

Analysis of Corrosion in Pipelines Using Computational Fluid Dynamics and Corrosion Rate Prediction Models

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Abstract - This study delves into the comprehensive analysis of the impact of various parameters on CO₂ corrosion within the oil and gas industry. The primary focus is directed towards understanding the influence of temperature, pH value, CO₂ partial pressure, supersaturation and the development of corrosion product films on the corrosion rate. The simulation of a two-phase water-CO₂ fluid flow was executed in a horizontal pipe characterized by a length (l) of 5000 mm and a diameter (d) of 127 mm, utilizing the OpenFoam software package. To predict the corrosion rate, a Norsok M – 506 prediction model, implemented in the Python programming language, was employed. Mesh generation was performed by the Salome software package, and post-processing procedures were executed using the Paraview software package. To ensure that the analyzed results were independent of the mesh, a mesh refinement study was conducted using five systematically refined meshes. The simulation results were subsequently utilized as input parameters for the developed Norsok M – 506 prediction model, and the model's accuracy was validated against measurement data. The analysis showed that temperature had the greatest impact on the corrosion rate in the pipeline. Operating temperatures within the range of 100 – 50 °C were identified as conducive to the formation of a protective film, effectively decelerating the corrosion rate. In contrast, other parameters such as pH value, CO₂ partial pressure, and fluid flow rate exhibited a comparatively diminished impact on the corrosion rate under the specified conditions. Consequently, the determined annual corrosion rate amounted to 0.5 ± 0.2 mm per year.

Keywords: corrosion, corrosion models, two phase flow, Python, CFD.

1. Introduction

Corrosion is a complex electrochemical process that occurs due to the interaction of materials, typically metals, with the surrounding environment. This reaction results in the gradual erosion and degradation of the material, leading to the deterioration of its physical and mechanical properties [1]. This study focuses on the analysis of CO₂ or "sweet corrosion", a chemical corrosion which occurs as a result of complex electrochemical reactions between metals and carbonic acid (H₂CO₃). This acid has the ability to induce rapid and comprehensive corrosion of metals, as well as severe localized corrosion damage on metal surfaces. Research conducted in both domestic and foreign studies unequivocally indicates that up to 70% of corrosion in oil and gas gathering and transportation systems can be attributed to the action of CO₂, while the remaining 30% is primarily associated with the activity of sulfate-reducing bacteria [2]. Without adequate maintenance, every pipeline system will inevitably experience corrosion over time, resulting in worsened pipe integrity and an increased risk of failures. Pipeline failures have serious consequences, including plant and platform shutdowns [2, 3]. CO₂ corrosion requires a comprehensive approach that involves an understanding of solution chemistry, metallurgy, electrochemistry, hydrodynamics, inhibitors, and other relevant disciplines [4]. The key factors causing CO₂ corrosion can be categorized into environmental, physical and metallurgical parameters. Many authors consider the following parameters to be the most influential: pH, temperature, CO₂ partial pressure, flow rate, supersaturation, formation of corrosion product films and presence of H₂S [5, 6, 7]. In the context of this research, an integrated approach has been applied, combining an empirical model for predicting the rate of CO₂ corrosion in a horizontal pipeline, developed according to the Norsok M - 506 Norwegian standard, with computational fluid dynamics (CFD) simulations conducted using the OpenFoam software. The empirical corrosion prediction model is based on laboratory data previously used to calibrate the De Waard model and industry practice in the oil and gas sector, providing valuable guidance for assessing the CO₂ - induced corrosion rate [8, 9, 10].

2. Mathematical Model and Numerical Method

The mathematical model can be summarized in the following governing and constitutive equations:

Continuity equation

$$\frac{d}{dt} \int_V \rho dV + \int_S \rho(\mathbf{v} - \mathbf{v}_s) \cdot d\mathbf{s} = 0 \quad (1)$$

where ρ is density, \mathbf{v} is velocity vector and \mathbf{v}_s the velocity of the surface S .

Momentum equation

$$\frac{d}{dt} \int_V \rho \mathbf{v} dV + \int_S \rho(\mathbf{v} - \mathbf{v}_s) \cdot d\mathbf{s} = \int_S \mathbf{T} \cdot d\mathbf{s} + \int_V \mathbf{f}_b dV \quad (2)$$

where ρ is density, \mathbf{v} is velocity vector, \mathbf{v}_s the velocity of the surface S , \mathbf{T} the Cauchy stress tensor and \mathbf{f}_b is the resultant body force.

Energy equation

$$\frac{d}{dt} \int_V \rho c_v T dV + \int_S \rho c_v T(\mathbf{v} - \mathbf{v}_s) \cdot d\mathbf{s} = \int_S \mathbf{q} \cdot d\mathbf{s} + \int_V (\mathbf{T} : \text{grad} \mathbf{v}) dV \quad (3)$$

where ρ is density, c_v is specific heat at constant volume, \mathbf{v} is velocity vector, \mathbf{v}_s the velocity of the surface S , \mathbf{T} the Cauchy stress tensor, T [K] is temperature and \mathbf{q} is heat flux vector.

Transport equation of phase volume fraction

$$\frac{d}{dt} \int_V \alpha dV + \int_S \alpha(\mathbf{v} - \mathbf{v}_s) \cdot d\mathbf{s} = 0 \quad (4)$$

where \mathbf{v} is velocity vector, \mathbf{v}_s the velocity of the surface S and α is volume fraction of phase.

Equation of state

$$\rho = \rho(p, T) \quad (5)$$

where p [Pa] is the pressure of the fluid and T [K] is temperature.

Stoke's law

$$\mathbf{T} = 2\mu \mathbf{D} - \frac{2}{3} \mu \text{div} \mathbf{v} \mathbf{I} - p \mathbf{I} \quad (6)$$

where

$$\mathbf{D} = \frac{1}{2} [\text{grad} \mathbf{v} + (\text{grad} \mathbf{v})^T] \quad (7)$$

is rate of strain tensor, \mathbf{v} is velocity vector, μ is the dynamic viscosity, p is the pressure, \mathbf{T} the Cauchy stress tensor and \mathbf{I} is the unit tensor .

In this paper, the OpenFOAM solver compressibleInterFoam was utilized as a tool for simulating two compressible, non-isothermal, and immiscible fluids using the finite volume method. The turbulence model was standard k- ϵ model. The methodology follows closely the one presented in [11].

3. Numerical Modelling of Two-Phase Water-CO₂ Flow Through the Horizontal Pipe

The two-phase flow of water-CO₂ through horizontal pipe was analyzed. The geometry and the numerical mesh of the pipe was given in the Figure 1, while the geometry of the pipe was given in the Figure 2.

The results of numerical simulations were analyzed for five different meshes with cell base sizes of 0.075, 0.05, 0.025, 0.0125, and 0.012, and five different time steps: 1, 2, 3, 4, 5, respectively. The objective of this analysis is to determine how different cell sizes and time steps affect the results and stability of the numerical simulation, aiming to select the optimal case for the corrosion analysis in a horizontal pipe.

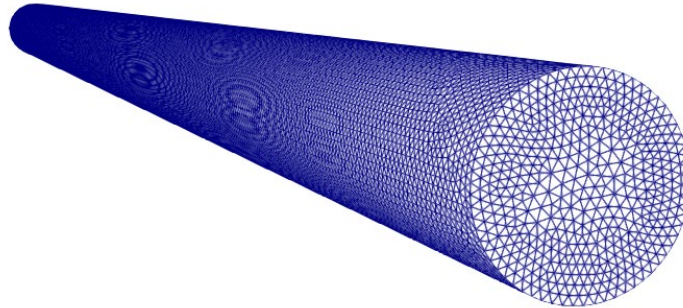


Fig. 1: Numerical mesh of the pipe

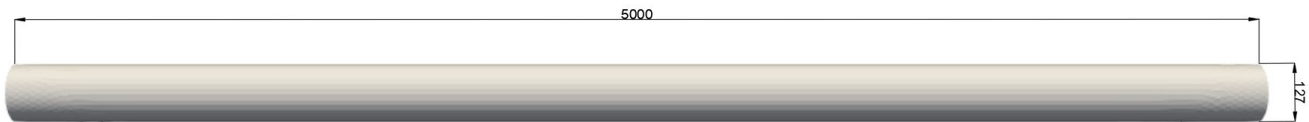


Fig. 2: Geometry

When it comes to processing time (CPU time), for mesh 1, the compressibleInterFoam solver requires 0.070 hours for 10 seconds of simulation, while for mesh 2 it is 0.072 hours. Regarding mesh 3, the CPU time amounts to 1.375 hours for ten seconds of simulation, while for mesh 4 the CPU time is 39.33 hours. Finally, the CPU time for mesh 5 is 64.50 hours, as shown in Table 1.

Table 1: Comparison of processing time (CPU) for different mesh sizes

Mesh	Cell base size	Number of cells	CPU [hours]
1	0.075	3023	0.070
2	0.05	7334	0.072
3	0.025	51076	1.375
4	0.0125	414133	39.33
5	0.012	420766	64.50

Figure 3 shows the cross-section of the pipe used to simulate two-phase fluid flow at different mesh resolutions. It is observed that refining the mesh systematically achieves better accuracy in simulation results (Figure 4) but, on the other hand, significantly prolongs the simulation execution time. Based on Table 1, Figure 3 and Figure 4, it is noticed that meshes 1 and 2 have low spatial resolution, with almost 17 times fewer cells compared to mesh 3, but their results are not as accurate and precise as those for meshes 3, 4, and 5. Mesh 3 provides results that minimally differ from the results obtained by meshes

4 and 5. From the above, it can be concluded that reducing the size of the base cell does not significantly improve result accuracy and requires even 28.6 times (mesh 3) and 49.9 times (mesh 4) more execution time.

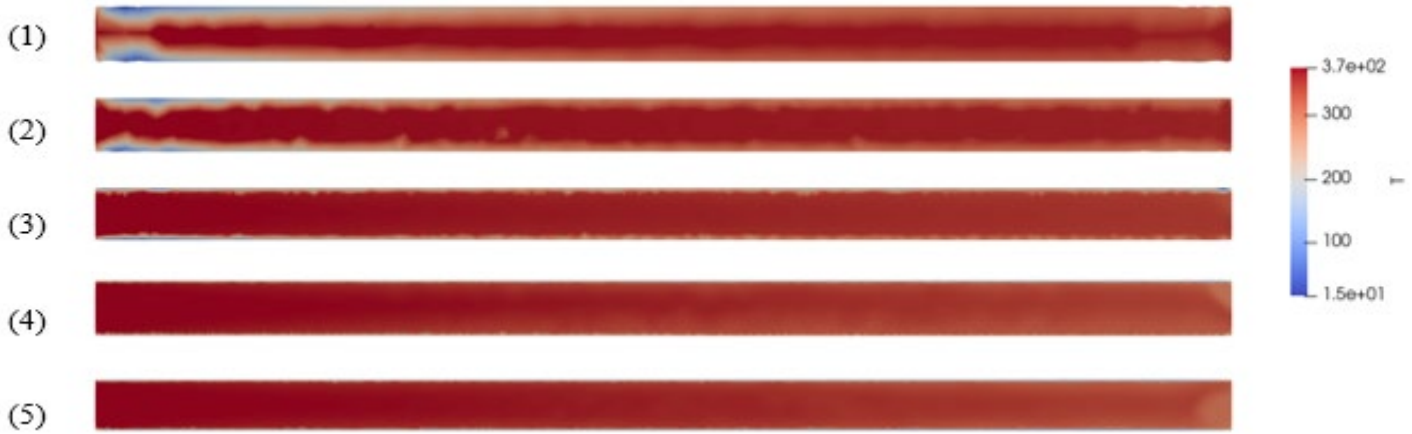


Fig. 3: Temperature (T) at the cross-section of the pipe, D = 127 mm, L = 5000 mm, for mesh cell sizes: (1) 0.075, (2) 0.05, (3) 0.025, (4) 0.0125, (5) 0.0120

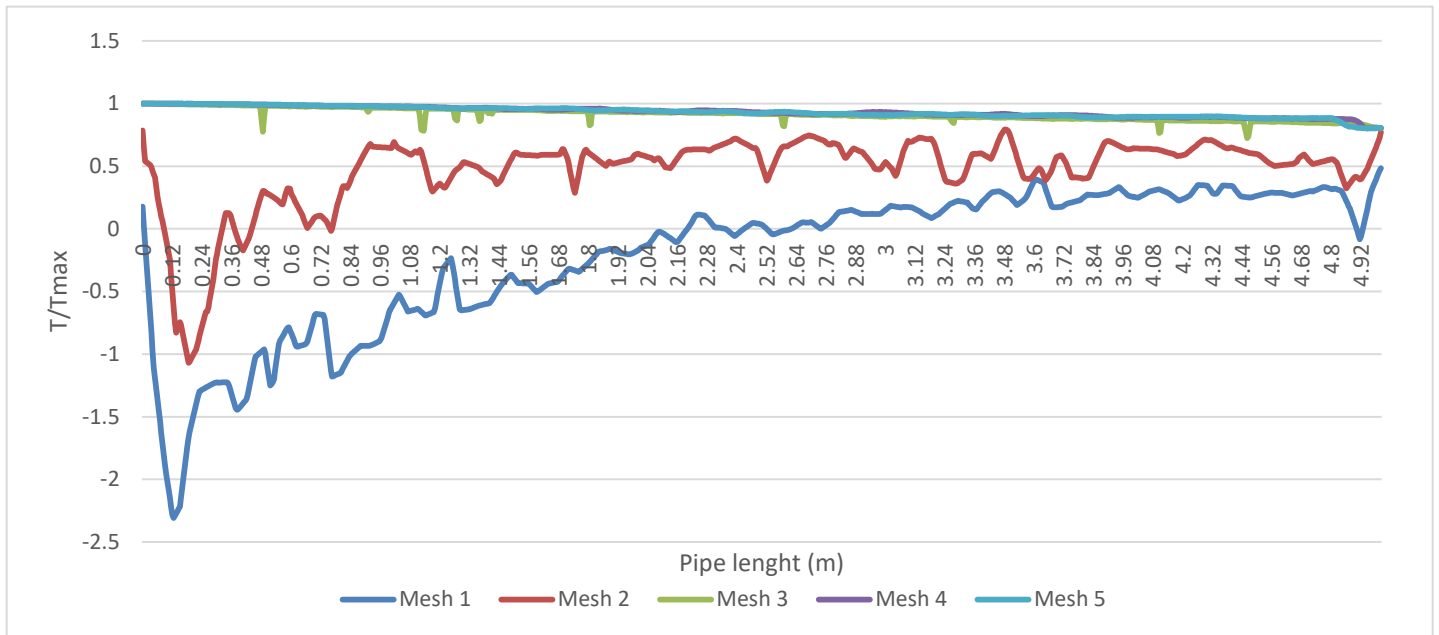


Fig. 4: Graphical representation of temperature (T) simulation results for mesh 1, 2, 3, 4, and 5

Considering corrosion as a highly intricate phenomenon, the aim is to obtain more accurate results for the most significant parameters. Therefore, a mesh 4 is chosen that delivers precise results, even at the expense of significantly longer simulation execution time.

4. Results and Discussion

When utilizing the NORSOK M-506 model for predicting the corrosion rate induced by CO_2 , there is an implicit assumption. It should be noted that the corrosion rate predicted by this model is valid only where the metal has actually been moistened [4]. In this sense, it is important to be aware that the corrosion map obtained from this corrosion model must be interpreted in accordance with the distribution of the aqueous phase.



Fig. 5: Distribution of the aqueous phase on the pipe walls

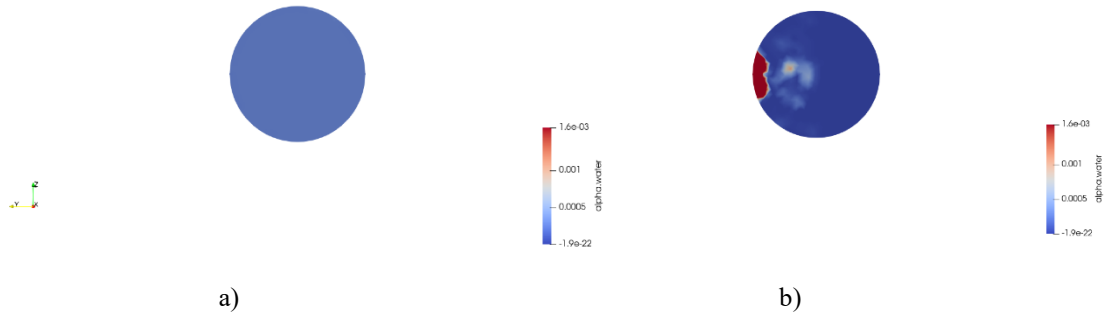


Fig. 6: Distribution of the aqueous phase a) at the pipe inlet, b) at the pipe outlet

According to Figures 5 and 6, it can be concluded that almost the entire surface of the pipe is wetted by the aqueous phase and is therefore very susceptible to corrosion. The conclusion is that corrosion will be more pronounced at the inlet than at the outlet of the pipe, because the pipe is completely wet at the inlet.

Various studies have been conducted, determining that the corrosion rate increases with rising temperature and peaks in the range of 60 to 80 °C. This temperature range also provides optimal conditions for forming a protective film. With further temperature increase, the amount of protective film will decrease, subsequently increasing the corrosion rate [12].

The formation of an iron carbonate layer requires water saturation with iron carbonate, i.e., a pH value above 5.5, a temperature above 60 °C, and low to moderate fluid velocity which is explained in [13].

In this case, the pH value is set at 5.6, the fluid flow rate at the pipe inlet is 1.5 m/s, and the temperature is set at 100 °C. Over time, due to cooling, it reached the ideal temperature range for forming an iron carbonate protective film, as shown in Figure 7.

According to API 14E, the critical velocity of two-phase flow is calculated to be approximately 3.9 m/s [4]. Simulation results of the flow indicate that the average fluid velocity in the examined pipe is not higher than the calculated critical velocity. Therefore, it can be concluded that the pipe is not exposed to corrosion at locations where the fluid flow changes.

The cross-section of the pipe was made 0.06 m away from the center of the pipe to clearly visualize the temperature profile near the pipe wall, as temperatures on the walls are relevant for corrosion analysis. Figure 7 presents a graphical

representation of the temperature change along the pipe. As assumed, the temperature in the pipe section from 0.8 to 3.64 m fulfills ideal conditions for the formation of a protective film. This confirms the assumption that the protective film will form, slowing down the corrosion process.

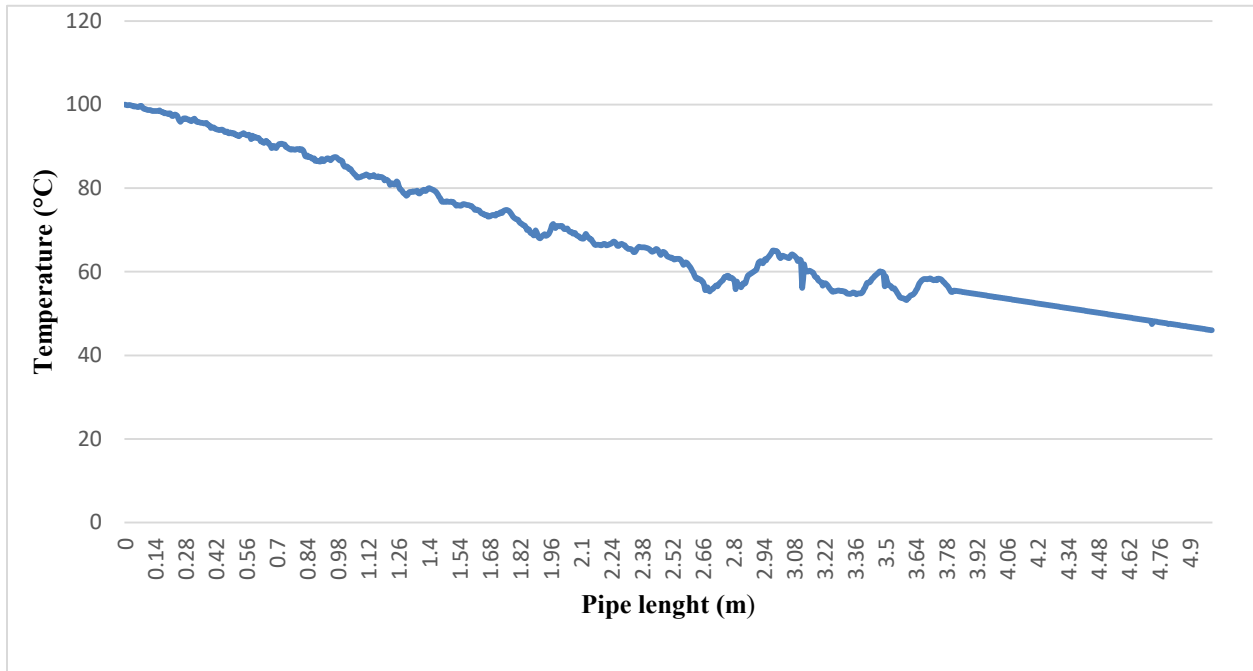


Fig. 7: The temperature change along the pipe in close proximity to the pipe wall

In the analyzed case, the CO₂ partial pressure of 0.004 bar is relatively low and will not cause a high concentration of dissolved CO₂ in water. This means that, although CO₂ partial pressure can contribute to corrosion, the impact will be limited.

Considering all the factors mentioned, the assumption is that corrosion will be slowed down, and a protective film will form, especially in the part of the pipe where the temperature falls within the ideal range.

Figure 8 presents a graphical representation of the predicted corrosion rate (mm/year) along the length of the pipe. It can be observed that the estimated corrosion rate is 0.5 ± 0.2 mm/year.

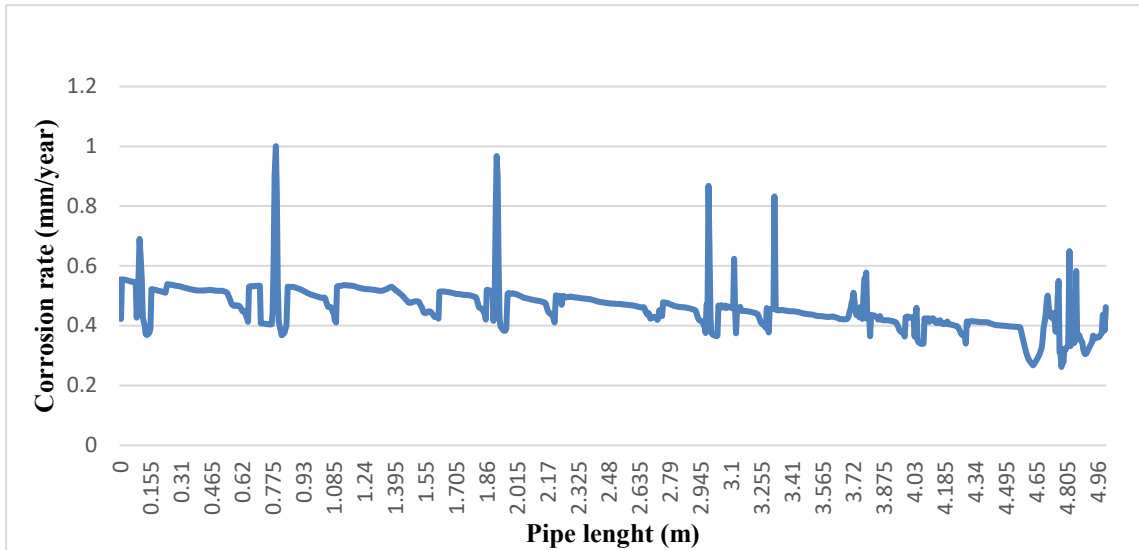


Fig. 8: Prediction of corrosion rate along the pipe using NORSOK 506-model

5. Conclusion

Simulation results provide profound insights into the corrosion process. Analyzing a range of factors, it can be concluded that a low CO₂ partial pressure results in a limited concentration of dissolved CO₂ in water, reducing the impact of CO₂ on corrosion. Fluid flow velocity also plays an important role. Research results indicate that fluid flow velocity in the pipe remains below the critical velocity, thereby protecting the pipe from corrosion where fluid flow changes. The simulation suggests that at specific locations within the pipe, ideal conditions for forming a protective film of iron carbonate will further reduce the corrosion process.

The estimated corrosion rate based on simulation is 0.5 ± 0.2 mm/year, providing optimistic results for preserving system integrity.

This study contributes to a better understanding of corrosion risk in complex industrial facilities. Continuous monitoring and management of corrosion risk are crucial for the safety and reliability of infrastructure in the oil and gas industry.

Through fundamental model verification and reliability analysis, this study provides engineers and operators with valuable tools for managing corrosion risk and extending the operational life of equipment.

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