



Technical Paper

MANAGING OXYGEN CORROSION RISK IN NATURAL GAS PIPELINES USING ZERO₂ TECHNOLOGY

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INTRODUCTION

The integrity of natural gas pipelines is a critical factor in the reliability and safety of gas gathering systems and midstream transmission infrastructure. Even minor disruptions can create substantial operational, safety, and financial consequences.

One contaminant posing a risk to pipeline integrity that is sometimes underestimated in terms of its risk profile is oxygen. Most operators of natural gas pipelines impose strict oxygen limits because the presence of oxygen inside pressurized steel pipeline creates a highly corrosive environment, especially when moisture is present. Despite the best precautions; leaks, poor handling practices, and operational upsets can allow oxygen to enter pipelines, tanks, and other facility equipment. Once present, oxygen can accelerate corrosion, increase the likelihood of leaks or ruptures, create fire and/or explosion hazards and increase the replacement frequency of pipeline components.

The risks of oxygen contamination are not theoretical. The Carlsbad, New Mexico, pipeline rupture on August 19, 2000, resulted in multiple fatalities and highlighted the consequences of internal corrosion and inadequate gas quality management ([Pipeline Accident Report NTSB/PAR-03/01](#)).

The Abstract reads:

At 5:26 a.m., mountain daylight time, on Saturday, August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, New Mexico. The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged. According to El Paso Natural Gas Company, property and other damages or losses totaled \$998,296.

Additional accident investigations and failure reports catalogued by Pipeline and Hazardous Materials Safety Administration (PHMSA) underscore the broader industry concern ([PHMSA Pipeline Failure Investigation Reports](#)). Since then, the industry's safety performance has improved considerably. As of the most recently available data (October 25, 2024), PHMSA records show 114 pipeline failures between November 3, 2003 and February 12, 2023. Of these incidents, 24, or roughly 21%, were attributed to internal or external corrosion, with the most recent corrosion-related failure occurring on August 3, 2015 (Tennessee Gas Pipeline Company).

Objective: This paper examines the mechanisms of corrosion in natural gas pipelines, with a focus on oxygen-driven corrosion. We explore why most pipeline operators impose strict oxygen specifications, review common mitigation approaches, and introduce the **ZerO2® system from EcoVapor**, a proven catalytic technology solution for variable oxygen removal that enables operators to maintain compliance and protect pipeline integrity.

II. Technical Background: Oxygen Corrosion in Natural Gas Pipelines

Why Do Steel Pipes Corrode?

Steel remains the material of choice for natural gas pipelines, in both gathering systems and transmission lines, because it delivers the strength and durability needed to manage high pressures, temperatures, and throughput, all at an affordable cost – the same reasons that make steel an ideal choice for applications in other industries.

When steel is produced, mined materials (i.e., iron oxide, rust, and hematite) are heated to high temperatures to remove the impurities. Then, different alloying elements, typically carbon (C), copper (Cu), manganese (Mn), silicon (Si), and others, can be introduced in controlled amounts to give steel specific, desirable material properties. These treatments enhance strength, hardness, ductility, weldability, and other performance characteristics, each with inherent trade-offs that must be balanced for the intended application.

Corrosion occurs because the process of making steel alters the iron ore by adding energy to the system, driving the material away from its natural, stable state. As with any energized system, steel naturally tends to revert to equilibrium, which for iron ore means oxidizing back towards its natural ore form. Iron's abundance and high reactivity, when combined with common oilfield contaminants such as oxygen, H₂S, and CO₂, to name a few – make this process especially pronounced in oil and gas production. For the purposes of this paper, where the primary focus is on oxygen corrosion, we will assume all pipelines are “dry.”

The conceptual illustration seen here (Figure 1) shows how energy is added in the steel manufacturing process, and the forces providing a pathway for energy to leave the system (e.g., corrosion converting steel back to iron oxide or rust).

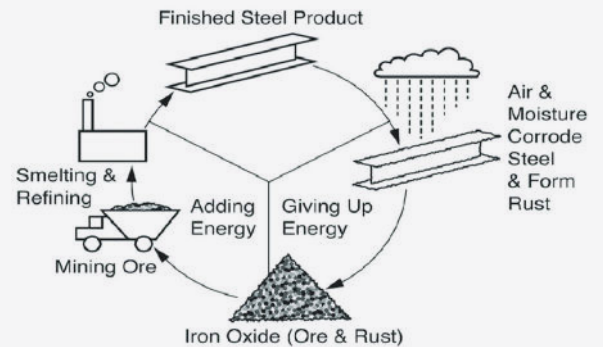


Figure 1: **The Steel Lifecycle: From Nature to Rust**

Factors Driving Corrosion

Corrosion in steel pipelines and metallic systems in general arises from a combination of environmental, mechanical (operational), and chemical influences. Understanding these factors is essential for predicting corrosion behavior and implementing effective mitigation strategies. Key contributors include **temperature, fluid velocity, pressure, changes in pipeline direction or elevation**, the **chemical composition of the electrolyte**, and the presence of **dissolved gases**.

Environmental and Operational Factors

Temperature is a primary driver of corrosion because it introduces energy into the system, accelerating chemical reactions. In practice, the corrosion rate approximately doubles with every 10°C (18°F) increase in temperature. Protective scales that naturally form on metal surfaces can moderate this effect, slowing corrosion progression. However, the rate and extent of scale formation are not uniform; higher temperatures may enhance some protective layers while inhibiting others, depending on the metal and fluid chemistry. For example, in carbon steel pipelines, elevated temperatures can promote the formation of iron carbonate scales in CO₂-rich fluids, which can act as a temporary barrier to corrosion.

Fluid velocity influences how corrosion manifests. High velocities increase the risk of erosion-corrosion, where flowing fluid mechanically removes protective films and scales. Conversely, low velocities can produce stratified or slug flow conditions, which create localized corrosion hotspots from stagnant pockets of fluid. Engineers often observe these effects at pipeline bends or in sections with reduced diameter, where flow disturbances are common.

1. ([Y Sahan et al 2018](#) IOP Conf. Ser.: Mater. Sci. Eng. 345 012038)

Pressure affects scale formation, fluid shear and molecule concentration. Elevated pressures can facilitate the development of protective scales, whereas low-pressure zones can increase shear stress, promoting erosion. For instance, pressure drops at pipeline elevation changes or across control valves can locally accelerate material loss.

Partial Pressure affects the amount of actual corrodent molecules contacting any given surface area of pipe, because the higher the pressure the greater the potential energy contained in the pipe. As shown below, the same concentration at different pressures equals radically different rates of contact between the corrodent and the worked metal.

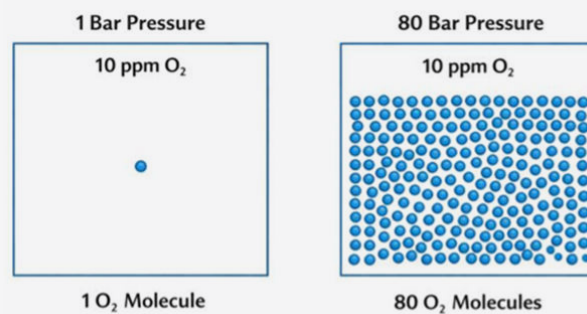


Figure 2: **Cumulative Partial Pressure Behavior**

Changes in direction or elevation in a pipeline system further contribute to corrosion risk. These features provide surfaces where water or other liquids can accumulate, forming localized wet spots. In addition, pressure drops associated with elevation changes can reduce fluid temperature, increasing the likelihood of condensation and creating microenvironments conducive to corrosion.

Fluid Composition

The **electrolyte composition**, the fluid in contact with the metal, plays a critical role in determining corrosion rates. The metallurgy of the steel interacts with dissolved ions in ways governed by solubility and chemical reactivity. Total dissolved solids (TDS), including salts and other ions, can directly participate in corrosion reactions or act as nutrients for microbes that induce microbiologically influenced corrosion (MIC).

Fluid pH also influences corrosion by promoting or inhibiting scale formation based on the metal's chemical properties. Suspended solids can abrade protective films or create localized anodic sites, further complicating corrosion behavior.

Dissolved Gases

Finally, **dissolved gases** such as carbon dioxide (CO₂), hydrogen sulfide (H₂S), and oxygen (O₂) are critical accelerants of corrosion. Under pressure, CO₂ can lead to the formation of carbonic acid, increasing general corrosion rates, while H₂S promotes sulfide stress cracking in susceptible alloys. Oxygen accelerates oxidation reactions, often in combination with other factors. Each of these gases interacts with temperature, pressure, flow conditions, and metallurgy in complex ways that are discussed in detail in subsequent sections.

Additionally, at higher pressures (with all other factors being equal), more gas molecules are forced into a liquid, as each gas has a higher partial pressure. A soda can is a great example of this concept, as once you open the can, the can immediately equalizes at low pressure, which creates the “fizz” from dissolved CO₂ escaping from the liquid.

By considering these factors holistically, engineers can better predict where and how corrosion will

Table 1: **Summary of Corrosion Factors**

Factor	Effect on Corrosion	Illustrative Example / Notes
Temperature	Increases reaction rates; roughly doubles corrosion for every 10°C (18°F) rise	Can promote or inhibit scale formation, e.g., iron carbonate scales in CO ₂ -rich fluids
Fluid Velocity	High velocity erosion-corrosion; Low velocity → stratified or slug flow	Bends or diameter reductions are prone to erosion or localized corrosion
Pressure	High pressure can enhance scale formation; low pressure can increase shear and erosion	Pressure drops across valves or elevation changes can accelerate localized corrosion
Partial Pressure	High partial pressure of corrodents greatly increases the number of times those molecules strike the surface and increase corrosion rate	A can of soda immediately releases gas that is dissolved in the liquid when opened due to the partial pressure. Additionally, it requires a protective internal coating to prevent corrosion and metal leaching (dissolution) into the beverage in question
Direction / Elevation Changes	Accumulation surfaces for water; pressure drops can cause condensation	Pipeline bends, rises, and drops often create wet spots and localized corrosion zones
Metallurgy / Electrolyte Composition	Determines reaction susceptibility; interacts with dissolved ions	Alloy choice influences scale formation, resistance to MIC, and chemical attack
Total Dissolved Solids (TDS)	Salts and ions can react with steel or feed microbial growth	High TDS can accelerate general corrosion or MIC
pH	Promotes or inhibits scale formation depending on metal chemistry. Promotes microbial growth within certain ranges	Acidic fluids accelerate general corrosion; alkaline conditions may protect certain metals, pH can heavily influence what microbes are nurtured vs killed
Suspended Solids	Abrade protective films; create localized anodic sites	Sand or silt in flow can strip scales and expose fresh metal
Dissolved Gases (CO₂, H₂S, O₂)	Each gas accelerates corrosion through distinct chemical/electrochemical mechanisms	CO ₂ → carbonic acid; H ₂ S → sulfide stress cracking; O ₂ → oxidation

Measuring Corrosion

In addition to learning the factors driving corrosion, it is important to have a method for quantifying it, since corrosion is an ongoing and inevitable process.

One of the simplest forms to measure is uniform (or general) corrosion, which represents the consistent loss of metal over time (typically one year). The National Association of Corrosion Engineers (NACE) established a standard unit for expressing the corrosion rate, where 1 mil = 0.001 inches, and rates are typically reported as mils per year (mpy).

The table below summarizes the primary categories of corrosion by rate and performance.

Table 2: **Corrosion Categories**

Category	Corrosion Rate	Performance
I	< 0.15 mm/year (0.005 mpy or 5.9 mil)	Good corrosion resistance to the extent that they are suitable for critical parts (e.g., valve seats, pump shafts, and impellers)
II	0.15 – 1.5 mm/year (0.005-0.05 mpy or 5.9-59 mil)	Satisfactory performance, if a higher rate of corrosion can be tolerated (e.g., tanks, piping, valve bodies, and bolt heads).
III	> 1.5 mm/year (>0.05 mpy or >59 mil)	Usually not satisfactory.

(Hanan Ahmed Alnakra, 2023)

Corrosion Mechanisms

Now that we know why corrosion exists in steel pipelines and how to measure it, let's turn our attention to how corrosion happens and what major mechanisms cause it. This list is intentionally focused strictly on oxygen-related mechanisms.

Galvanic Cell Corrosion

A galvanic cell is the most fundamental corrosion mechanism, and all other corrosion methods where the mechanism is known, involve some modification of the galvanic cell. This is an inherent and systemic corrosion mechanism because to make steel we have added energy to the system and that system will always want to return to its natural state.

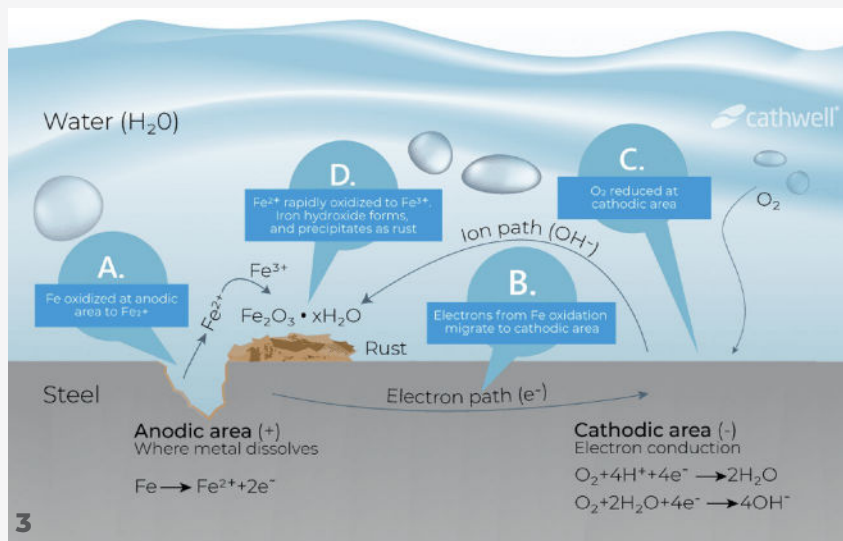
As **Le Chatelier** proved, any chemical system will achieve equilibrium over time, and the surrounding environment will force a worked metal, such as steel, back into its natural state (i.e. iron ore/rust). From this perspective, oxygen is an inherent hazard for steel pipelines. Lastly, even trace amounts of water still have an impact on most corrosion mechanisms.

Four components are required to form a Galvanic corrosion cell:

1. **Anode:** The “sacrificial” metal that corrodes, donating electrons in the process
2. **Cathode:** The metal surface that remains largely corrosion-free, accepting electrons
3. **Electrical conductor:** The pathway (typically a metal wire between the anode and cathode) allowing the electron flow
4. **Electrolyte:** An aqueous solution that enables ion movement between the anode and cathode, completing the circuit

In the corrosion process detailed below, iron metal becomes the Anode, and elemental oxygen is reduced to water at the cathode. The soluble Fe^{2+} acts as an electrolyte which provides a path to reduce to Fe^{3+} (insoluble, which makes rust) but this process generates water. This is significant in that it shows how oxygen attacks steel to finish the galvanic corrosion cell in a dry gas application.

Figure 3: **Galvanic Cell Corrosion Mechanism**



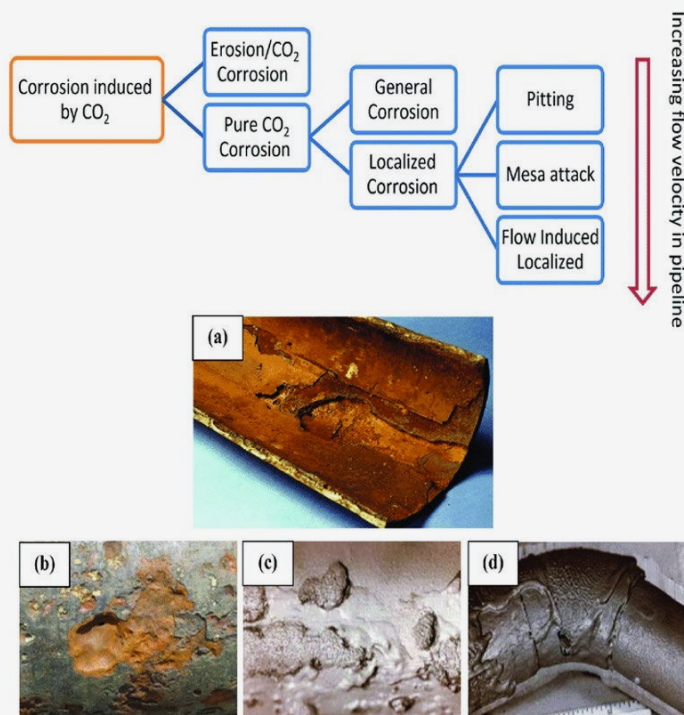
CO₂ Corrosion

The presence of CO₂ significantly increases the general corrosion rate. While the exact mechanism is still debated, CO₂ corrosion is commonly associated with **pitting corrosion**, which typically forms round-bottomed, steep-walled pits with sharp edges. Even trace amounts of water in dry natural gas pipelines can lead to substantial CO₂ corrosion, so it warrants detailed discussion.

- At **low flow velocities**, pits often interconnect, forming elongated patterns.
- At **high flow velocities**, pits usually initiate at points of flow disturbance.

Figure 4 below illustrates how velocity impacts CO₂ corrosion specifically. The slower the velocity, the more localized the corrosion is, but the faster the velocity, the more “area of effect” the corrosion becomes. Pictogram A shows “pure” CO₂ corrosion, Pictogram B shows more localized CO₂ corrosion. Pictogram C shows pitting corrosion; you can tell this is a medium-flow scenario as the pits connect to one another. Pictogram D shows what happens when the protective Iron Carbonate is totally stripped away via high velocity and the corrosion mechanism spreads due to a high partial pressure of CO₂ and low pH.

Figure 4: **Erosional Velocity Impacts on CO₂ Corrosion**



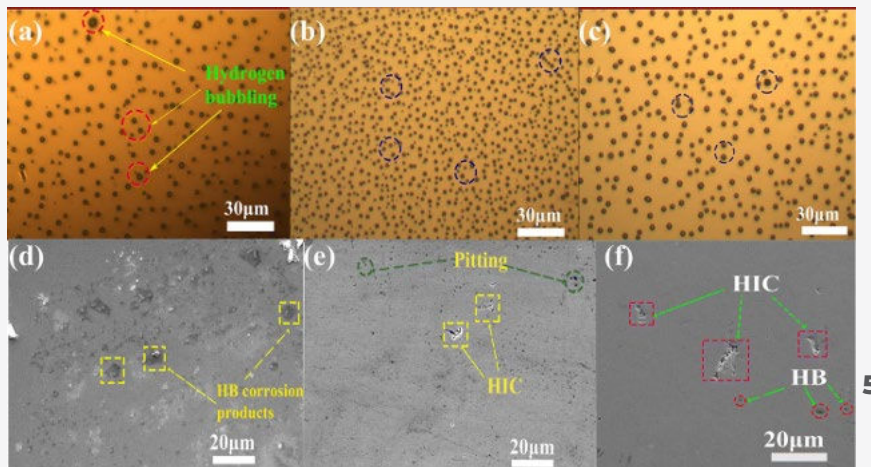
4. ([Mariano Iannuzzi - About Corrosion](#))

H₂S Corrosion

Even trace amounts of H₂S are highly corrosive, and since all gas pipelines contain trace amounts of water, this is a critical concern. H₂S reacts with carbon steel to produce hydrogen gas and iron sulfide (FeS). Hydrogen, being the smallest element, readily diffuses into steel, eventually causing embrittlement and cracking of the pipe.

H₂S corrosion typically presents as randomly scattered pits. The pits are round at the base with steep walls, while the top edges often flare out and may contain smaller secondary pits. Large pits can develop cracks at the bottom. Both steel surface and the corroded pits are generally covered with iron sulfide.

Figure 5: **H₂S Gas Bubbles Inside Metal Matrix Structure**



MIC (Microbially Induced Corrosion)

While microbes are typically not an issue in properly dried gas pipelines, they are still worth briefly discussing because they routinely operate within a galvanic corrosion cell.

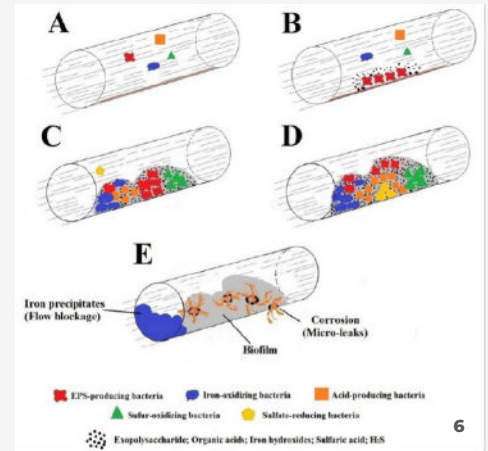
Microbially Induced Corrosion (MIC) results directly from microbial activity, generally classified into two main groups: aerobic and anaerobic (with facultative microbes also possible). Among these, sessile microbes – those that adhere to surfaces – are by far the most difficult to control.

Sessile microbes secrete a biofilm that protects them while they reproduce and cause primarily pitting-type corrosion profiles. These “holes” are very prone to highly localized failures in otherwise “good” pipe. Lastly, consider that microbes can be anaerobic, aerobic, and facultative (oxygen-hating, oxygen loving, and oxygen indifferent) and that the presence of oxygen influences which microbes grow.

5. (Zhang, L., Dorjpalam, S., Ji, G. et al. (2020).)

Figure 6: **Conceptual Illustration of MIC Progression in Steel Pipe**

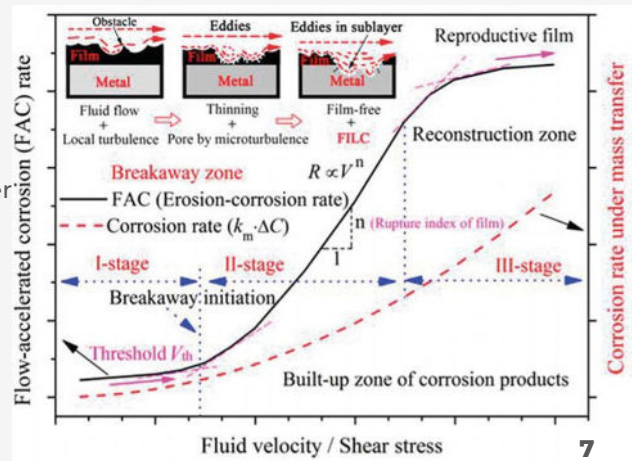
Figure 6 illustrates how microbes are substantially self-reinforcing if left undisturbed, with aerobic, anaerobic, and facultative microbes often able to exist in their own biome. The temperatures that pipelines operate at happen to traditionally overlap with Mesophilic temperature regimes for microbes (68-113° F). As you can see, once a biome has metastasized to a certain point, “colonies” break off and continue to spread corrosion to other portions of the pipeline. Lastly, while both anaerobic and aerobic microbes can create similar problems, aerobic microbes are significantly faster at it.



Abrasion Corrosion

Abrasion-related corrosion is a potential factor in nearly any corrosion scenario and should always be considered, as it often amplifies the severity of other corrosion mechanisms. The chart below illustrates why this form of attack is particularly troublesome and how easily it can accelerate overall material degradation.

Figure 7: **Corrosion Rates Under Mass Transfer**



III. The Role Oxygen Plays in Pipeline Corrosion

In the previous section, we reviewed why steel pipelines corrode, the key factors that influence corrosion, and some major corrosion mechanisms. In this section, we focus specifically on the role of oxygen (O₂) in pressurized steel pipelines and how it affects corrosion within oil and gas operations.

Oxygen (O₂) Corrosion

In the context of galvanic corrosion cells, oxygen is the single most important contaminant that must be strictly controlled and prevented from entering natural gas pipelines. Oxygen is an exceptionally aggressive corrodent and is rarely mitigated effectively by standard oilfield corrosion inhibitors. **This holds true whether water is present or not.** Oxygen-driven pitting tends to be broad, smooth, and overlapping, making it difficult to detect early and even harder to control.

6. (An Outline to Corrosive Bacteria, Coelho, Luana Cassandra, 2013/01/01)

7. (A Shengqiang Ma, Jiandong Xing, Hanguang Fu and Shizhong Wei, Cavitation - Selected Issues, 05 November 2018)

*What makes oxygen uniquely problematic is its ability to **accelerate every other form of corrosion**. While many corrosion mechanisms interact with one another, oxygen universally makes all of them worse!*

In addition, it's important to note that oxygen does not simply "add" to other forms of corrosion, such as CO₂ corrosion, but rather amplifies their effects in a way that is significant, though not necessarily equal in absolute magnitude to the primary mechanism.

Pit morphology in oxygen-enhanced corrosion usually reflects the underlying corrosion type that oxygen is accelerating.

Oxygen Impacts

Two common impacts from oxygen include:

Localized pitting can occur when oxygen becomes concentrated in specific areas of a pipeline, such as joints, welds, or low-flow zones. Rather than causing uniform wall thinning, however, oxygen enrichment promotes highly focused attack, producing deep pits that compromise wall integrity far more quickly than generalized corrosion. Because oxygen is concentrated in this scenario, the Galvanic cell has ample opportunity to form both on account of dissimilar metals forming the Anode/Cathode, and is further enhanced by the presence of oxygen. This allows iron to be the Anode, forcing it to corrode into rust, which is structurally weak and allows oxygen to permeate the rust layer and continue the attack when sufficient oxygen is present.

Microbially Induced Corrosion (MIC) is also influenced by oxygen ingress. Even small amounts of oxygen can shift the microbial balance within a pipeline, encouraging the growth of sulfate-reducing bacteria (SRB) and various scaling organisms. These microbes accelerate corrosion and may contribute to internal scaling or blockages, further complicating pipeline operations and integrity management. When combined with a reduced cross-sectional flow area, the increase in shear is often sufficient to detach these corrodent products elsewhere in the pipeline, allowing this cycle to begin again elsewhere and continue at the original site of MIC.

Oxygen Impacts on Pipeline Integrity

In steel pipelines, oxygen contamination commonly leads to wall thinning at the top of the pipe, particularly at the 12 o'clock position where oxygen tends to accumulate in vapor space. This localized exposure accelerates metal loss and shortens the pipeline's effective service life. As the wall becomes thinner, the pipeline becomes increasingly vulnerable to fatigue, crack initiation, and in severe cases, catastrophic rupture.

Beyond direct metal loss, oxygen introduces several **secondary effects** that compound corrosion risks. When oxygen interacts with hydrogen sulfide, CO₂, or existing microbial communities, it accelerates corrosion kinetics and destabilizes the protective chemistry inside the pipe. These interactions are especially problematic in areas with stagnant fluids, dead legs, or low-flow pipelines, where oxygen-rich pockets persist and create highly corrosive microenvironments.

Oxygen ingress also contributes to secondary effects, namely the formation of **rust particulates and scale**, which can break free and travel downstream. These solids foul valves, obstruct compressors, and can interfere with processing equipment, increasing maintenance requirements and operational downtime.

The table below quantifies and summarizes the impact of oxygen on carbon steel corrosion in different scenarios.

Table 3: **Effect of Oxygen on Carbon Steel Corrosion**

Solution	Oxygen Content	Hardness Value (Hv)	Weight Loss (g)	Corrosion Rate (mm/y)	Relative Corrosion Resistance
NaCl	With	7.900	0.220	0.150	Good
	Without	5.800	0.090	0.008	Excellent
H ₂ SO ₄	With	5.400	0.034	0.364	Good
	Without	3.500	0.010	0.0034	Excellent
HCl	With	6.900	0.020	0.1301	Good
	Without	1.600	0.000	0.0011	Outstanding

(A. Ismail, 2014)

In the **Sodium Chloride (NaCl) scenario (seawater)**, a carbon steel pipe loses 0.220 grams with dissolved oxygen present, 144% more than the 0.009-gram loss without oxygen.

In the **Sulfuric Acid scenario (H₂SO₄)**, a carbon steel pipe lost 0.034 grams with dissolved oxygen present, 240% more than 0.010-gram loss without oxygen.

In the **Hydrochloric Acid (HCl)** case, the loss was 0.020 grams with dissolved oxygen, as compared to zero without oxygen. Hydrochloric Acid is commonly used in a variety of applications in the oil and gas industry.

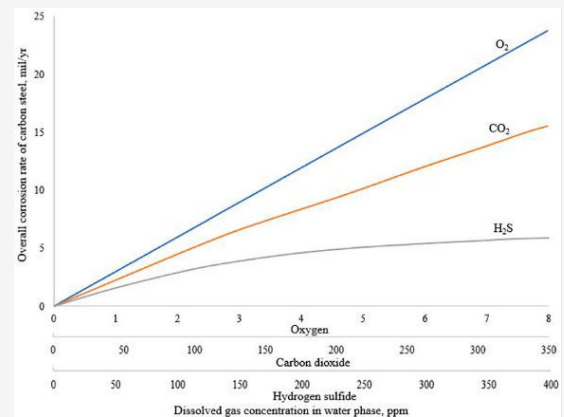
In **every case steel weight loss is higher when oxygen is present**, and significantly, the corrosion rate is very high (19 times more in the case of NaCl). With acids, the physical wall thickness loss is even greater.

Figure 8 demonstrates the significant differences in corrosion scenarios, given the presence of oxygen and without.

For example, at 5 ppmv of oxygen (a typical pipeline specification), results in 15 mil/year of corrosion rate – which is an ‘unsatisfactory’ Category III corrosion rate, but the equivalent CO₂ corrosion rate is ~340 ppmv and the graph does not have an equivalent H₂S corrosion rate to 5 ppmv of oxygen. Practical applications show that for this example of O₂ + CO₂, the final corrosion rate of the two equivalents is not 30 mils/year, but instead it is generally some other value such as 20-25 mils/year.

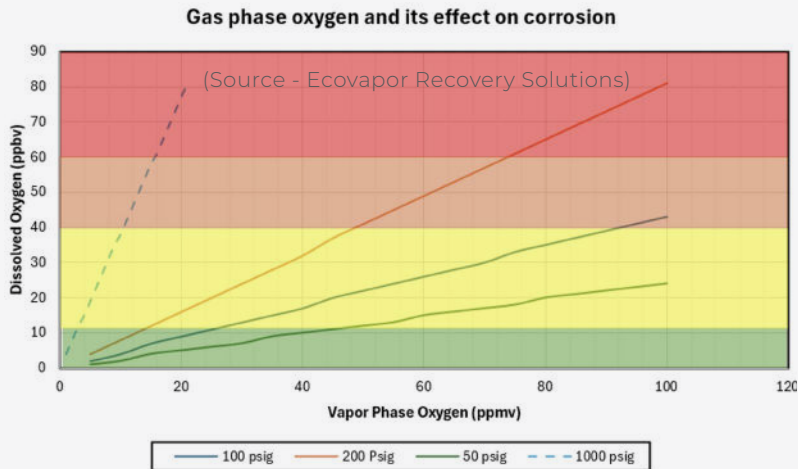
Figure 8: **Effect of Oxygen Concentration on Corrosion Rate of Carbon Steel in Seawater**

(A. Ismail, Effect of Oxygen Concentration on Corrosion Rate of Carbon Steel in Seawater, 2014)



Pressure and O₂ Corrosion. Figure 9 (next page)

illustrates vapor phase (x-axis) versus water phase (y-axis) and when oxygen represents a corrosion risk at various pipeline pressures (psig). **We recommend that operators take care to maintain vapor phase oxygen levels at ~5 ppmv or less (the green area).**

Figure 9: **Effect of Gas Phase Oxygen on Corrosion**

We strongly recommend keeping oxygen concentrations out of the red shaded area for any given pipeline pressure. Although the risk of rupture may not be immediate, because the timing of issues depends on a variety of external factors, prolonged operation at high pressures with elevated oxygen levels can prove dangerous.

While it is not possible to remove all water, the operational goal is to maintain a dew point of **-40 °F or lower** to significantly reduce the risk of condensation. Achieving this objective becomes increasingly challenging at lower pressures, where drying efficiency drops. Common gas-drying technologies include **adsorbent or desiccant dryers and glycol-based dehydration systems**.

IV. The Rationale for Oxygen Specifications in Pipeline Tariffs

A key question is – How does oxygen enter a natural gas pipeline in the first place? Oxygen can enter the oil and gas production system and pipelines from a variety of sources, but the most frequent methods are legacy facilities using crude oil and produced water tanks. Additionally, routine operational processes that can contribute oxygen are vapor capture, truck loading, tank strapping, etc.

Raw natural gas produced at the wellhead must be processed to remove contaminants such as CO₂ and capture more valuable vapor streams such as natural gas liquids (NGLs), which typically occurs at a gas processing plant. Oxygen inside of any gas processing plant is very dangerous, as several processes require extreme temperatures and the presence of oxygen introduces safety concerns and chemistry issues.

Processing Impacts. Oxygen contamination disrupts key gas-processing operations, including cryogenic NGL recovery, amine sweetening, and dehydration systems. Even small concentrations can destabilize process chemistry, reduce efficiency, increase the risk of upsets, and in some scenarios the potential for explosions.

Hydrocarbon Instability. In liquid hydrocarbons, oxygen can initiate polymerization reactions and contribute to broader instability issues. These reactions create gums, deposits, and fouling that compromise product quality and system performance.

Operational Costs. The presence of oxygen drives higher corrosion rates, increases the likelihood of equipment failures, and leads to unplanned downtime. Off-spec gas rejection and additional maintenance requirements further elevate operating expenses (OPEX), directly impacting the economic performance of pipeline and processing systems.

Operational Considerations

In addition to safety considerations, pipeline operators must also take into consideration the negative downstream impacts of oxygen contamination.

Operators, regulatory agencies, and other key stakeholders all have compelling reasons to influence and establish pipeline gas quality specifications, with public safety and operational integrity being the two most prominent drivers. Ensuring that gas delivered through pipelines meets quality standards is critical for minimizing safety risks, preventing corrosion and mechanical failures, and maintaining reliable energy delivery to consumers and industry.

According to the Pipeline and Hazardous Materials Safety Administration (PHMSA), operators reported approximately 892,077 miles of natural gas transmission and gathering pipelines in service at the end of 2024, the most recent reporting period, 117% more than the previous year. (Source: [Annual Report Mileage for Natural Gas Transmission & Gathering Systems](#)). Readers should note, however, that the massive increase was not necessarily related to a sudden surge in new pipeline construction, but instead reflects that PHMSA changes how it aggregates and reports pipeline segments. That is, certain lines that were previously reported under a separate category (e.g., “Transmission” or other segments) were re-classified within Onshore Gathering totals in the published table beginning with the 2024 dataset.

PHMSA made a similar reclassification affecting reported 2022 pipeline mileage, which resulted in an increase of approximately 95,000+ miles of pipe from a change in reporting requirements that expanded the definition and reporting coverage for onshore gas gathering lines (creating Type C and Type R classifications and requiring annual/incident reporting for many previously unreported lines). When operators began filing the new annual-report data (first

reports covering 2022 operations, filed in 2023) the reported onshore gathering-line mileage jumped from approximately 11.4 thousand miles to approximately 106.9 thousand miles, which is a classification/reporting change, not a sudden construction wave.

Reporting nuances aside, the reported pipeline mileage reflects the extensive network of federally regulated pipeline infrastructure, though it does not include certain intrastate gathering lines or “in-plant” systems not subject to the same reporting requirements. With nearly one million miles of natural gas pipelines in operation nationwide, the potential for corrosion and other integrity issues to impact public health and the security of energy infrastructure is substantial and underscores the importance of robust gas quality and corrosion control standards

Quality Standards for Public Safety

The PHMSA, operating under the Department of Transportation, is the primary authority regulating pipeline safety (49 CFR Part 192), which includes corrosion prevention. PHMSA does not mandate exact oxygen concentration limits, leaving it up to pipeline operators, but the agency does require operators to control internal corrosion, which typically involves limiting oxygen concentration in natural gas.

Although not all pipeline operators publish their natural gas quality specifications publicly, typical oxygen concentrations for steel transmission pipelines range between 0.05–0.2% by volume (500–2,000 ppm) and are more stringent for sensitive segments (e.g., storage, LNG, high pressure) ranging from 10-50 ppm or lower. For example, the gas quality specification for the Panhandle Eastern Pipe Line operated by Energy Transfer Partners is 50 ppm (Source: [Panhandle Eastern Pipeline Tariff](#)).

The states also play a role in pipeline safety, although it is rare for individual states to impose specific oxygen limits, leaving the exact concentration up to pipeline operators. In fact, we are aware of only two states that impose oxygen restrictions on natural gas pipelines – Michigan and Missouri.

For example, current limits on oxygen concentration in pipelines regulated by the Michigan Public Service Commission (MPSC) are set at 0.0005%, or 5 ppm, and are the strictest in the U.S. Although there isn't a publicly cited named pipeline explosion or incident that triggered the stringent oxygen standard, ostensibly it was put into place to manage corrosion risks primarily around underground gas storage reservoirs where oxygen combined with moisture can accelerate internal corrosion of steel infrastructure. Interestingly, the [Pipeline Safety Trust of Michigan](#) reported that 17% of pipeline failures nationwide are due to corrosion and 36% are the result of equipment failure.

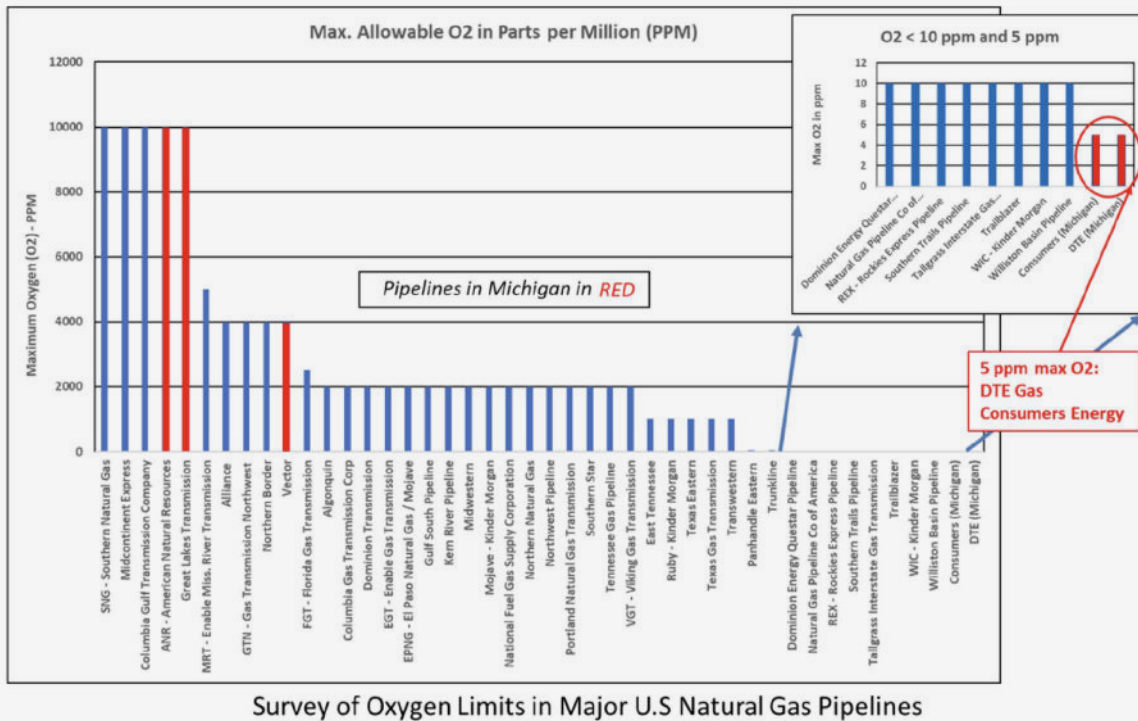


Figure 10: **Survey of Oxygen Limits in Major U.S. Natural Gas Pipelines**

Figure 10 above summarizes the oxygen concentration limits for several U.S. pipelines, which vary widely. Source: [Barriers to Renewable Natural Gas \(RNG\) in Michigan, Quantalux, January 22, 2022.](#)

Although Missouri has a statutory limit on oxygen concentration limit of 1.0% by volume, the federal government assumed regulation of the state’s natural gas pipelines in early 2025, citing the fines for violations with too low and not consistent with federal requirements.

Michigan has assumed a leadership position on pipeline safety, and we note that the industry takes corrosion risk seriously and employs strategies to mitigate the risk. However, given the nature of corrosion and the multiple corrosion mechanisms, preventing oxygen ingress into natural gas pipelines remains an ongoing, critical objective.

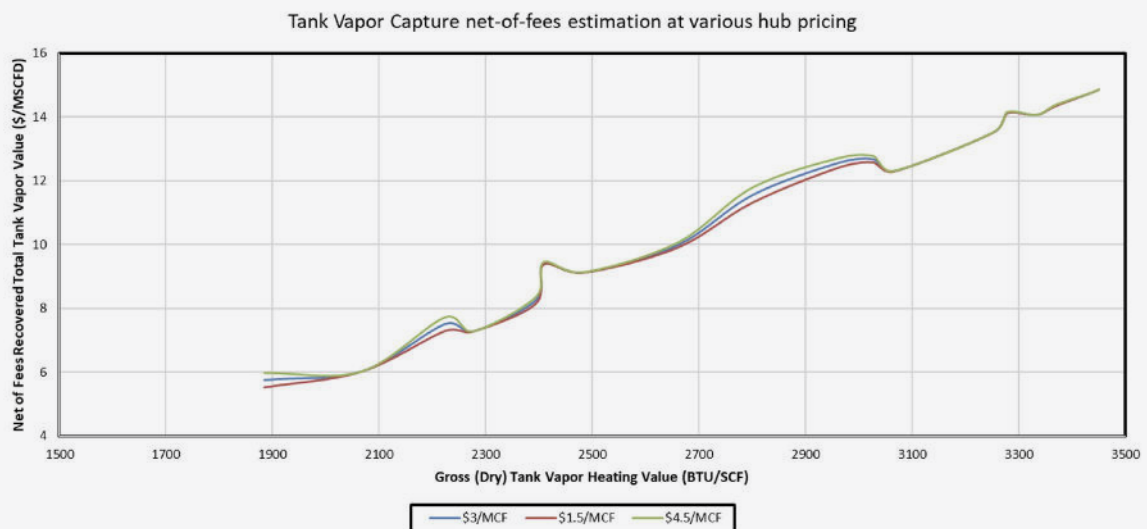
“Slamming” the Door Shut on Oxygen

To enforce oxygen restrictions, many gas gathering system operators employ a “slam valve,” also known as an emergency shutdown valve (ESD valve) or fast-acting shutoff valve, designed to immediately and automatically stop the flow of gas when unsafe conditions are detected. In the context of preventing oxygen-contaminated gas from entering a gathering or sales line, a slam valve serves one critical purpose: “slam shut” when instrumentation detects off-spec gas quality, such as elevated oxygen content. This prevents contaminated gas from moving downstream into sales lines, transmission lines, processing facilities, and customer delivery points.

A major factor in maintaining oxygen levels within specification is operational reality – When gas production is curtailed or “slammed” to prevent contaminated gas from entering the sales line, **producers typically cannot continue selling crude oil or condensate.** Because most wells produce oil and gas as combined stream, shutting in gas effectively shuts in the entire well, causing immediate downtime and potential loss of revenue, creating strong disincentives to curtail production even when oxygen contamination is present.

Additionally, when the slam valve shuts sales line, gas production and tank vapors are automatically routed to a flare or enclosed combustion device (ECD) to burn the off-spec gas and convert it into less harmful substances. **Unfortunately, this also means burning away what is typically the most valuable gas stream on the well site – BTU-rich tank vapors,** resulting in a loss of production and revenue.

Figure 11: Value of Oxygen Removal from Captured Tank Vapor



(Source - Ecovapor Recovery Solutions)

V. Mitigation Approaches for Oxygen Contamination

Industry has developed several strategies for mitigating oxygen contamination in pipelines and other production infrastructure.

Source Control. The best way to stop oxygen contamination is to prevent it from entering the production and transportation system in the first place. Eliminating the source of oxygen involves several strategies, including:

- Proper construction and rigorous Leak Detection and Repair (LDAR).
- Leak prevention in gathering systems and atmospheric tanks.
- Preventing vacuum conditions that draw air into pipelines.
- Inert gas blanketing to displace oxygen in tanks.
- Active monitoring of truck offtake assets.

As a practical matter and despite the best precautions and facility design, oxygen can still enter production systems from a variety of causes, including pinhole leaks in tanks, tank breathing and expansion, worn seals, and oxygen coming out of solution in crude oil during storage and accumulating in the head space.

Monitoring. Various methods can be employed to detect the presence of oxygen contamination:

- Deployment of online oxygen analyzers for continuous surveillance.
- SCADA integration to provide real-time alarms and trending for early intervention.
- Periodic sampling to give a “snapshot” view of oxygen contamination.
- Corrosion coupons on areas suspected of oxygen corrosion with regular, periodic monitoring of said coupons.

Treatment Technologies. Oxygen mitigation measures commonly include treatment techniques for rendering oxygen inert, removing it, and/or combating corrosion, including:

- **Liquid Scavengers.** Provide moderate effectiveness for dissolved oxygen but require continuous chemical injection, increasing points of failure. Risks include over/undertreatment, failure to treat, handling hazards, and safety concerns (e.g., asphyxiation).
- **Disposable Catalytic Scavenger.** Solid media catalysts, typically using compounds based in iron, copper, zinc, manganese and other substances, used to remove oxygen (one-time use).
- **Corrosion Inhibitors.** Most oilfield corrosion inhibitors do not work specifically for oxygen corrosion.
- **Catalytic Removal Systems.** Provide continuous removal with lower recurring costs, no consumables, and minimal operator intervention.

VI. The Solution: ZerO₂® Oxygen Removal Technology from EcoVapor

Technology Overview

The **ZerO₂® system** is a proprietary catalytic oxygen removal system specifically engineered for natural gas applications, including:

- **Oil & Gas.** Eliminates oxygen from tank vapor gas from multiple sources (i.e., oil storage tanks, produced water storage tanks, truck loadouts, etc.), allowing you to sell what is typically the most valuable gas on the well site – high-BTU tank vapor gas – instead of flaring it or losing it to venting.
- **Renewable Natural Gas (RNG).** Upgrading biogas feedstock from agricultural digesters and landfills is a critical step for preparing biogas for commercial sale as RNG. ZerO₂ technology eliminates oxygen from biogas and landfill gas for meeting strict pipeline specifications for monetizing these valuable gas streams.

The ZerO₂ system continuously reduces oxygen to **below even the most stringent pipeline tariff limits**, ensuring compliance even under variable operating conditions. The ZerO₂ system can economically achieve the most stringent oxygen concentration restrictions in the U.S., like those imposed by the MPSC in Michigan (<5 ppm) for enhancing public safety and energy security.

ZerO₂ technology is reliable, having accumulated a long track record of 99.5%+ mechanical availability from more than 300 units deployed across more than 15 states serving oil & gas production and biogas operations.

Advantages

- Significantly reduce the “hidden” risk of oxygen-related corrosion risks to gas gathering systems, transmission lines, and infrastructure.
- Capture 100% of the BTU-rich vapor coming from oil storage tanks, produced water storage tanks and truck loadouts.
- Meet Zero Routine Flaring initiatives, including flareless startups.
- MobileZerO™ solution allows you to move the unit from location to location.
- Achieve high reliability and uptime, with no moving parts, minimal preventative maintenance, and field-wide runtime >99.8%.
- Right-size treating capacity, with straightforward installation and modularity for operational flexibility.
- Generate more net revenue from gas & NGLs sales.
- Reduce or eliminate tank flaring and associated emissions.
- Improve safety by actively managing tank battery pressures.
- Recover your investment in less than a year.
- Eliminate the risk of shut-ins due to excess O₂ levels.
- Ability to treat up to 4.75% oxygen without a recycle loop as a continuous process.

Operational Benefits

- Guarantees compliance with stringent tariff oxygen specifications, despite widely varying incoming oxygen concentrations.
- Protects pipeline integrity and replacement OPEX by mitigating oxygen-driven corrosion.
- Prevents downstream operational upsets, minimizing downtime and gas rejection.
- Extends economic life of assets, improving ROI for marginal wells and gathering systems.

VII. Conclusion

Oxygen contamination poses a unique and severe corrosion risk in natural gas pipelines, with consequences that extend beyond equipment damage to catastrophic safety incidents. The industry's strict oxygen specifications reflect the seriousness of these risks.

While source control and monitoring are important, treatment is often unavoidable. The Zero₂ system delivers a proven, reliable, and cost-effective catalytic solution to oxygen removal, enabling operators to:

- Maintain compliance with pipeline tariffs.
- Protect infrastructure from accelerated corrosion.
- Protect people and property from oxygen-related risks downstream of the pipeline.
- Enhance operational efficiency and safety.

Oxygen Corrosion Risk Is Real. The Solution Is Proven.

Even trace oxygen levels can accelerate corrosion, compromise assets, and create downstream safety hazards. As oxygen specifications tighten, operators need solutions that move beyond detection to prevention.

Contact EcoVapor today to find out if the Zero₂ oxygen removal solution is right for your operations.

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