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Uncertainties in Relation to Corrosion Management of CCUS Projects and Developments in Laboratory Testing

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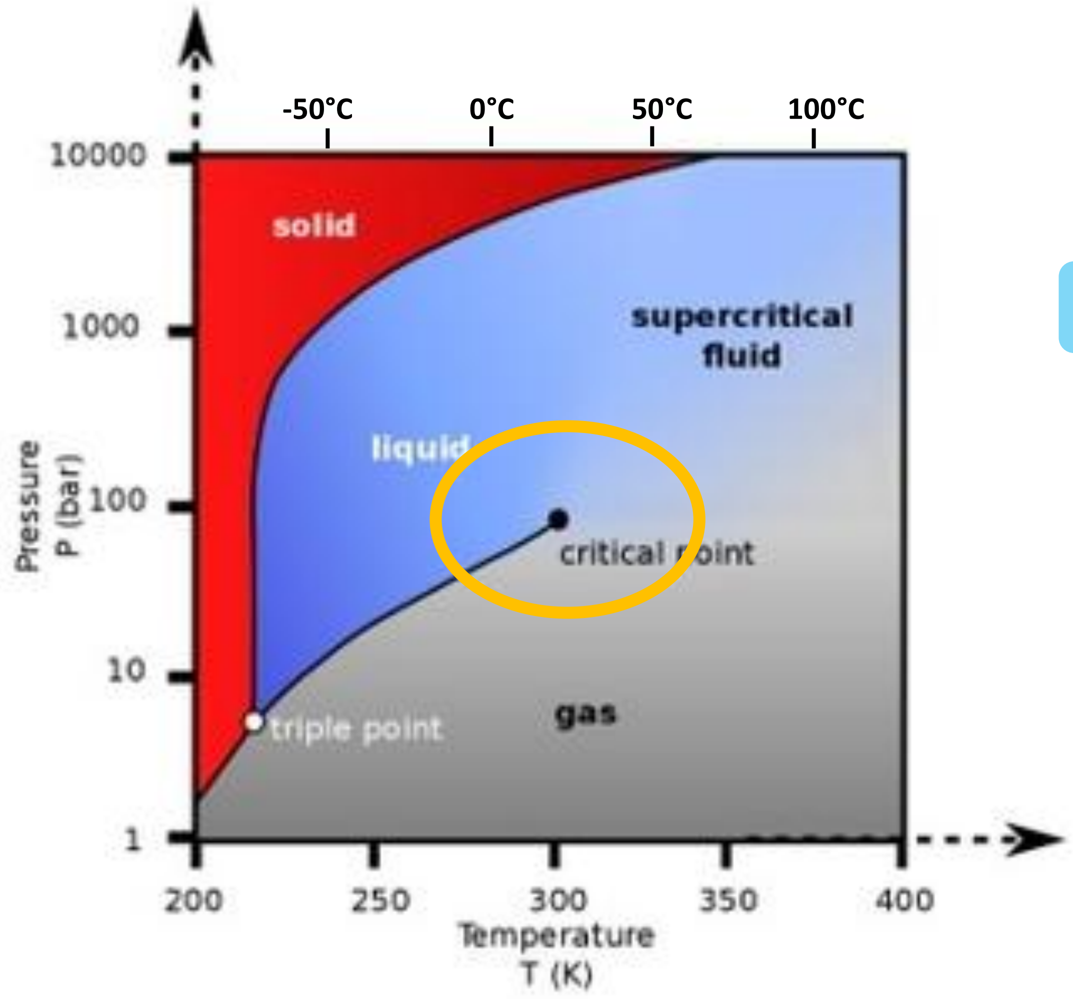
Corrosion Controlled. Materials Assured.

Properties of CO_2



Carbon capture, transport, utilisation and storage (CCUS) relies on the properties of dense phase / supercritical CO_2.

- Triple Point: 5.1 bar / 216 K (-57 °C)
- Critical Point: 83.8 bar / 304 K (31°C)

Pure & dry CO_2 (i.e. with no contaminants and no water) is essentially unreactive with metals / alloys; but can react with non-metallics.

Where sufficient water is present a free water phase can form which, due to dissolved CO_2, can be very corrosive to metals / alloys.

In the presence of some impurities (such as SO_x, NO_x, H_2S, O_2 and others) free acids can also form leading to increased corrosion.

What are the Uncertainties associated with CCUS?

Over the past few years there has been major developments in the understanding of the issues associated with integrity & corrosion issues for CCUS systems.

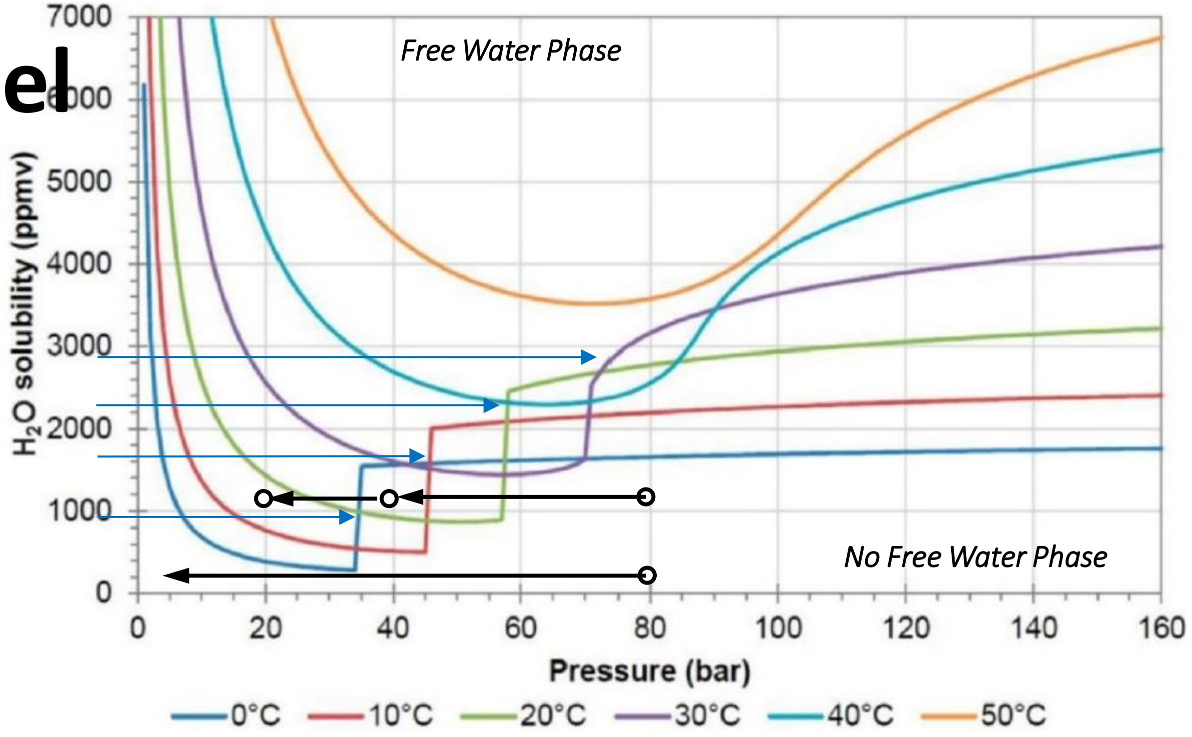
However, there are still many areas were there are unknowns including:

- Critical concentrations of different contaminants (impurities) and their impact on the corrosion rate of carbon steel.
- Impact of different contaminants (impurities) on localised corrosion / stress corrosion cracking of stainless steels / corrosion resistant alloys (CRAs).
- Impact of process upsets (i.e. shutdowns / start-ups) on corrosion conditions.
- Compatibility of non-metallic materials, both as seals and for pipework, with CCUS conditions.
- The applicability / reliability with respect to corrosion modelling (prediction) of corrosive conditions (general & localised).

Corrosion threats for carbon steel

Main threat to carbon steel in CCUS systems is directly related to the presence of a free water phase.

Critical water content to form free water phase is dependent on temp & pressure, as shown in a water solubility diagram here [1].



Mol Fraction H_2O in pure CO_2 different temp / pressures [1]

For conditions below the lines ***No Free Water***, above the lines ***Free Water*** is present

For example,

- For water content of 1250 ppmv
  - At 80 bar - No free water phase at all temps (> 0°C)
  - At 40 bar - No free water phase if temp > 25°C (or < 0°C) but free water phase if temp 5 to 25°C
  - At 20 bar - No free water phase if temp > 15°C, but free water phase if temp < 15°C
- Whereas, for water content of 200 ppmv, then no free water phase at any pressure or any temp (> 0°C)

In the absence of free water then no corrosion occurs.

[1] Fig 1 from Simons etal, in Engineering Failure Analysis 181 (2025) paper 109905

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Corrosion threats for carbon steel

We first carried out laboratory tests [2] in supercritical pure CO_2 (in the presence of water) several years ago which showed carbon steel corrosion rates up to 25 mm/y, depending on conditions.

- This also showed that corrosion inhibition was feasible (as shown in Fig A) but only at very high dosage levels (200 to 1000 ppm).

Recent published work [3] confirms typical carbon steel corrosion rates (as shown in Fig B).

Initially corrosion studies were mainly aimed at CO_2 extraction and injection systems (as part of Enhanced Oil Recovery projects) or for extreme high CO_2 content pipelines. Hence only considered expected levels of water & H_2S in the stream.

However, new industrial carbon capture is aimed at taking CO_2 from a wide range of industrial sources and will include various contaminates / impurities.

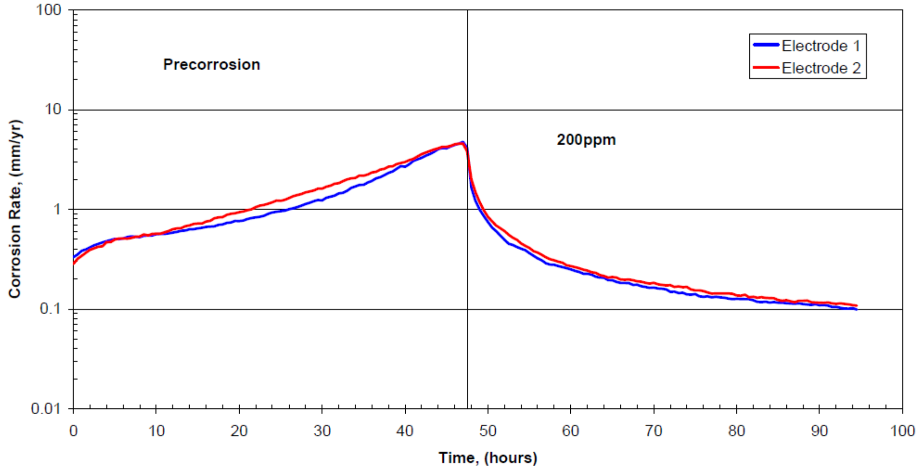


Fig A. Corrosion Inhibition efficiency at 200 ppm conc. (pure CO_2, 120 bara, 60°C, 0.1% NaCl) [2]

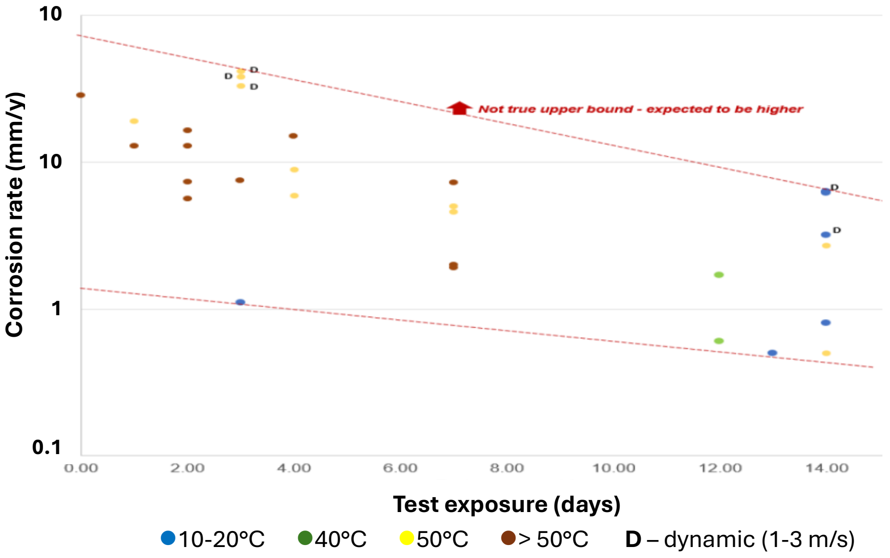


Fig B. Published corrosion rates in pure dense phase CO_2 (varying temp, pressure & time exposure) [3]

[2] Turgoose, John et al, paper 4048, NACE Corrosion 2014, San Antonio, 2014,
[3] Fig 4 from Sanda et al, paper 00345, AMPP Corrosion 2025, Nashville, 2025,

Corrosion threats for carbon steel

Because many CCUS projects will be taking CO_2 from a range of different industrial sources, including power generation and cement works, this will result in a significantly wider range of additional contaminates (impurities) which could be present.

These impurities will vary over time, depending on which plants are operating / not-operating and the extent of any pre-processing (cleaning) that will be carried out.

- ***It should also be noted that any impurities will typically only be present at trace levels (i.e. < 100 ppmv / 0.01 mol%).***

The impact of impurities on corrosion to carbon steel was highlighted in the 2023 AMPP guidelines [4] and has been taken into account in the published CO_2 quality specifications for current industrial carbon capture & sequestration projects in Europe, including:

- Northern Lights (Longship Project Norway) [5]
- Teesside (Northern Endurance Partnership, UK) [6]

[4] AMPP 21532-2023 *Guidelines for Materials Selection and Corrosion Control for CO_2 Transport and Injection*

[5] Northern Lights Specifications for the Cargo (liquefied CO_2) – 2025 https://norlights.com/wp-content/uploads/2025/06/Liquid-specification-2306251.pdf

[6] Northern Endurance Partnership (Teesside) CO_2 Pipeline Entry Specification. https://northernendurancepartnership.co.uk/wp-content/uploads/2025/04/PES-NEP00-EN-SPE-000-00001-Public-B02.pdf

Current recommend limits for impurities in CO2 streams

Component	AMPP CCS guidelines [4]	Northern Lights [5]	Teesside [6]
Alcohol (Methanol, Ethanol)	not defined	< 30 ppm	< 50 ppm
Amine (CH_3NH_2, $(CH_3)_2NH$, or $(CH_3)_3N$)	not fully understood	≤ 10 ppm	≤ 1 ppm
Ammonia (NH_3)	unknown	≤ 10 ppm	≤ 10 ppm
Carbon monoxide (CO)	≤ 1,000 ppm	≤ 100 ppm	≤ 1,000 ppm
Glycol (MEG, TEG, DEG)	not defined	≤ 0.2 ppm	≤ 1 ppm
Hydrogen (H_2)	unknown	≤ 50 ppm	≤ 0.75mol%
Hydrogen cyanide (HCN)	unknown	≤ 100 ppm	-
Hydrogen sulfide (H_2S)	≤ 10 ppm	≤ 1 ppm	≤ 5ppm
Mercury (Hg)	Unknown	≤ 0.0003 ppm	≤ 0.0025 ppm
Nitric oxide / nitrogen dioxide (NO_X)	10 ppm	≤ 1.5 ppm	≤ 5 ppm
Nitrogen (N_2)			
Organic Acids (e.g. HAc)	Unknown	-	-
Oxygen (O_2)	≤ 20 ppm	≤ 10 ppm	≤ 10 ppm
Sulfur dioxide / sulfur trioxide (SO_X)	10 ppm	≤ 10 ppm	≤ 10 ppm
Water (H_2O)	100 ppm	≤ 30 ppm	≤ 50 ppm

Impact on water phase

Known Increase Corrosion

Unknown Increase Corrosion

Inhibitive effect

An increase in CO can also lead to Stress Cracking in carbon steels (X65) [7]

[7] Mendibide, *Assessment of the risk of SCC of pipelines transporting CO_2 in presence of CO Contamination*, AMPP Corrosion 2024, paper 00044

Quality Control Issues for CCUS

- As previously noted, the expected impurities are likely to be present at only ***trace levels*** (i.e. concentrations less than 100 ppmv / 0.01 mol%) but will still have a significant impact on overall corrosion rates.
- But this raises the question as to the reliability of any CO_2 analysis to detect presence / variation in these trace levels, and the ability (or otherwise) to flag excursions above specified limits.
- Also, if impurities exceeding the specific critical level are detected – *what action can then be taken?* (other than to reject to stream)?

Impact on Laboratory Testing

Effect of trace levels of impurities also creates problems associated with laboratory testing, since ensuring that the actual concentration of low-level components in the gas stream is vital to ensure reliable and consistent results [8].

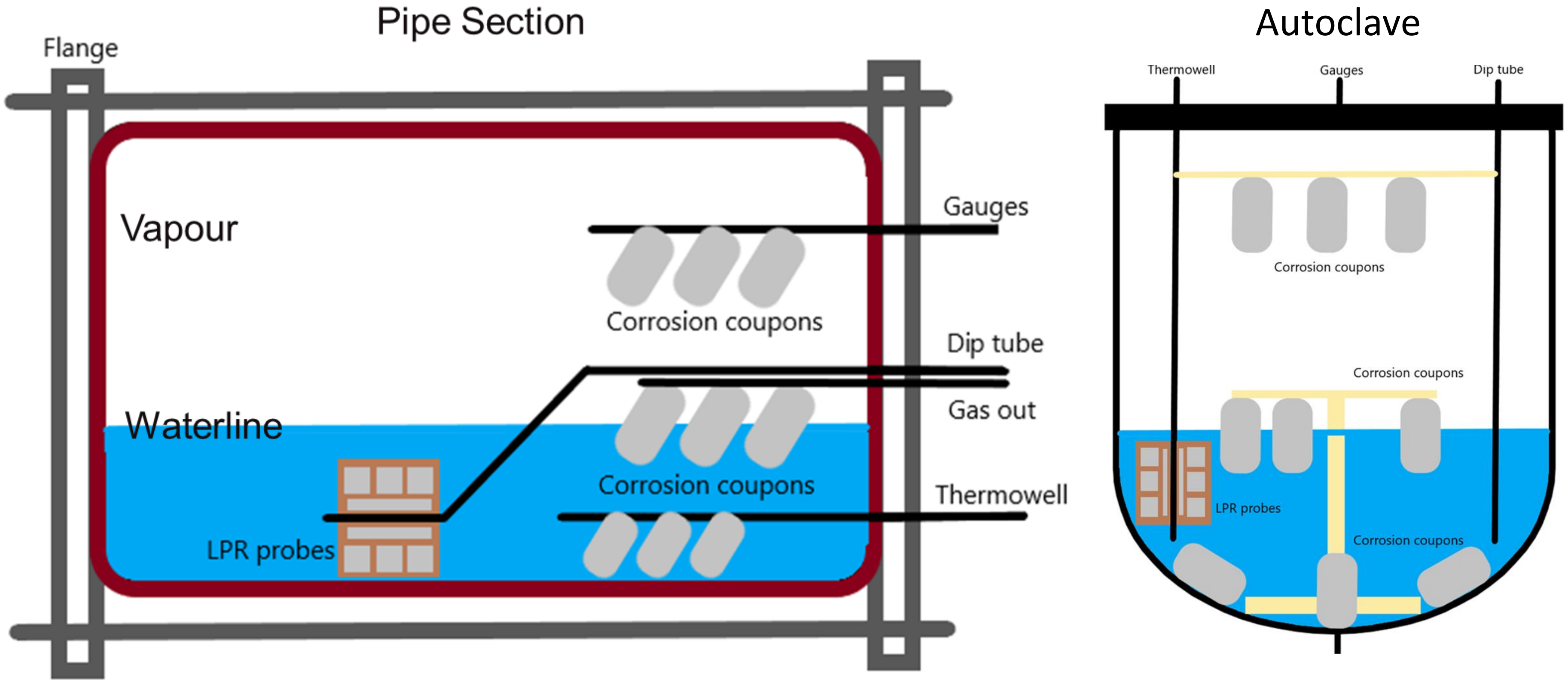
At this time numerous research & testing labs, including our own, are developing procedures to allow testing for different impurities at reliable (but trace) concentration levels.

This includes assessing the impact of process upsets (such as start-ups / shut-downs) on overall corrosion threat. In this the question relates to what corrosion rates occur during shut-ins compared to operating conditions, and what this implies with respect to corrosion allowance requirements [9].

[8] S.K. Kairy et al, Corr Sci 214 (2023) 110986

[9] P Wood & R Morana, paper C2026-00108 at AMPP Corrosion 2026

Experimental Set-Up “Shut-In”



Two different experimental set-ups used

- **Full Pipe section (CS X65)**
  - dia 10” (250 mm), length 200 mm
  - Liquid/CS surface ratio : 4.2 mL/cm^2
  - Corrosion Coupons + LPR Probes
- **Autoclave (Alloy C276)**
  - Capacity 8 L
  - Liquid/CS ratio : 22.7 mL/cm^2
  - Corrosion Coupons + LPR Probes

Testing for shut-in conditions, used 2 different test set-ups. In both cases:

- CS Corrosion coupons
  - 50 x 25 x 2 mm
  - Positioned in:
    - Vapour Space
    - Waterline
    - Submerged
- LPR probes only located within water phase.
- **Test solution:**
  - 1000 mg/L chloride
  - 3 L volume
- **Test Conditions**

Temp	25°C ± 3°C
Pressure	29.6 barg
O_2	10 ppmv
SO_2	25 ppmv
NO_2	10 ppmv
CO_2	Balance

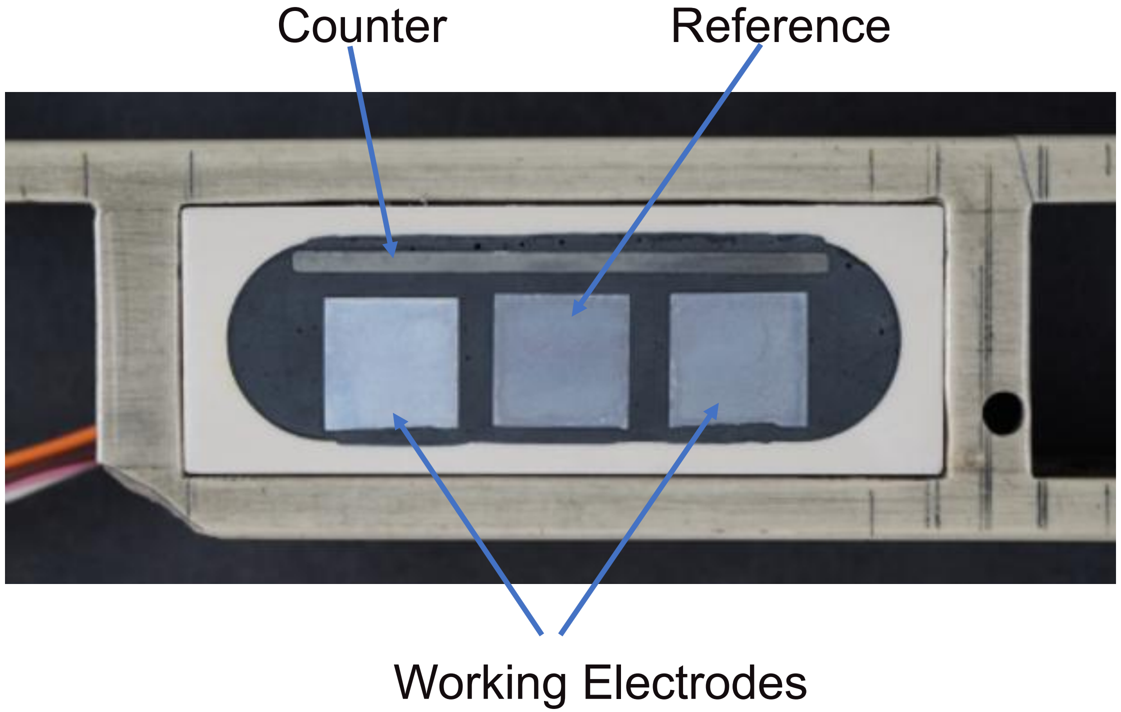
Gas Loading Procedure

Step	Gas	ppm at Test Press	ppm in Gas mix	Start Pressure (bara)	End Pressure (bara)	ppGas (bara)
1	CO_2	-	100%	0	26.8	26.8
2	SO_2	25	750	26.8	27.8	0.00075
3	NO_2	10	300	27.8	28.8	0.0003
4	O_2	10	300	28.8	29.8	0.0003
	Total CO_2		~100%	0	29.80	29.80

- Major challenge is to ensure the contaminant (SO_2, NO_2& O_2) at trace levels are maintained.
- Achieved by using separate certified gas mixes for each contaminant.
- Test gases were added in sequence and pressures stabilized over 60 mins.
- Higher concentration mixes were needed as required values were below obtainable limits.
  (i.e. 1 bar of 750 ppmv SO_2 mix at full test conditions gives the required 25 ppmv test value)
- **Test gases replaced on a weekly basis.**

Linear Polarisation Resistance (LPR) Testing

LPR testing at **30-minute intervals,** was used to measure corrosion rates in the water phase throughout the 30-day exposure.

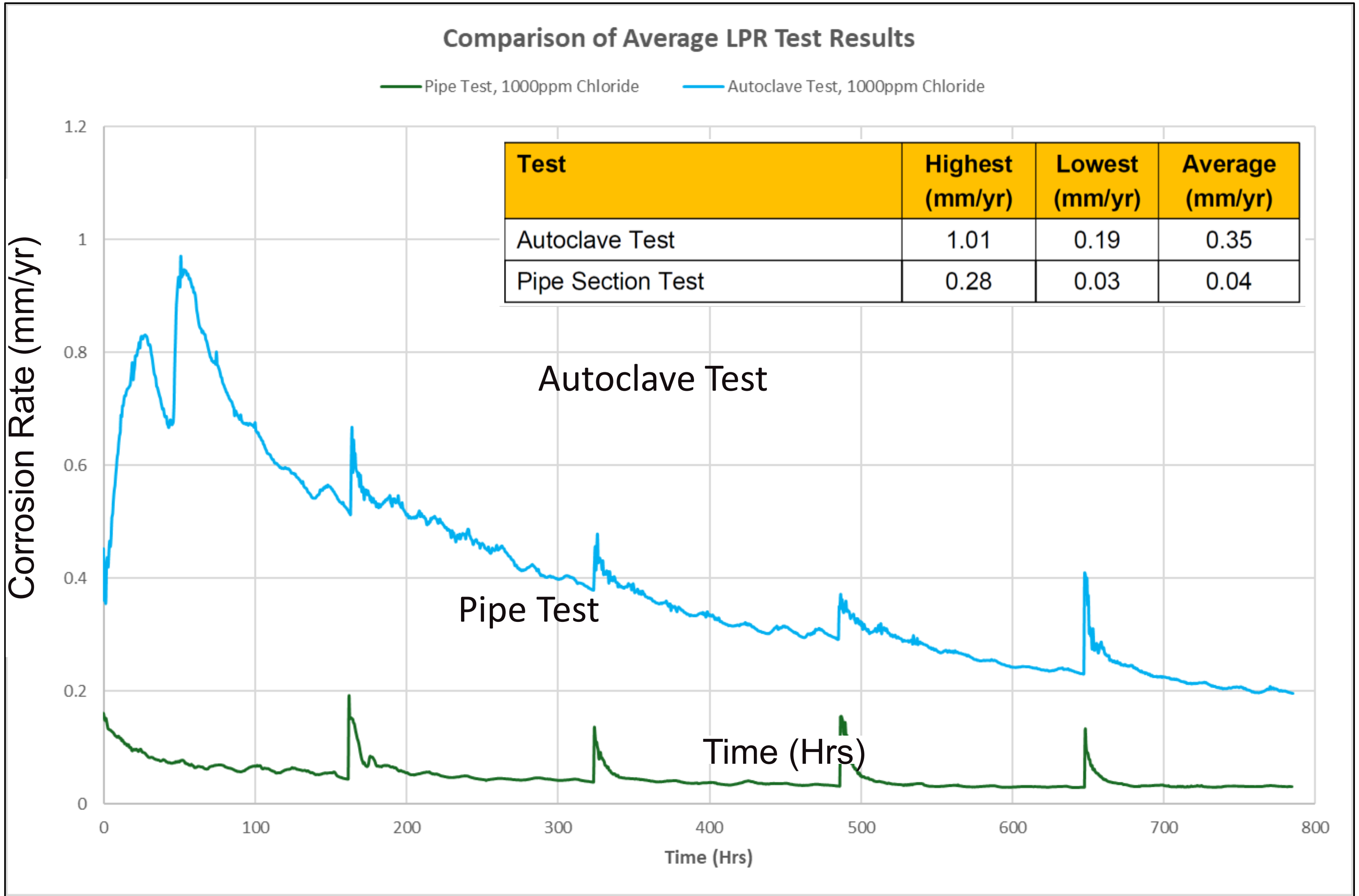


A three-electrode technique was utilized,

- **Counter electrode:** 316L
- **Reference electrode:** pipeline material (pseudo reference).
- **Two working electrodes:** pipeline material (1 cm x 1 cm x 1 cm blocks) for duplicate result generation.

- **Two probes** in each vessel, giving a total of **four LPR readings** during the exposure period.

LPR Results Comparison



Test	Highest (mm/yr)	Lowest (mm/yr)	Average (mm/yr)
Autoclave Test	1.01	0.19	0.35
Pipe Section Test	0.28	0.03	0.04

- Corrosion rates from all 4 LPR probes in each test gave similar results (just single trace shown here).
  - **Autoclave test** showed exponential decrease in rate. No final (equilibrium) rate within the test period (780 hrs).
  - **Pipe section test** reached a final (equilibrium) rate after approx. 350 hrs exposure.
- Corresponding coupon rates from pipe section compatible with LPR. Whilst for Autoclave approx. 40%
- Spikes are cause by the weekly gas re-charge (oxygen reaction). All short duration (< 10 hrs) before returning to baseline rate.

Corrosion coupon Corrosion Rates

- Corrosion coupons of dimensions 50 mm x 25 mm x 2 mm.
- Surface finish ≤ 0.25 µm.
- Following exposure chemically cleaned using ASTM G1 standard.
- Weight loss assessment for calculation of general corrosion rate in mm/year.
- Coupons were examined at up to 400x magnification using 3D profilometry microscope.
- All observed features were photographed and depth measured; pitting was evaluated in accordance with ASTM G46.
- For water phase the comparison to LPR results differs between the 2 test set-ups

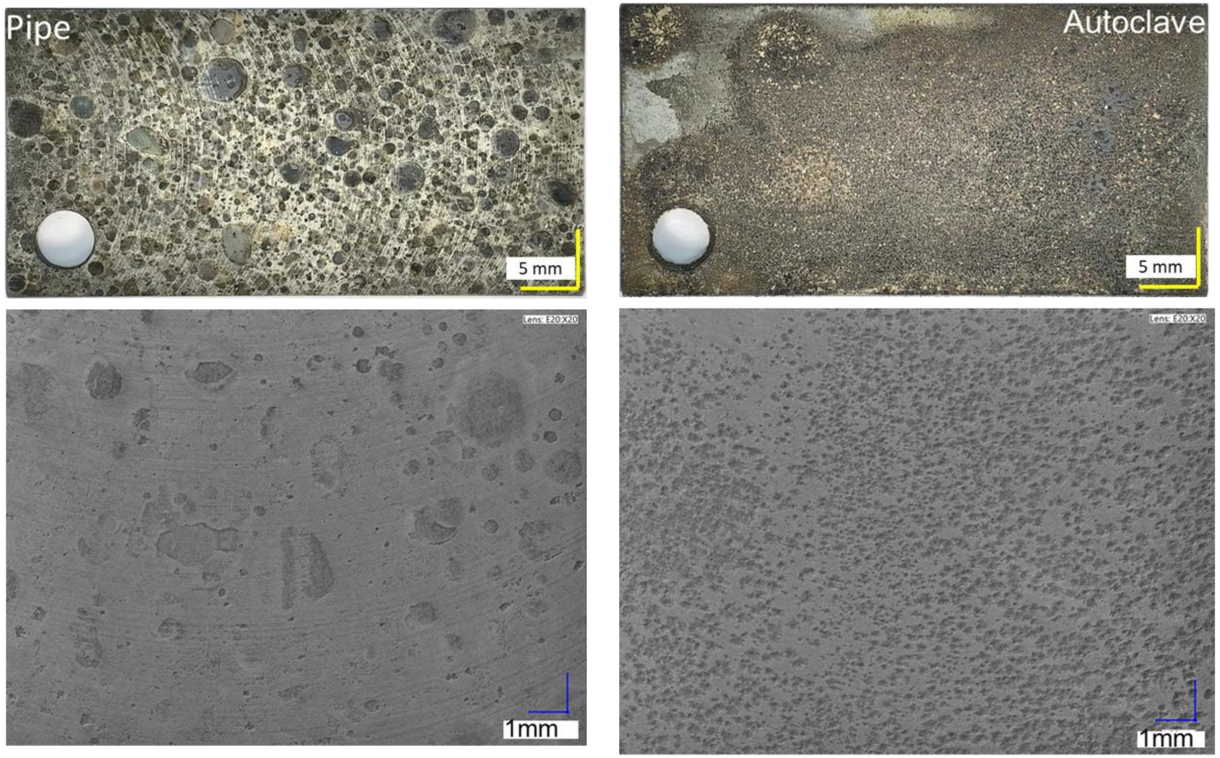
Comparison of LPR and Corrosion Weight Loss Coupons

Test	LPR (mm/yr)	Corrosion Coupons (mm/yr)
Autoclave Test	0.35	0.15
Pipe Section Test	0.04	0.04

Corrosion Coupons – Vapour Phase

Also difference in condition on coupons between the 2 tests!

- In vapour phase the autoclave test had the deepest pitting.
- Pits were irregular.
- Surface was uniformly covered in pits.
- The maximum depth recorded was 20 µm, Equivalent to 0.24 mm/yr.



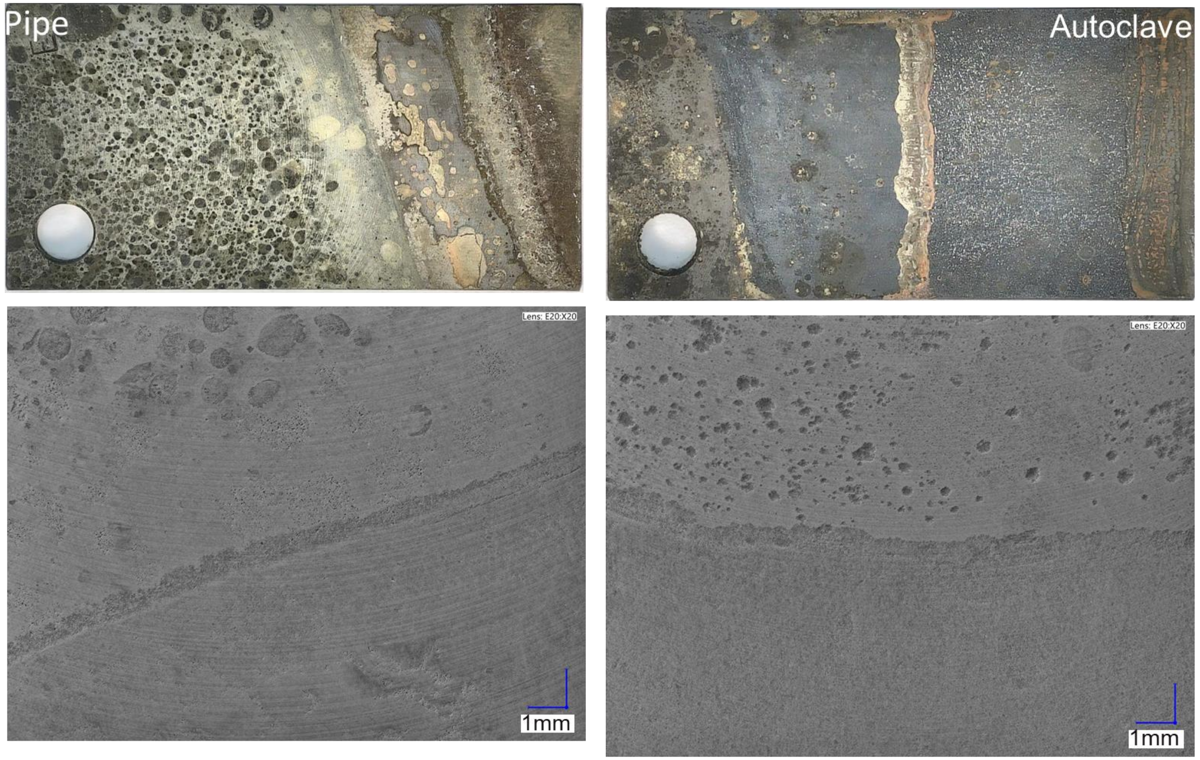
Corrosion Coupons – Waterline

Attack on the water line coupons was deepest with autoclave.

Waterline not a single artifact:

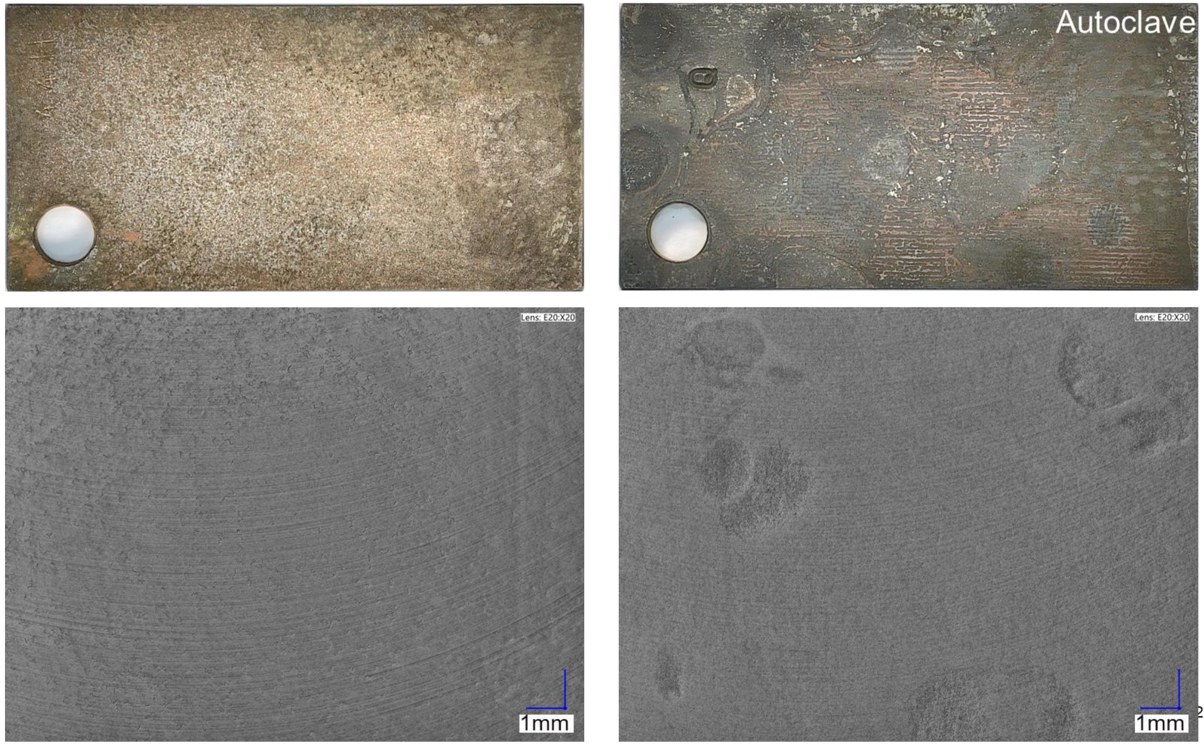
- Covered a length of approx. 10 mm.
- Trench feature with deepest attack at vapour phase boundary.
- Decreasing in depth below waterline.

The maximum depth of attack recorded was 80 µm. Equivalent to 0.96 mm/yr.

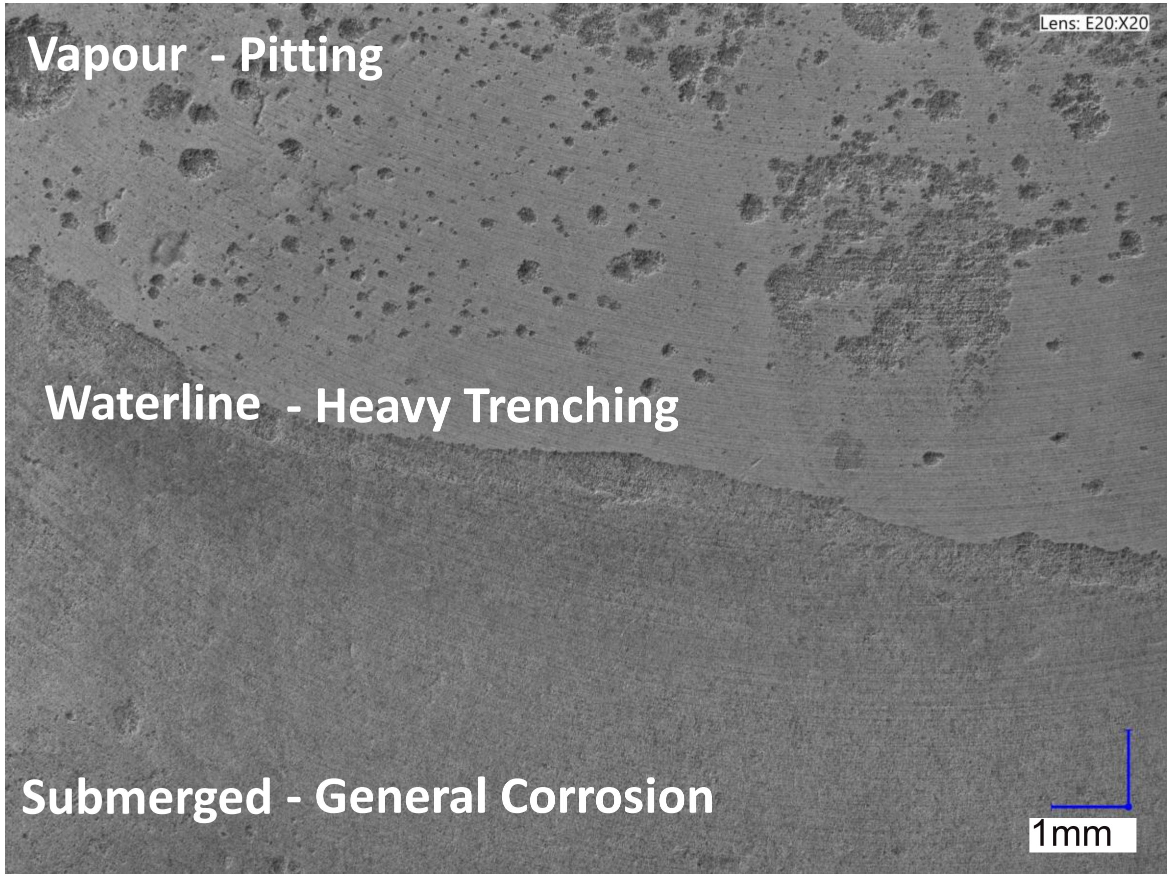


Corrosion Coupons – Liquid Phase

- The submerged region was mainly **uniform corrosion.**
- Some localized attack occurred.
  - Isolated features.
  - 28 µm depth maximum at the center.
  - Slightly spherical.
  - 2-3 mm diameter.
- Equivalent to 0.34 mm/yr.



Summary of Coupon Localized Corrosion



Different forms of corrosion occurred in different phases.

Corrosion Coupon Localised Corrosion Rates

Test	**Vapour (mm/yr)**	**Water Line (mm/yr)**	**Submerged (mm/yr)**
Autoclave Test	0.24	0.96	0.34
Pipe Section Test	0.11	0.25	0.08

- In summary the ***autoclave test*** was more aggressive than the ***pipe section test***:
  - For submerged / water line areas most likely due to different surface area / volume ratio (resulting in rapid Fe saturation).
  - For vapour space, possible differences in condensation rates on crown of pipe / autoclave may also have contributed.
  - Both test set-ups (to simulate shut-in conditions) with relatively large volume of water, will also have impacted partitioning of acidic gases between liquid & gas phases.

Localised corrosion / stress cracking of Stainless Steels & Corrosion Resistant Alloys in CCUS

Where wet CO_2 is unavoidable, there is the option to use SS/CRAs. However, dependent on the conditions these can also be attacked, resulting in localised corrosion and/or stress corrosion cracking.

Recent published work shows that:

- Dense phase CO_2, with water, chlorides, and oxygen leads to localised corrosion of S13Cr & 25Cr SDSS [10].
- When considering other contaminates the condition becomes more complex [11] which shows that for DSS & SDSS
  - Addition of SO_2 did not increase corrosion rates of DSS and SDSS
  - Addition of NO_2 can induce crevice corrosion of DSS and SDSS but the mechanism is not well understood
  - Addition of O_2 in the presence of NO_2 enhanced crevice corrosion of both DSS and SDSS, and increased pitting susceptibility of DSS
  - Addition of SO_2 in the presence of NO_2 can reduce crevice corrosion of DSS and SDSS because the level of HNO_3 is reduced the chemical reaction of H_2SO_4 formation
  - High salinity can reduce pH causing localised pitting corrosion to increase.

[10] Kanki et al, paper 00004 AMPP Corrosion 2025, Nashville, TN, Apr-2025

[11 Wang et al, paper 00068 AMPP Corrosion 2025, Nashville, TN, Apr-2025

Non-Metallic Materials

An area often overlooked in pressure system design is the performance of non-metallic materials (used as seals and as piping) and their durability under CCUS conditions.

- Our own work (unpublished) some time ago showed that:
  - Most high-grade Thermoplastics (such as PTFE, PEEK, etc) and some elastomers (such as Viton™) had good durability in supercritical CO_2.
  - Whilst other Thermoplastics (such as nylon) and elastomers (including silicon rubber and natural rubber) can degrade in dense phase / supercritical CO_2.
- Recent published work [14] has shown that:
  - Thermoplastics showed minimal damage from scCO_2 exposures compared to elastomers
  - Elastomers showed internal cracks, surface texturization, structural changes, compression set changes
  - Increasing pressures in combination with long times of exposure accelerated damage in even robust polymers
  - Increasing number of temperature cycles showed varying levels of damage in polymers
  - Physical effects seen in the form of cracks inside the polymer and surface texturization
- Rapid Decompression can also lead to failures of non-metallics
- However, impact of contaminates (SO_X, NO_X, HC, etc.) on non-metallic durability have not been addressed at this time.

[14] Antoun & Menon, *Metallic and Non Metallic Material Compatibility in Super Critical CO_2 Environments*, presentation at *Roadmap for CO_2 Transport Fundamental Research Workshop* Columbus, Ohio Feb-2023

Corrosion Modelling for CCUS

Over the past 40+ years, corrosion modelling for predicting corrosion rates in sweet & sour conditions due to combined effect of CO_2 & H_2S has become the norm.

Typically, the objective is to determine the natural (non-mitigated) corrosion rate for carbon steel, and from that the corrosion allowance & corrosion inhibition requirements to ensure system integrity over the life of the facility can be achieved, or (if not) whether CRAs should be used.

Historically majority CO_2 / H_2S corrosion models used are ***empirical models*** based on multi-regression statistical analysis of extensive experimental data.

Consequently, whilst they can be considered as reasonably actuate (typically better than ±20%) when considering conditions that involve ***interpolation*** from within the experimental data range, they are less accurate when ***extrapolated*** to conditions that are outside the original data set(s).

The alternative are ***mechanistic*** (or ***fundamental***) ***models,*** applying first principal considerations, based on electrochemistry and equations of state, which can (theoretically) be applied across all conditions and all combinations of components.

Corrosion Modelling for CCUS Empirical Models

Most empirical models are based on the original work by de Waard & Milliams and IFE (Norway) aimed at predicting oil & gas production corrosion rates for carbon steel initially only for sweet (CO_2 only) conditions. Later these were extended to include effects of H_2S, acetates, flow rates, oil filming, etc.

Allowable ranges for CO_2, H_2S and temp in the most popular empirical models are:

Model	Max ppCO2	Max ppH_2S	Max temperature
NORSOK M506 (rev 3)	10 bar	na	150°C
BP Cassandra (Alloy Select™) (note A)	1 bar	na	80°C
ECE5.9™ & Larkton CM™ (note B)	20 bar	15 bar	120°C

None of the above limits are applicable for dense phase or supercritical CO_2 operations and (except for H_2S) don't consider impact of any possible impurities that could occur from industrial sources of CO_2 for sequestration.

(A) BP Cassandra is no longer supported by BP but has been incorporated into AlloySelect™ but do not clearly define a practical CO_2 limit.

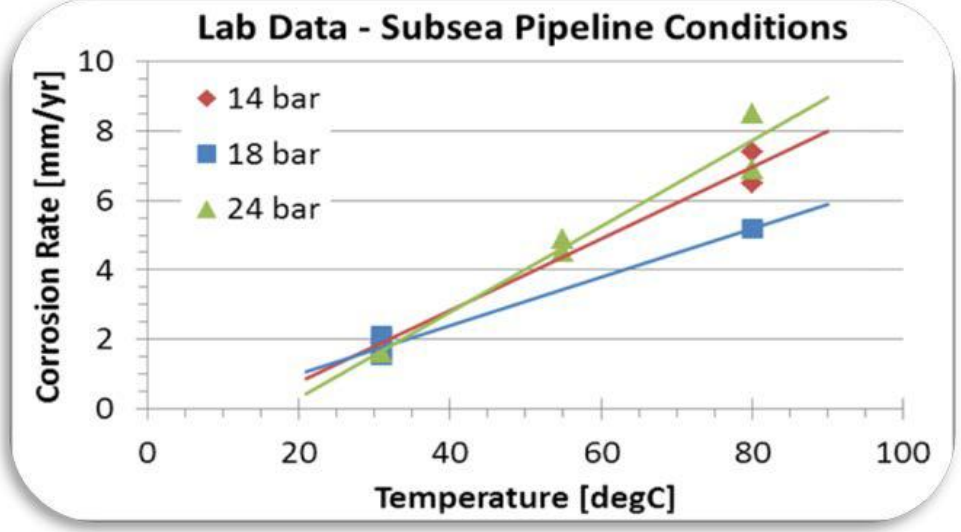
(B) Both ECE™ & LarktonCM™ will accept higher ppCO2/ppH2S values, but both provide an advisory that the accuracy of any prediction is limited above these limits. For ppCO_2 > 60 bar or ppH_2S > 15 bar they are only for indicting trend / order of magnitude.

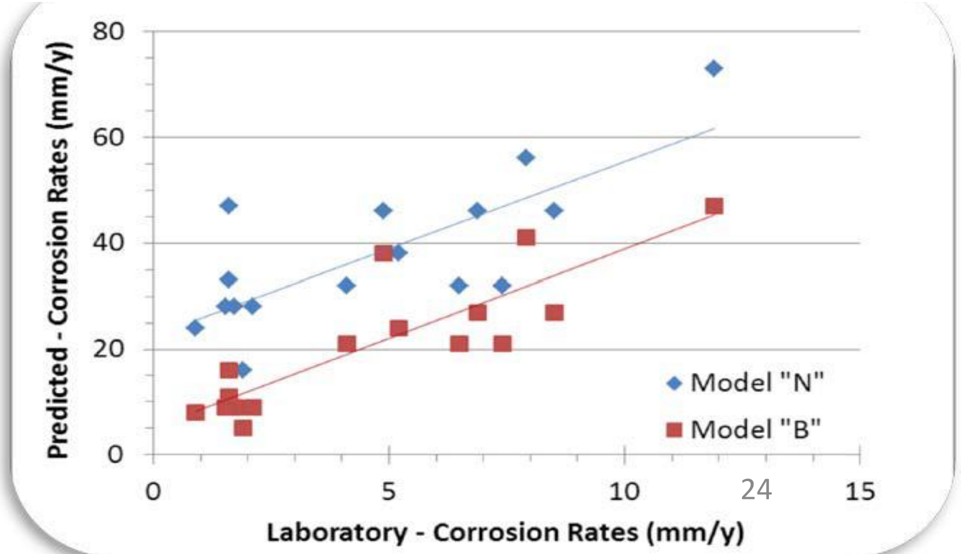
Model Correction for CCUS conditions

Experience has shown that the current empirical models give very conservative (unrealistically high) corrosion rates when used outside their normal range.

In one of our previous projects [15] looking at issues associated with CO_2 EOR, predicted rates (Norsok M506 & BP Cassandra models) were compared to laboratory data.

- Test conditions were:
  - Temp : 31 to 100°C
  - $ppCO_2$: 7 to 80 bar
  - Gas (2 mixtures) : 100% CO_2 and 0.5% H_2S / bal CO_2
  - Test Solution : Simulated produced water & Condensed water
- Using the comparison data, the predicted corrosion rates were significantly higher than lab data, to provide a correction factor:
  - Norsok M506 expected rate ≈ 0.125 predicted rate
  - BP Cassandra. Expected rate ≈ 0.25 predicted rate.
- Using the correction factor, we were then able to provide an estimated expected rate across the facility, covering a wider range of conditions that could be realistically address in any laboratory program.





[15] Binahabet, John, et al; NACE Corrosion 2016, paper 7649, Vancouver, BC, Mar-2016

Corrosion Modelling for CCUS Empirical Models - developments

Several organisations are now trying to expand the use of existing empirical models to cover the wider issues in CCUS systems. These include:

- Determination of phase behaviour in relation to conditions leading to formation of a (corrosive) free water phase due to the presence / interaction of:
  - gas composition including H_2O, H_2S, O_2, SO_X, NO_X, HC etc, and
  - temperature & pressure
- Conditions lead to formation / drop-out of acids (such as H_2SO_4, HNO_3, etc) and their subsequent effect on pH, scale stability and carbon steel corrosion rate.

The ability to identify conditions which will lead to formation of a water phase are covered by various software packages, based on various options with respect to equations of state either a separate packages (such as MultiFlash™, MultiScale™ & OLI *CO_2 Transportation App*™) or included within corrosion programs (such as GUTS in ECE6.0™)

However, at this time, there are *(as far as we are aware)* no working empirical models covering the effects of the impurities on the carbon steel corrosion rate.

Corrosion Modelling for CCUS Mechanistic / Fundamental models

There are several mechanistic / fundamental models available in relation to CO_2 / H_2S corrosion prediction for oil & gas production & transport, including *FREECORP*™ & *MULTICORP*™ (developed by University of Ohio). However, all these have operating limits below that required for CCUS operation.

At this time the OLI Studio: *Corrosion Analyzer*™ [16] fundamental model covers the conditions and composition relevant to CCUS, as well as the PACE CCS™ corrosion model [17] Aalborg University are also developing a fundamental model [18]..

Another approach that is being considered by U of Leeds [19], relates to developments in *Artificial Intelligence* (AI), with the application of ***Machine Learning Models*** being developed to cover the complex / wide ranging issues in CCUS facilities.

However, for Machine Leaning Models to be developed successfully they will need a lot of ***reliable*** data to analyse. Hence the need for continuing development in laboratory test programs in this area!

[16] https://www.olisystems.com/software/oli-studio/oli-studio-corrosion-analyzer/
[17] https://paceccs.com/corrosion/
[18] Ostadi et al, AIChE Annual Meeting, Boston, MA, Nov 2025
[19] Proudlove et al, Paper 00161, AMPP Corrosion 2025

Summary - *What we know* ☑ / *What we don't know* ☒:

- Presence of Free water is critical in relation to corrosion in CCUS systems, which is dependent on the temperature, pressure and fluid composition, and can be determined from existing models / Equations of State. ☑
- A number of different impurities (such as H_2S, O_2, SO_X, NO_X, CO, and others) will increase the overall corrosivity. However, because these are typically present in trace quantities (< 100 ppmv) it is difficult to: ☑
  - Carry out reliable laboratory testing ☑ ☒
  - Reliability measure their concentration in CO_2 streams
- Impact of process upsets (shutdowns / start ups) on overall carbon steel corrosion rates not fully established. ☑ ☒
- SS/CRAs generally provide good corrosion resistance, but some alloys can suffer from localised corrosion / stress corrosion cracking dependent on conditions and impurities. ☑ ☒

…

What we know ☑ / *What we don't know* ☒ : (continued)

- Whilst Thermoplastics (such as PTFE, PEEK, etc.) and some elastomers (such as Viton™) are fully compatible with CCUS conditions, other materials show varying degrees of degradation. With the effect of impurities not fully quantified. ☑ ☒
- Computer models (based on Equations of State) are available to predict formation of free water phase in CCUS operations (including allowing for effects of impurities). ☑
- At this time there are no ***empirical*** corrosion models that have been validated for predicting corrosion rates of carbon steel in CCUS operations. ☑ ☒
- At this time there are a limited number of ***mechanistic / fundamental*** corrosion models that have been used for CCUS systems. ☑
- Other models are being developed (including the use of ***Machine Learning AI systems***) but are still some way from being fully validated. ☑ ☒