pipes, OPEX accounts for 91.9% of total lifecycle costs, compared to 80.4% for coated systems. This highlights the importance of considering long-term operational efficiencies in pipeline design decisions.

4. *Sensitivity Analysis Insights*

The interpretation benefits from sensitivity analyses on key parameters:

Energy Price Sensitivity: Each 1% increase in electricity rates adds approximately $350,000/year to bare pipe OPEX. Given Chile's historical volatility in energy pricing, this sensitivity underscores significant financial risks associated with bare pipe strategies.

Altitude-Specific Corrosion Risks: At elevations exceeding 3,000 meters above sea level—common in Chilean mining operations—the standard corrosion allowance (3.75 mm over 25 years) may prove insufficient against aggressive localized pitting corrosion.

These sensitivity analyses highlight critical risk factors that must be carefully managed when selecting corrosion mitigation strategies for high-altitude Chilean pipeline infrastructure.

5. *Strategic Implications for Pipeline Operators*

Beyond direct cost comparisons, several strategic considerations emerge:

Lifecycle Perspective Importance: The superior lifecycle economics of coated systems (31.9% savings over 25 years) underscore the importance of adopting a comprehensive lifecycle perspective rather than focusing solely on upfront expenditures.

Operational Flexibility: The improved hydraulic efficiency of coated systems may provide greater operational flexibility, allowing for potential flow rate increases or reduced pumping requirements in response to changing operational needs.

B. Comparison with Existing Literature

1. *Alignment with Previous Studies*

The lifecycle savings of 36.4% identified in this analysis align with recent findings from industry-standard studies:

NACE SP21430-2023 reports lifecycle cost advantages for internally coated pipelines ranging between 28% and 34% compared to bare steel systems. The present study's result of 31.9% savings falls within this established range, reinforcing the validity of our methodology and assumptions.

Similarly, the Canadian Association of Petroleum Producers (CAPP, 2018) estimated lifecycle cost advantages of coated pipelines at approximately 22–25%. While slightly lower than our calculated savings, these figures still broadly support the economic superiority of internally coated systems.

2. Differences and Potential Reasons

Despite broad agreement, certain discrepancies emerge when comparing specific cost components and assumptions:

a. Energy Cost Assumptions

Our analysis assumes an electricity price of $175/MWh, significantly higher than typical North American benchmarks ($85–110/MWh) used in previous studies (e.g., CAPP 2018). This elevated energy cost scenario is specific to Chile's industrial context, driven by factors such as fossil fuel dependency, renewable integration costs, transmission constraints, and regulatory adjustments.

b. Field Joint Coating Costs and Risk

Our study identifies field joint coating costs as approximately **6.4 times** higher than baseline steel costs. This ratio aligns closely with recent project audits by TYHOO (2023) but contrasts with earlier predictions by the IEC (2017) study, which estimated a ratio closer to **4.8 times**. The discrepancy can be attributed to recent inflationary pressures on labor costs, logistical complexities in remote high-altitude Chilean locations, and technological advancements requiring specialized robotic equipment for field coating.

Additionally, the limited market availability—with **only two specialized providers** (CRTS and Tyhoo)—represents a significant risk factor, potentially affecting service reliability, pricing stability, and availability of timely technical support during pipeline construction and maintenance activities.

c. Inspection and Maintenance Costs

The present study assumes inspection intervals and costs consistent with industry standards: bare pipes inspected every 3–5 years and coated pipes every 5–10 years.

These assumptions align well with existing literature (e.g., NACE SP21430-2023), which emphasizes reduced inspection frequency and lower maintenance expenditures as key benefits of internally coated pipelines.

3. Additional Considerations from Literature

Beyond direct financial comparisons, existing literature emphasizes several qualitative factors that further support the adoption of internally coated pipeline systems:

a. Technical Reliability and Durability

Research from sources such as Al-Qahtani Pipe Coating Industries underscores the superior durability of shop-applied FBE coatings compared to field-applied coatings. Our analysis confirms this finding by documenting a 2.8-fold increase in defects for field-applied coatings compared to shop-applied coatings.

Innovations like Victaulic's X07 coupling system, implemented in Chilean projects such as SQM's TEA pipeline and AMSA's INCO, offer promising alternatives that eliminate the need for field joint coating altogether. This approach not only enhances pipeline reliability and reduces dependency on highly skilled welders, but also significantly lowers overall costs and accelerates pipe joining processes.

Furthermore, the coupling mitigates project risks by minimizing dependency on favorable weather conditions—unlike welding operations, which are highly sensitive to environmental factors—thus providing greater operational flexibility and predictability during pipeline construction.

b. Altitude and Operational Conditions

Literature on high-altitude pipeline corrosion indicates increased susceptibility to localized pitting corrosion at elevations above 3,000 meters due to environmental stressors like temperature fluctuations and oxygen availability.

C. Summary Table: Literature Comparison Overview

Aspect	***This Study Findings***	***Existing Literature Findings***	***Alignment/Discrepancy Explanation***
Lifecycle Cost Savings	31.9%	NACE: 28–34%, CAPP: 22–25%	Strong alignment; minor differences due to regional factors
Energy Cost Assumption	$175/MWh	North America: $85–110/MWh	Discrepancy due to Chilean-specific energy market dynamics
Field Joint Coating Cost Ratio	6.4× steel costs	TYHOO: ~6×; IEC: ~4.8×	Alignment with recent audits; discrepancy due to inflationary pressures
Inspection Intervals & Costs	Bare: $8k/km/yr; Coated: $4k/km/yr	Industry standard intervals & similar costs	Strong alignment
Environmental Impact	Eliminates chemical inhibitors	EPA highlights ecological risks	Reinforces environmental advantage of internally coated systems
Technical Reliability	Field joints have higher defect rate	Al-Qahtani confirms superior shop coatings	Alignment; highlights need for improved field application methods
Altitude Considerations	Corrosion allowance potentially insufficient at high altitudes (>3000m)	MDPE confirms increased pitting risks at high altitudes	Alignment; underscores importance of site-specific evaluations

D. Conclusion on Literature Comparison

Overall, this expanded comparison demonstrates strong consistency between our findings and existing industry literature while highlighting specific regional factors—particularly energy pricing—that influence lifecycle cost outcomes significantly.

The observed discrepancies are well-explained by contextual differences (such as geographic location and market conditions), reinforcing confidence in our results while emphasizing the importance of adapting corrosion mitigation strategies to local operational contexts.

APPENDIX A

Table 9. Bare pipe Electricity cost calculations.

Analyzed case: Bare. Initial wall thickness = 13.28 mm; year 25 wall thickness = 9.53 mm. Initial pipe roughness = 0.025 mm; year 25 pipe roughness = 0.3 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	0.025	684.640	13.28000	1.901	0.012356	332.69	2869	8623	$4,216,922	$12,675,334
2	0.036	684.953	13.12375	1.900	0.012662	340.15	2933	8623	$4,311,473	$12,675,334
3	0.048	685.265	12.96750	1.898	0.012945	346.95	2992	8623	$4,397,736	$12,675,334
4	0.059	685.578	12.81125	1.896	0.013208	353.21	3046	8623	$4,477,040	$12,675,334
5	0.071	685.890	12.65500	1.895	0.013455	359.00	3096	8623	$4,550,407	$12,675,334
6	0.082	686.203	12.49875	1.893	0.013688	364.38	3142	8623	$4,618,642	$12,675,334
7	0.094	686.515	12.34250	1.891	0.013909	369.41	3185	8623	$4,682,391	$12,675,334
8	0.105	686.828	12.18625	1.889	0.014119	374.13	3226	8623	$4,742,177	$12,675,334
9	0.117	687.140	12.03000	1.888	0.014319	378.56	3264	8623	$4,798,437	$12,675,334
10	0.128	687.453	11.87375	1.886	0.014510	382.75	3300	8623	$4,851,533	$12,675,334
11	0.140	687.765	11.71750	1.884	0.014694	386.72	3335	8623	$4,901,772	$12,675,334
12	0.151	688.078	11.56125	1.882	0.014870	390.48	3367	8623	$4,949,417	$12,675,334
13	0.163	688.390	11.40500	1.881	0.015040	394.05	3398	8623	$4,994,694	$12,675,334
14	0.174	688.703	11.24875	1.879	0.015205	397.45	3427	8623	$5,037,798	$12,675,334
15	0.185	689.015	11.09250	1.877	0.015363	400.69	3455	8623	$5,078,901	$12,675,334
16	0.197	689.328	10.93625	1.876	0.015517	403.79	3482	8623	$5,118,153	$12,675,334
17	0.208	689.640	10.78000	1.874	0.015667	406.75	3507	8623	$5,155,689	$12,675,334
18	0.220	689.953	10.62375	1.872	0.015812	409.58	3532	8623	$5,191,627	$12,675,334
19	0.231	690.265	10.46750	1.871	0.015953	412.30	3555	8623	$5,226,072	$12,675,334
20	0.243	690.578	10.31125	1.869	0.016090	414.91	3578	8623	$5,259,120	$12,675,334
21	0.254	690.890	10.15500	1.867	0.016224	417.41	3599	8623	$5,290,857	$12,675,334
22	0.266	691.203	9.99875	1.866	0.016354	419.82	3620	8623	$5,321,361	$12,675,334
23	0.277	691.515	9.84250	1.864	0.016481	422.13	3640	8623	$5,350,702	$12,675,334
24	0.289	691.828	9.68625	1.862	0.016606	424.36	3659	8623	$5,378,945	$12,675,334
25	0.300	692.140	9.53000	1.860	0.016728	426.51	3678	8623	$5,406,148	$12,675,334
					Bare Pipe Case. Present Value (annual OPEX discounted at 10% rate)				$42,711,319	$115,054,517

Table 10. Coated pipe Electricity cost calculations

Analyzed case: Coated. Initial wall thickness = 9.53 mm; year 25 wall thickness = 9.53 mm. Initial pipe roughness = 0.015 mm; year 25 pipe roughness = 0.04 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	0.0150	692.140	9.53000	1.860	0.012080	308.02	2656	8623	$3,904,265	$12,675,334
2	0.0158	692.140	9.53000	1.860	0.012105	308.65	2661	8623	$3,912,223	$12,675,334
3	0.0167	692.140	9.53000	1.860	0.012130	309.27	2667	8623	$3,920,127	$12,675,334
4	0.0175	692.140	9.53000	1.860	0.012154	309.89	2672	8623	$3,927,977	$12,675,334
5	0.0183	692.140	9.53000	1.860	0.012178	310.51	2677	8623	$3,935,775	$12,675,334
6	0.0192	692.140	9.53000	1.860	0.012202	311.12	2683	8623	$3,943,522	$12,675,334
7	0.0200	692.140	9.53000	1.860	0.012226	311.72	2688	8623	$3,951,218	$12,675,334
8	0.0208	692.140	9.53000	1.860	0.012249	312.33	2693	8623	$3,958,863	$12,675,334
9	0.0217	692.140	9.53000	1.860	0.012273	312.93	2698	8623	$3,966,460	$12,675,334
10	0.0225	692.140	9.53000	1.860	0.012296	313.52	2703	8623	$3,974,008	$12,675,334
11	0.0233	692.140	9.53000	1.860	0.012319	314.11	2709	8623	$3,981,508	$12,675,334
12	0.0242	692.140	9.53000	1.860	0.012343	314.70	2714	8623	$3,988,961	$12,675,334
13	0.0250	692.140	9.53000	1.860	0.012365	315.29	2719	8623	$3,996,367	$12,675,334
14	0.0258	692.140	9.53000	1.860	0.012388	315.87	2724	8623	$4,003,728	$12,675,334
15	0.0267	692.140	9.53000	1.860	0.012411	316.44	2729	8623	$4,011,044	$12,675,334
16	0.0275	692.140	9.53000	1.860	0.012433	317.02	2734	8623	$4,018,315	$12,675,334
17	0.0283	692.140	9.53000	1.860	0.012456	317.59	2738	8623	$4,025,543	$12,675,334
18	0.0292	692.140	9.53000	1.860	0.012478	318.16	2743	8623	$4,032,727	$12,675,334
19	0.0300	692.140	9.53000	1.860	0.012500	318.72	2748	8623	$4,039,869	$12,675,334
20	0.0308	692.140	9.53000	1.860	0.012522	319.28	2753	8623	$4,046,969	$12,675,334
21	0.0317	692.140	9.53000	1.860	0.012544	319.84	2758	8623	$4,054,028	$12,675,334
22	0.0325	692.140	9.53000	1.860	0.012566	320.39	2763	8623	$4,061,045	$12,675,334
23	0.0333	692.140	9.53000	1.860	0.012587	320.94	2767	8623	$4,068,023	$12,675,334
24	0.0342	692.140	9.53000	1.860	0.012609	321.49	2772	8623	$4,074,961	$12,675,334
25	0.0350	692.140	9.53000	1.860	0.012630	322.03	2777	8623	$4,081,860	$12,675,334
				Bare Pipe Case. Present Value (annual OPEX discounted at 10% rate)					$35,957,717	$115,054,517

TABLE 11. 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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