Appendix 1

List of participants

Participants EFC WP15 meeting 3th May 2018 Dalmine (Italy)

NAME	SURNAME	COMPANY	COUNTRY
Al Musharfy	Mohamed	ADNOC Refining Research Center	UNITED ARAB EMIRATES
Arzuffi	Mirko	Amec Foster Wheeler	ITALY
Bignardi	Riccardo	Rina Consulting	ITALY
Bour Beucler	Valerie	Nalco Champion	FRANCE
Claesen	Chris J	Nalco Champion	BELGIUM
Coppola	Tommanso	Rina Consulting	ITALY
Corradini	Raffaele	Techint Engineering	ITALY
Cozza	Ricardo	Saras	ITALY
De Landtsheer	Gino	Borealis	BELGIUM
de Marco	Marco	Istituto Italiano della Saldatura	ITALY
Divido	Luigi	Rina Consulting	ITALY
Escorza	Erick	Tenaris Dalmine	ITALY
Farina	Carlo	CEFIT Corrosion Consultant	ITALY
Fersini	Maurizio	Allied Fittings	ITALY
Fullin	Luna	Tenaris Dalmine	ITALY
Gabetta	Giovanna	Eni	ITALY
Ghidini	Andrea	Sices Group	ITALY
Kus	Slawomir	Honeywell	UK
Lombardo	Paolo	Isab	ITALY
Lucci	Antonio	Rina Consulting	ITALY
Madeddu	Enrico	Sartec	ITALY
Manganini	Diego	Sices Group	ITALY
Marcolin	Giacomo	Tenaris Dalmine	ITALY
Merlini	Paolo	Tenaris Dalmine	ITALY
Millefanti	Mirko	Sices Group	ITALY
Monnot	Martin	Industeel	FRANCE
Poldi	Matteo	Eni	ITALY
Ropital	François	IFP Energies nouvelles	FRANCE
Russo	Emanuele	Eni R&M	ITALY
Sentjens	Johan	Temati	NETHERLANDS
Smith	Ali	Rina Consulting	ITALY
Spaghetti	Alessandra	Sandvik	ITALY
Suardi	Edoardo	Sarlux	ITALY
Suleiman	Mabruk	ADNOC Refining Research Center	UNITED ARAB EMIRATES
Tabaud	Frederic	BP RTE	NETHERLANDS
Tarantino	Sebastian	Sitech	NETHERLANDS
Torella	Raffaele	Rina Consulting	ITALY
Van Rodijnen	Fred	Oerlikon metco	GERMANY
van Roij	Johan	Shell Global Solutions International B.V.	NETHERLANDS
White	Calum	KAEFER Isoliertechnik GmbH & Co. KG	GERMANY

Appendix 2

EFC WP15 Activities

(F. Ropital)

Presentation of the activities of WP15

European Federation of Corrosion (EFC)

- Federation of 29 National Associations
- 21 Working Parties (WP) and 1 Task Force
- Annual Corrosion congress « Eurocorr »
- Thematic workshops and symposiums
- Working Party meetings (for WP15 twice a year)
- Publications

for more information http://www.efcweb.org

EFC Working Party 15 « Corrosion in Refinery » Activities

http://www.efcweb.org/Working+Parties-p-104085/WP%2B15-p-104111.html

Chairman: Francois Ropital   Deputy Chairman: Johan Van Roij

Information Exchange – Forum for Technology
Sharing of refinery materials /corrosion experiences by operating company representatives (ie corrosion atlas).
Sharing materials/ corrosion/ protection/ monitoring information by providers

Eurocorr Conferences : organization of refinery session and joint session with other WPs (2018 Krakow-Poland, 2019 Seville-Spain, 2020 Brussels-Belgium)

WP Meetings
One WP 15 working party meeting in Spring,
One meeting at Eurocorr in September in conjunction with the conference,

Publications - Guidelines

Education – qualification – certification
List of "corrosion refinery" related courses on EFC website ?
Proposal of courses within Eurocorr ?

EFC Working Party 15 « Corrosion in Refinery »

List of the WP15 spring meetings :

10 April 2003	Pernis - NL (Shell)
8-9 March 2004	Milan -Italy (ENI)
17-18 March 2005	Trondheim- Norway (Statoil)
31 March 2006	Porto Maghera - Italy (ENI)
26 April 2007	Paris - France (Total)
15 April 2008	Leiden -NL (Nalco)
23 April 2009	Vienna - Austria (Borealis)
22 June 2010	Budapest - Hungary (MOL)
14 April 2011	Paris - France (EFC Head offices)
26 April 2012	Amsterdam - NL (Shell)
9 April 2013	Paris - France (Total)
8 April 2014	Mechelen - Belgium (Borealis)
14 April 2015	Leiden -NL (Nalco)
26 April 2016	Paris - France (Total)
13 April 2017	Frankfurt - Germany (EFC Head offices)
3 May 2018	Dalmine- Italy (Tenaris)

Publications from WP15

• EFC Guideline n°40 « Prevention of corrosion by cooling waters » available from http://www.oxbowbooks.com/oxbow/working-party-report-on-control-of-corrosion-in-cooling-waters.html

•EFC Guideline n° 55 Corrosion Under Insulation *New edition nov. 2015*
http://store.elsevier.com/product.jsp?isbn=9780081007143&pagename=search

•EFC Guideline n° 46 on corrosion in amine units *A revision is in progress by a task force*

•Future publications – task forces : suggestions ?

- best practice guideline on corrosion in sea water cooling systems (joint document WP9 Marine Corrosion and WP15)
- best practice guideline to avoid and characterize stress relaxation cracking ?

EFC EUROPEAN FEDERATION OF CORROSION

WP15 Corrosion Atlas Web page

https://www.efcweb.org/Working+Parties/WP+Corrosion+in+the+Refinery+Industry/WP+15+Refinery+Corrosion+Atlas.html

EFC EUROPEAN FEDERATION OF CORROSION

Eurocorr 2018 Congress

Krakow Poland 9-13 September 2018

Authors will be informed by the end of April

Refinery corrosion session on Monday 10th September all day

Annual WP15 working party meeting during Eurocorr on Tuesday 11th September – to be confirmed -

https://eurocorr2018.org/en

Information :
Future conferences related to refinery corrosion

9-13 September 2018
EUROCORR 2018 Krakow Poland

24-29 March 2019
CORROSION 2019 NACE Conf Nashville Tennessee

8-13 September 2019
EUROCORR 2019 Seville Spain

6-10 September 2020
EUROCORR 2020 Brussels Belgium

Look at the Website: www.efcweb.org/Events

EFC Working Party 15 « Corrosion in Refinery » Activities
Who is an EFC member

To be an EFC member you (individually or your company, university) has to be member of one of 29 national EFC "member societies". Your company or university can now also an affiliate member.

For example:
in Norway: Norsk Korrojonstekniske Forening
in France: Cefracor
in Germany: Dechema or GfKORR
in UK: Institute of Corrosion or IOM or NACE Europe
in The Netherlands: Bond voor Materialenkennis
in Poland: Polish Corrosion Society
....
You will find all these information on www.efcweb.org or in the EFC Newsletter

Benefits to be an EFC member:
- 20% discount on EFC Publications and NACE Publications
- reduction at the Eurocorr conference
- Access the new EFC web restricted pages (papers of the previous Eurocorr Conference) via your national corrosion society web pages

Appendix 3

THOR™ 115 – New ferritic steel with improved oxidation and sulfidation resistance

(L. Fullin)

EFC – WP15 Spring Meeting 2018

Dalmine – May 3rd, 2018

Thor™ 115

Tenaris High Oxidation Resistance Steel

L. Fullin – Product Engineer

G. Marcolin – Product Manager

Agenda

Introduction

Metallurgy and properties

Special tests

- Steam Oxidation
- Sulfidation and NAC
- HGO Hydrotreating Pilot Plant Chlorides

Manufacturing experience

Conclusions

Agenda

Introduction

Metallurgy and properties

Special tests

- Steam Oxidation
- Sulfidation and NAC
- HGO Hydrotreating Pilot Plant
- Chlorides

Manufacturing experience

Conclusions

Introduction – New Tenaris Grade

Agenda

Introduction

Metallurgy and properties

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Manufacturing experience

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Metallurgy and Properties

Design

Tenaris worked on the development and qualification of a new martensitic steel for high temperature applications with enhanced oxidation resistance.

- Improved steam oxidation resistance vs. 9Cr grades
- Creep properties better than grade 91
- Friendly in manufacturing and welding

Composition

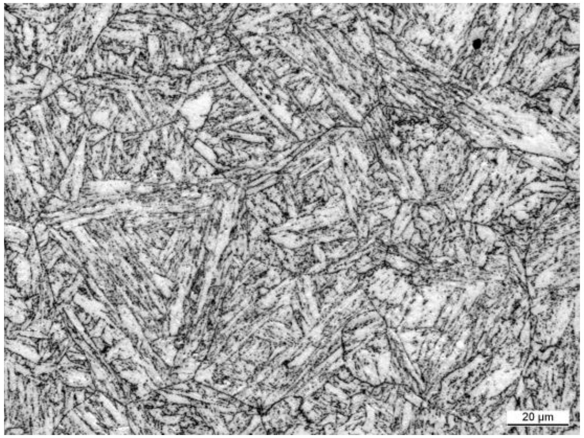
C	Mn	Si	Cr	Ni	Cu	Mo	Al	V	Nb	N
0.1	0.4	0.4	11.0	< 0.2	< 0.15	0.5	< 0.02	0.2	0.04	0.05

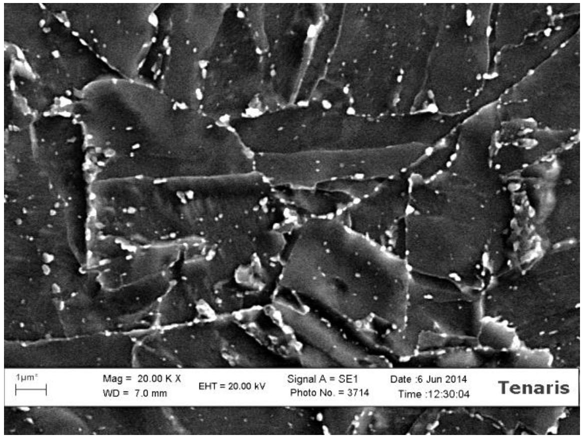
Metallurgy and Properties

Microstructure

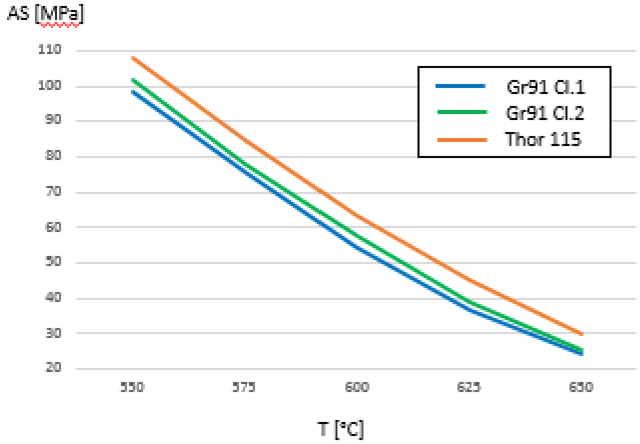
Thor™ 115 microstructure consists of tempered martensite.

Cr-Ni balance limit enforced to prevent formation of δ ferrite.





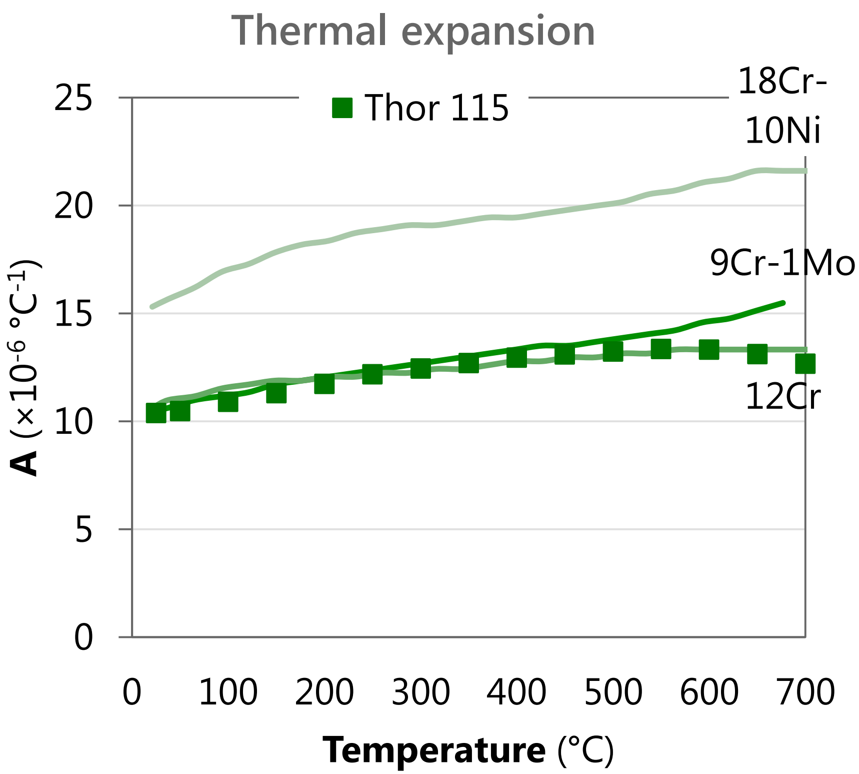
(MPa) \ (°C)	550	575	600	625	650
New Gr.91 Cl. 1	98.5	75.5	54.3	36.8	24.0
New Gr.91 Cl. 2	102	78.2	57.6	39.2	25.1
Thor 115	108	85.0	63.3	45.3	29.8

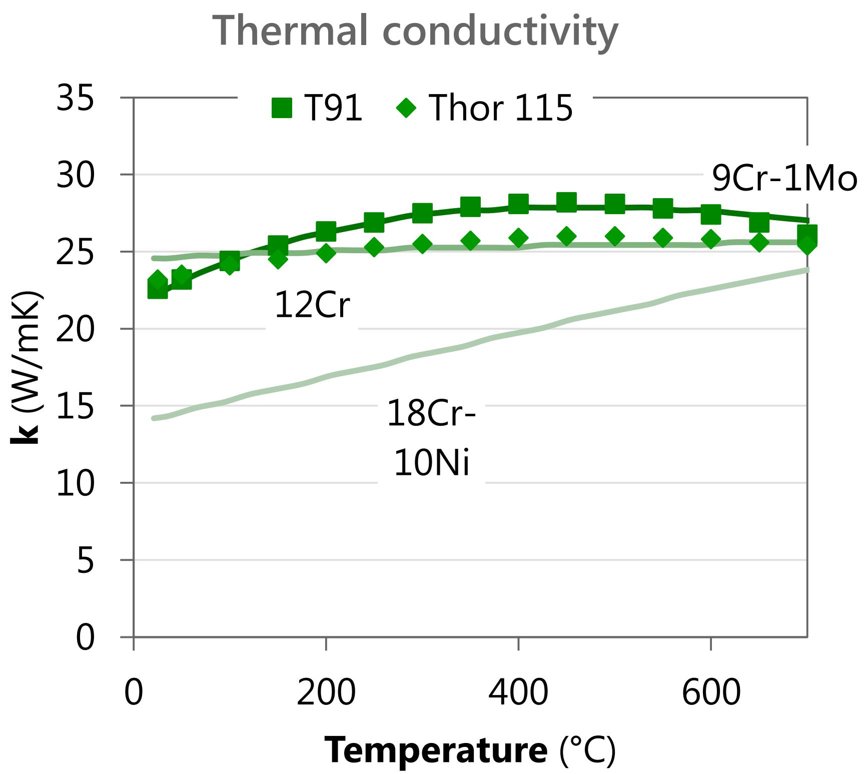


Metallurgy and Properties

Physical properties

As a ferritic steel, Thor presents smaller thermal expansion and better thermal conductivity with respect to austenitic grades.

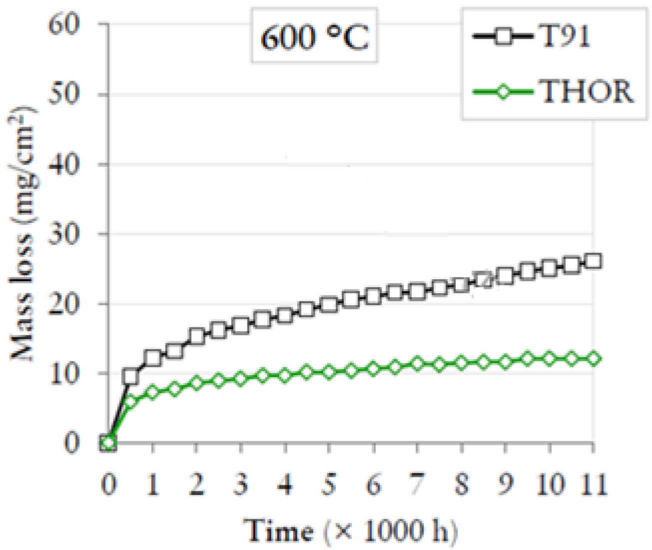




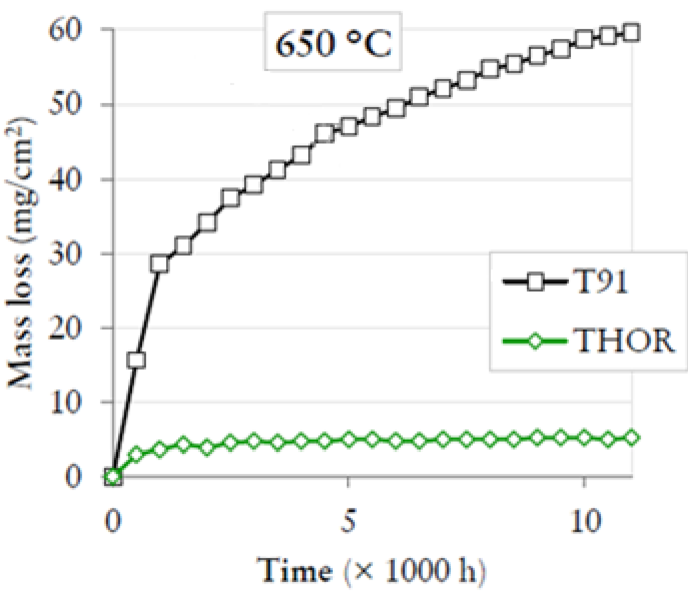
Agenda

Steam Oxidation

- Steam oxidation testing performed by **Oak Ridge National Laboratory**
- Furnaces holding specimens (600, 625, 650 °C) fluxed with steam from ultra-high purity water.
- Testing duration 11,000 h (about 460 days)
- Specimens removed from furnaces every 500 h for the measurement of mass loss as a function of time.



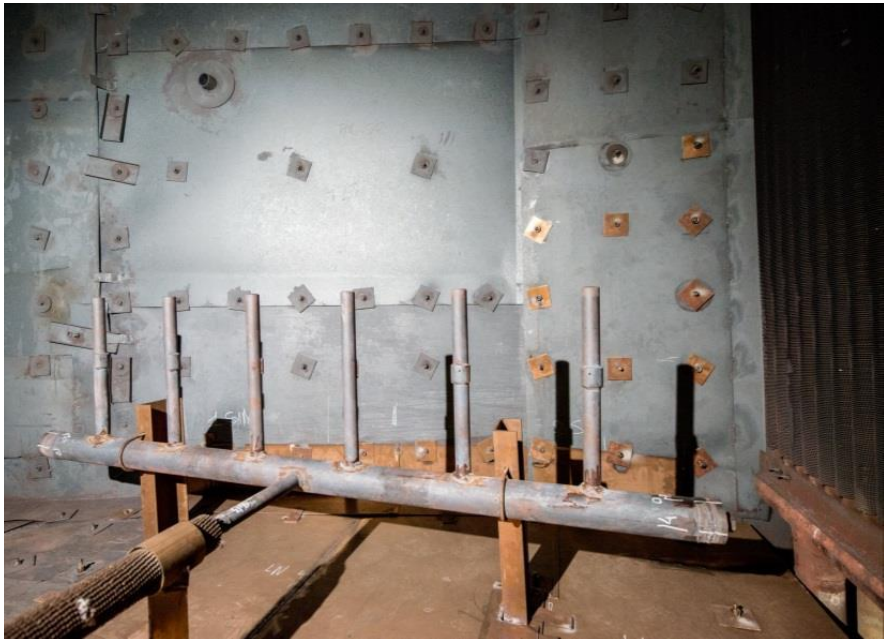
Rate of oxidation in Thor is similar between 600 and 650 °C, thanks to the higher amount of available Cr for diffusion to the surface, forming a compact protective oxide (spinel) layer at higher temperature.



Steam Oxidation - Field experience

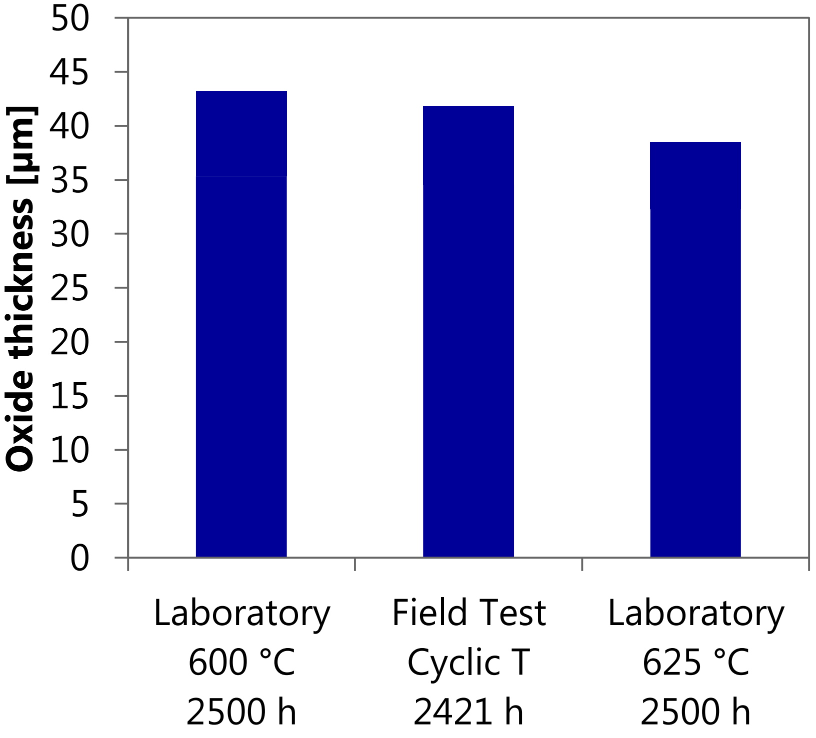
HRSG test loop

Installed and running since May 2015.



Superheater steam is extracted from an existing vent and reheated inside a Thor circuit up to 615 °C.

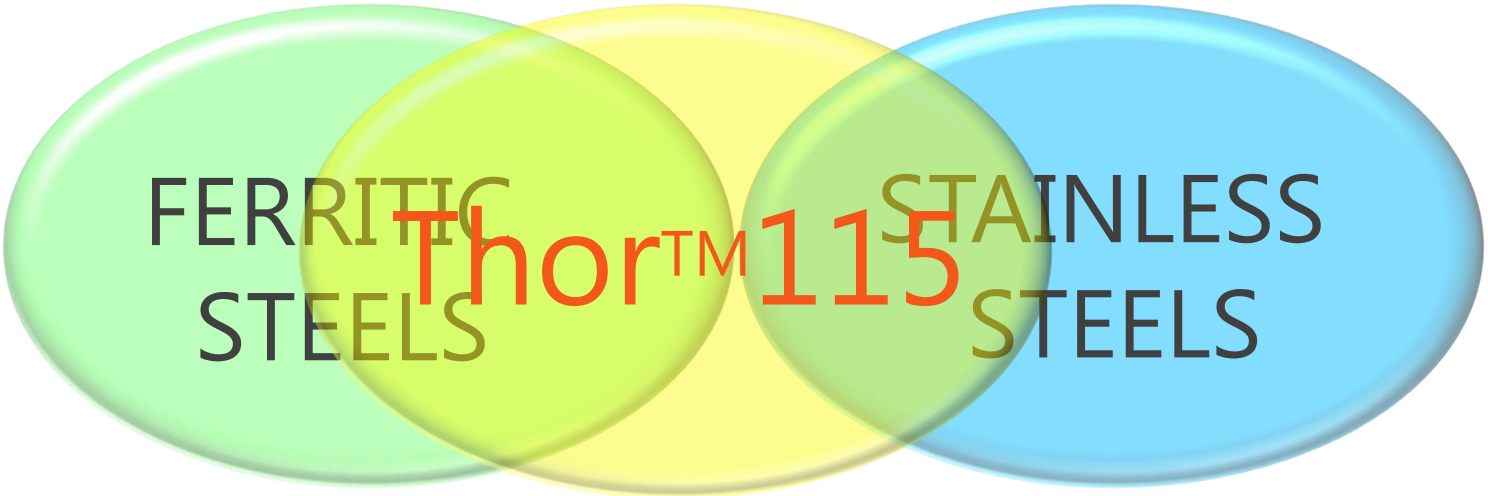
Scale thickness at the inner tube surface after **2,421 h**.



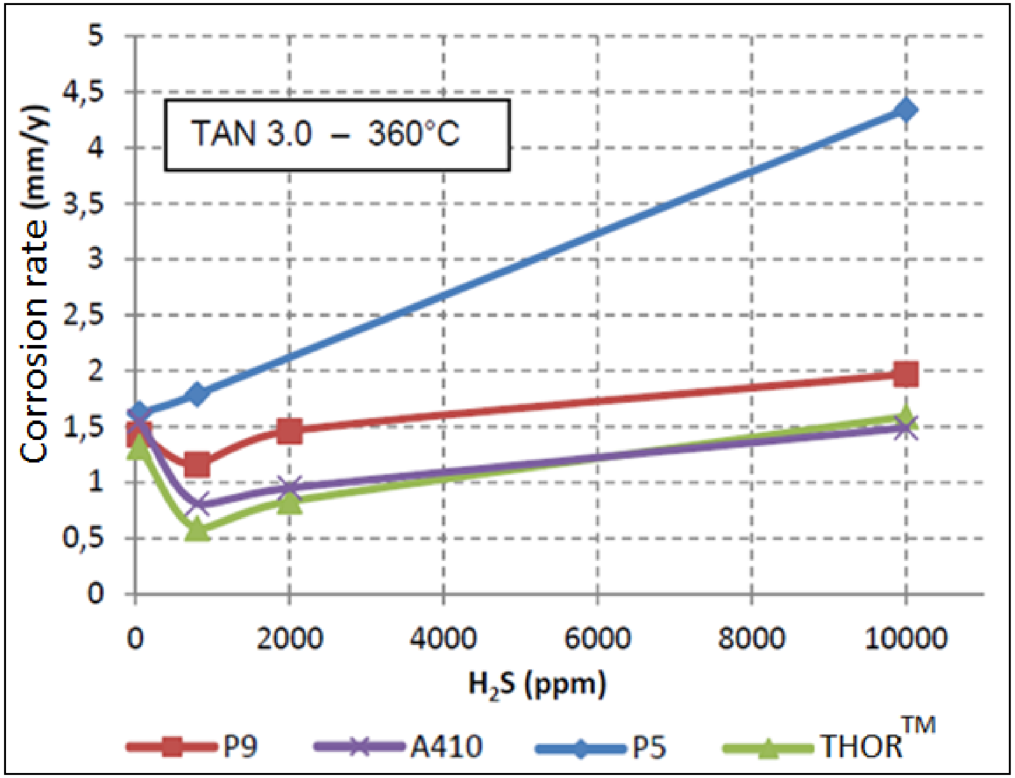
THOR™115 in Downstream

Chemistry identified as suitable for Refining corrosive environment

- Chemical composition in the middle of Ferritc and Stainless families
- Identification of fields of application of those materials
- Study of THOR behavior to understand strengths and weaknesses coming from Ferritic Steels and Stainless Steels



Special tests: Sulfidation and NAC

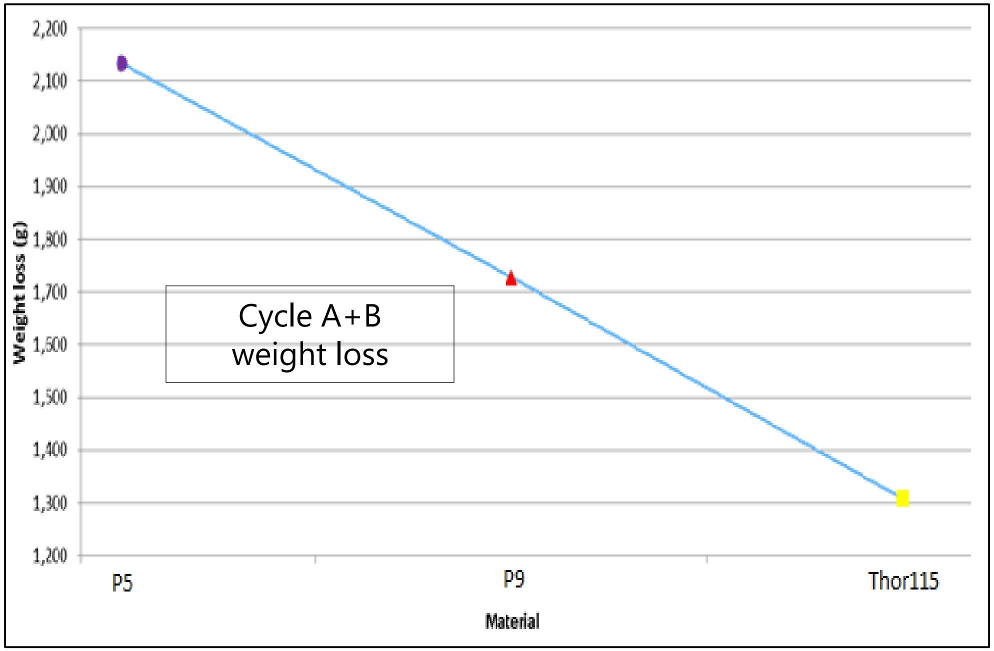


- Pilot Plant in VeneziaTecnologie
- No TAN decrease for degradation
- Comparative tests
- Tests in naphthenic and sulphidic environment
- Expected trends confirmed after weight loss analysis at different H_2S contents

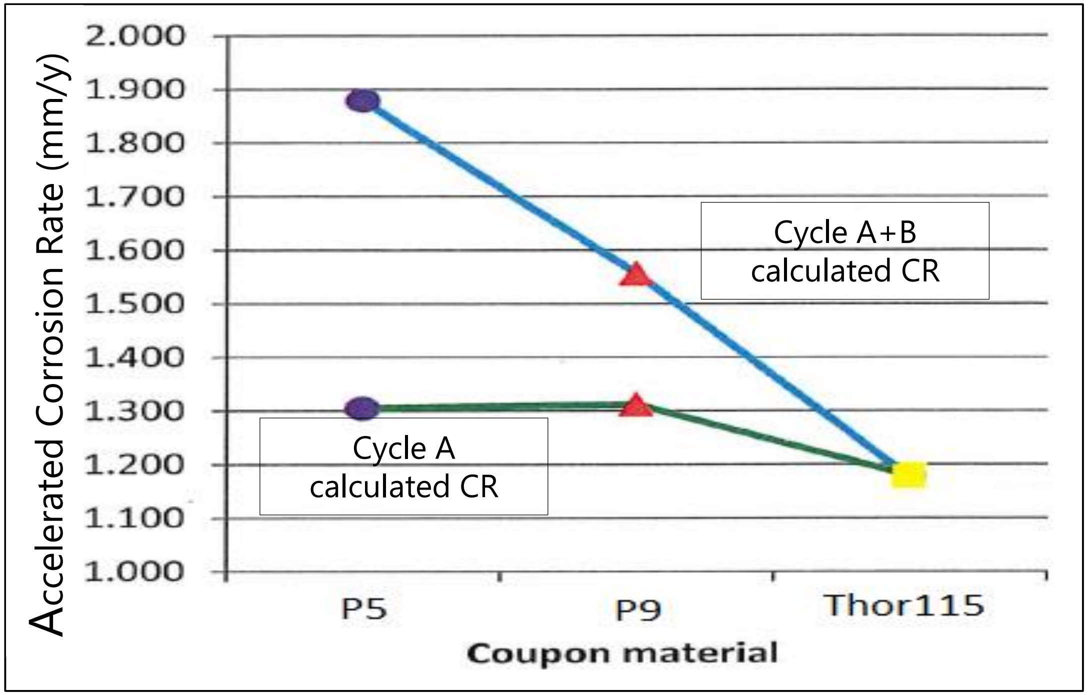
Special tests: HGO hydrotreating pilot plant

- Tests performed at ARRC in Abu Dhabi
- HGO Hydrotreating
- 2 cycles, 1 month each
  - cycle A at 390°C
  - cycle B at 420°C
- Comparative tests and temperatures to stress corrosion kinetics:
  - First cycle stimulating FeS layer formation
  - Second cycle boosting T

- Lower weight loss of Thor 115



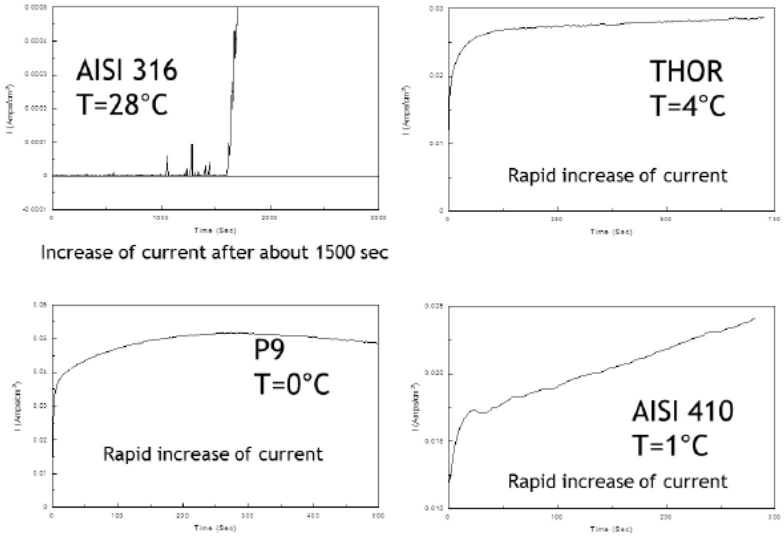
Special tests: HGO hydrotreating pilot plant



- Calculated corrosion rate unchanged between first cycle and after the 2 cycles
- Higher stability of protective layer

Special Tests: Chlorides

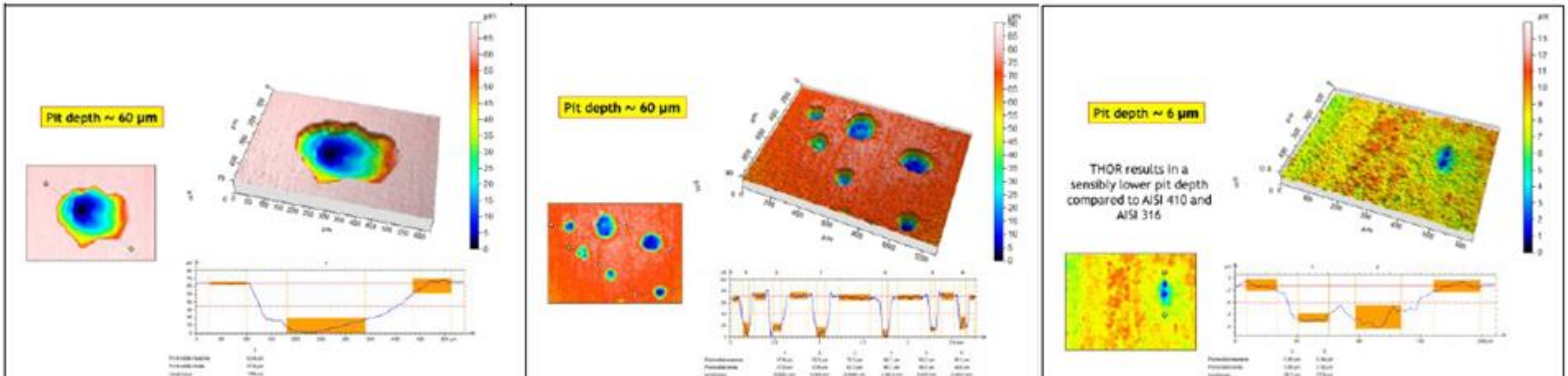
- Test Parameters as per ASTM G150



Tests carried out in CSM laboratories.
Pitting morphology observed on THOR and SS:

- Diffuse shallow pits on THOR surface (depth ≈ 6 μm)
- Deep localized pits on SS (depth ≈ 60 μm)

Possible advantage in critical-defect failure modes



AISI 316	AISI 410	THOR
Pit depth ≅ 60 μm	Pit depth ≅ 60 μm	Pit depth ≅ 6 μm

Agenda

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Pipes and Tubes

Trial heats successfully cast

Seamless pipes and tubes rolled covering Grade 91 feasibility

Main applications

- *Boiler tubes (HRSG, heat exchangers, ...)*
- *Steam lines*
- *Furnace pipes (cracking furnaces, reformer interheater tubes, ...)*
- *Process Pipes (Vacuum Circuit, Hydroprocessing, Visbreaking, ...)*

Thor™115: Manufacturing experience

Piping component	Manufacturer
Tubes NPS 1 to 4 in	Tenaris Silcotub
Pipes NPS 6 to 24 in	Tenaris Dalmine
Forged Flanges	Officine Melesi
Forged and Bored Pipes	Tenaris Dalmine / Simas
Fittings	Allied Fittings

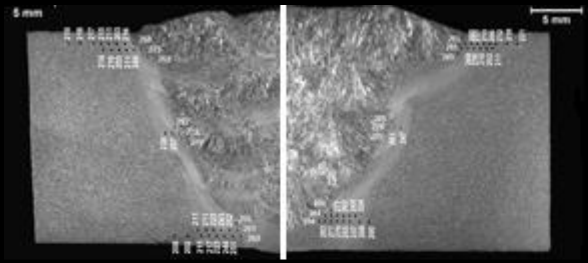
- Process parameters equal to the ones used for grade 91
- Full mechanical characterization, with satisfactory results

Welding

Trials by GE power (Chattanooga)

Allowable stress is similar to grade 91, and tempering heat treatment temperatures overlap. Ni-based filler may be used where oxidation is an issue.

- Thor-Thor joints with 9Cr filler
- Thor-Thor joints with Ni-alloy filler
- Dissimilar joints with ferritic and stainless steels



Agenda

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Conclusions and Developments

Thor Achievements

- **Improved steam oxidation resistance** vs. 9Cr grades
- **Creep properties** better than new grade 91 class 1 and 2
- **Microstructurally stable** (delayed formation of Zphase, no Laves phase)
- **Friendly in manufacturing** and welding
- **Sulfidation resistance** increased against P9
- **Different failure** mode in Chlorides environment vs Austenitic SS

Next steps

- Thor™115 in API 530 and API 560 for furnaces
- Test loops in refineries

Thank you

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Appendix 4

Testing of a material under HDT condition of a refinery

(M. Suleiman)

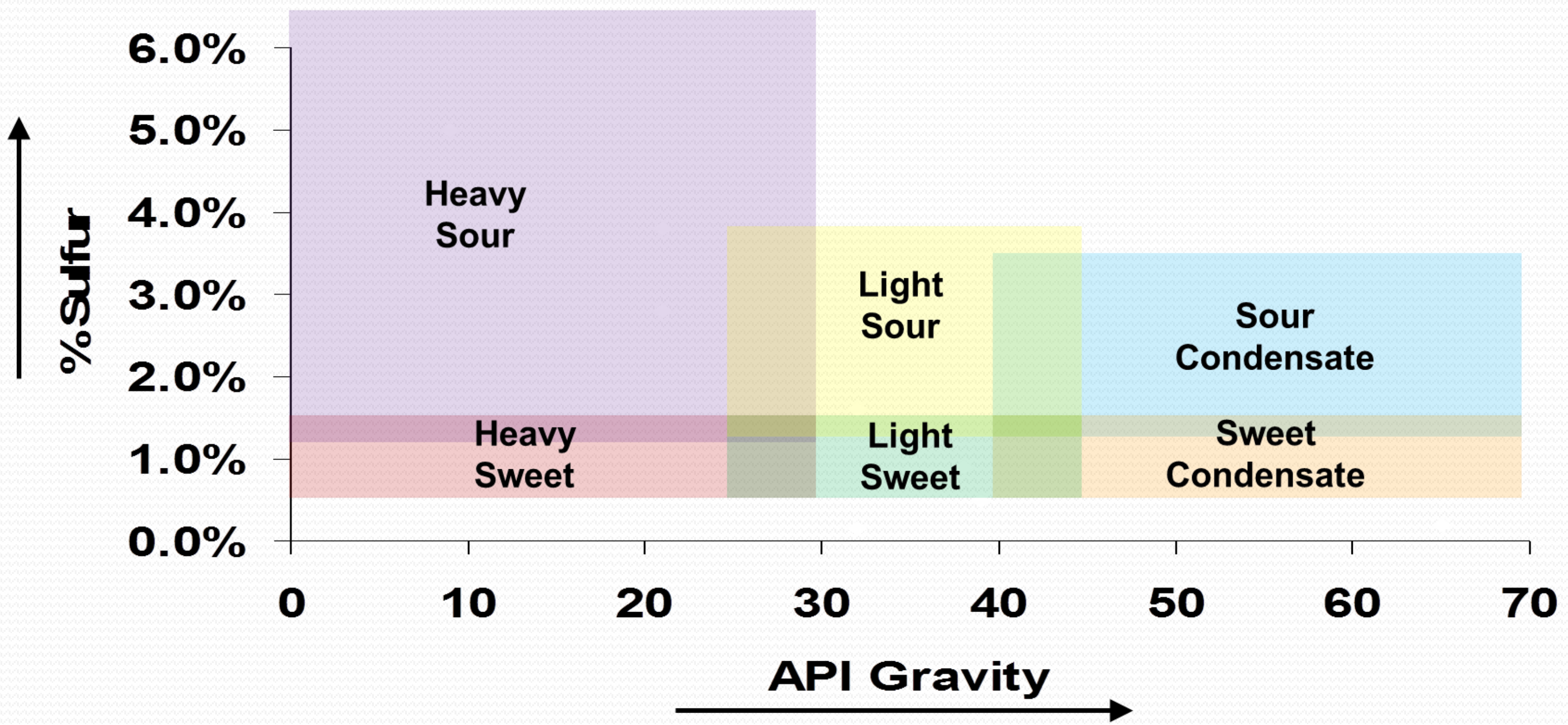
Material Corrosivity Evaluation Under Simulated Hydrotreating Condition

By: Dr Mabruk Issa Suleiman

OUTLINE

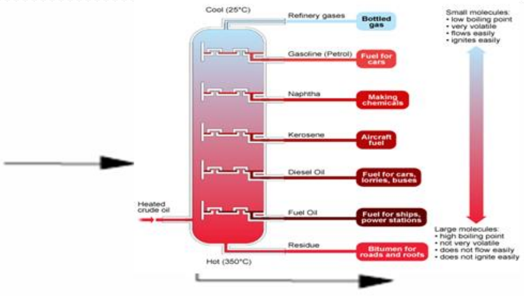
- Introduction
- Objective & Methodology
- Exposure Tests
- Test coupons prior to exposure
- Operational conditions – trends
- Test coupons after exposure
- Results & Discussion
- Summary

Crude Classification
Based on API Gravity & Sulphur



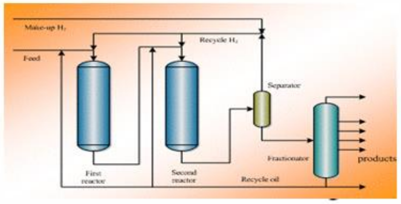
Refining

SEPARATION



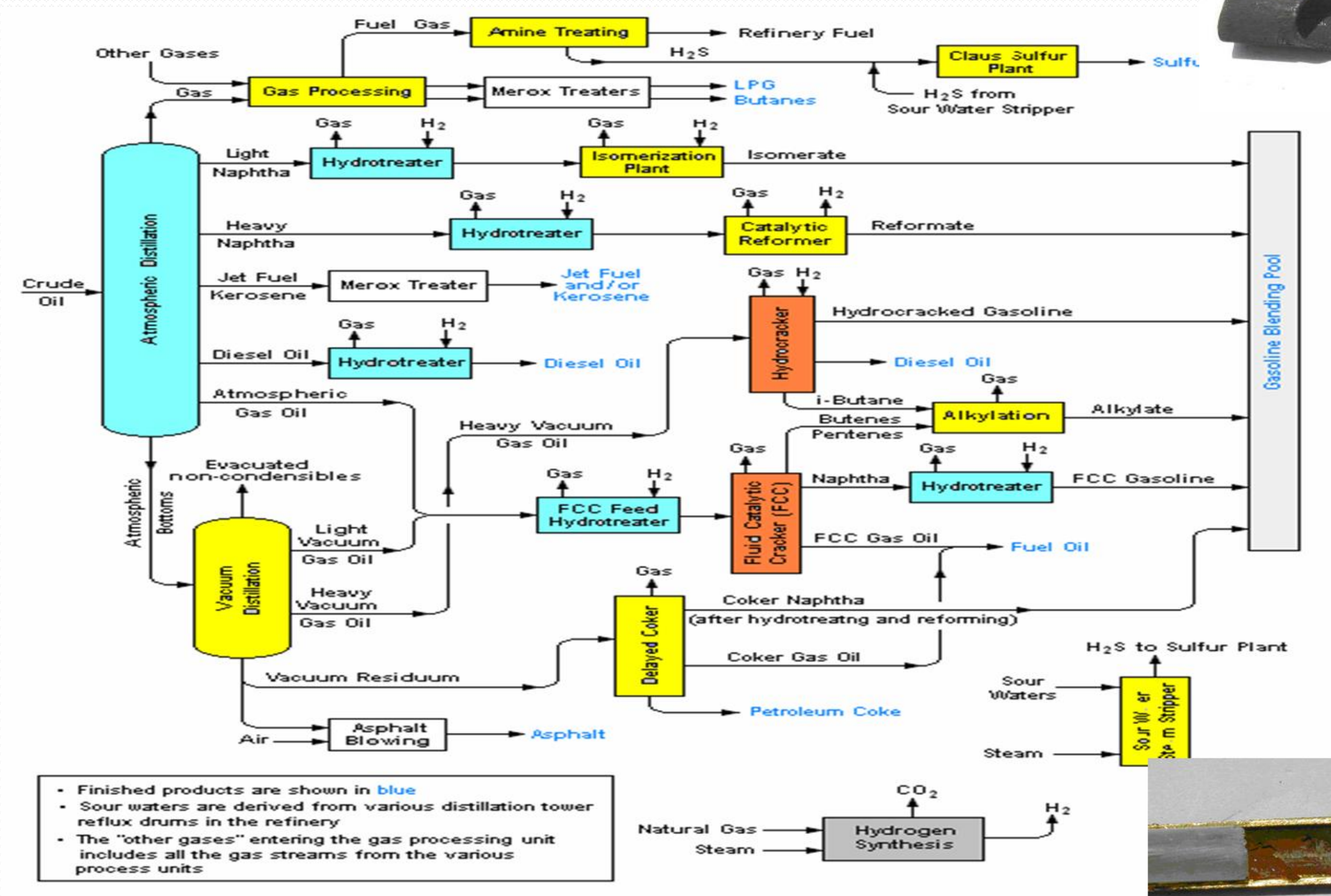
IMPROVEMENT

CONVERSION

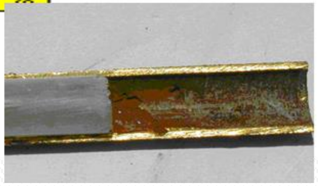


BLENDING

Process Flowchart of a Refinery



62 identified damage mechanisms



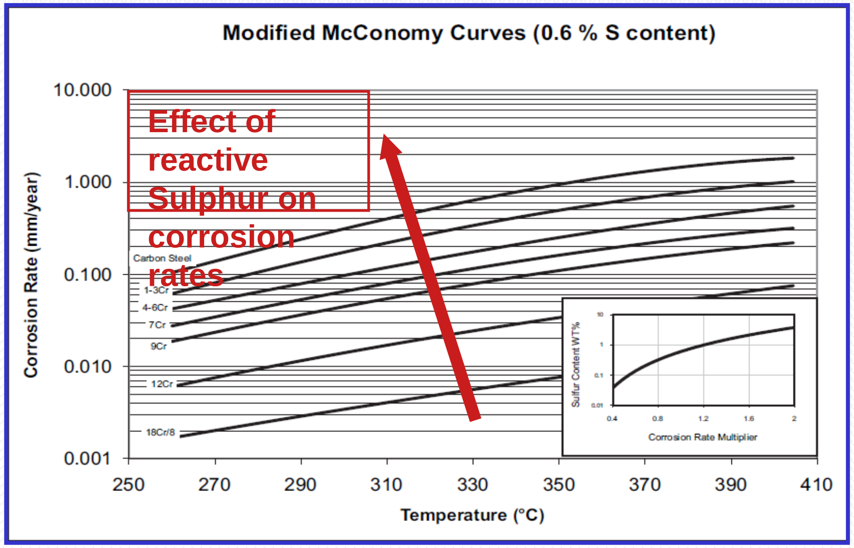
MOST COMMON MECHANISMS

S.N	DMN	Damage Mechanism	Inspection technique	Suitable material	% Location
1	1	Sulfidation	Visual, UT, and RT	5 & 9 Cr, or austenitic stainless steel depending on wt% S	9.5
2	2	Wet H2S Damage (Blistering/HIC/SOHIC/SSC	UT, DPT, MP, RT, AET	Low sulfur CS, Stress relieving	7.5
4	4	High temp H2/H2S Corrosion	UT, DPT,RT	Austenitic stainless steel	2.4
3	5	Polythionic Acid Cracking (*NACE Standard RP0170)*	UT, DPT, Metallography	Thermally stabilized 347 SS, alloy 20, alloy 625	2.9
4	6	Naphthenic Acid Corrosion	UT RT, and VI,	Austenitic stainless steel with higher Molybdenum content.	7.2
5	7	Ammonium Bisulfide Corrosion	UT ,RT IRIS, EC	300 Series SS, duplex SS, aluminum alloys and nickel base alloys	8.1
6	8	Ammonium Chloride Corrosion	RT or UT stream monitoring	Alloys 400, duplex SS, 800, and 825, Alloys 625 and C276 and titanium	4.6
7	9	HCl Corrosion	automatic ultrasonic scanning methods or profile RT	Alloy 400, titanium and some other nickel base alloys	4.3
8	10	High Temperature Hydrogen Attack	UT using a combination of velocity ratio and backscatter , &VI, metallography	To satisfy API 941 , and use of SS cladding and weld over lay.	3.7
12	20	Erosion / Erosion-Corrosion	IR UT, RT, and corrosion coupons	Higher molybdenum containing alloys	6.3
13	22	Amine Cracking	WFMT or ACFM	API RP 945, Use solid or clad stainless steel, Alloy 400 or other corrosion resistant alloys in lieu of carbon steel	6.6
14	23	Chloride Stress Corrosion Cracking	UT, DPT, EC, Metallography	Carbon steels, low alloy steels and 400 Series SS, and nickel based alloys	5.5
19	45	Amine Corrosion	UT,VT, corrosion coupons	300 , 400 series SS	4.9

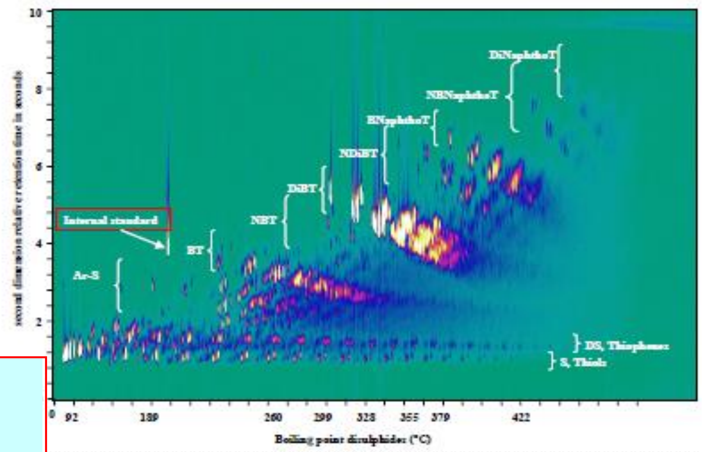
Material Selection for the Service life

Components Design life	Years
Pressure vessels, reactors, exchangers and towers	30 Years
Exchanger tube bundles	10 Years
Non-removable trays and internals	30 Years
Tanks	30 Years
Heater tubes	100,000 Hours
Compressor Cases	20 Years
Piping Process	30 Years
Piping Utilities	30 Years
Pumps	30 Years
Replaceable trim and internals for pumps	4 Years minimum

ACTIVE SULPHUR

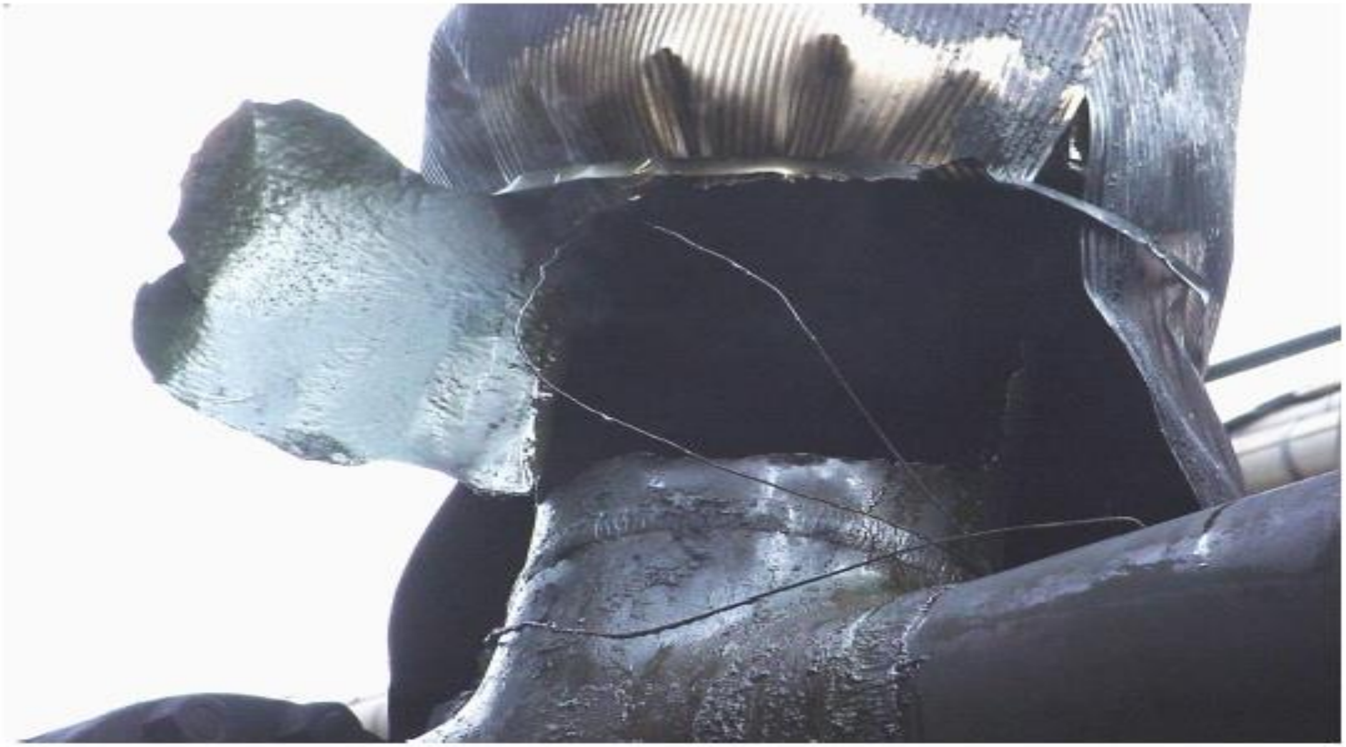


(1200 ppm) is less corrosive than the one having (590 ppm) due to the Presence of active Sulphur in several



S,Th	Sulphides, Thiols
DS, T	DS, Thiophenes
Ar-S	Aryl-sulphides
BT	Benzothiophenes
NBT	Naphtenic-Benzothiophenes
DiBT	Di-Benzothiophenes
NDiBT	Naphtenic-di-Benzothiophenes
Bnaph	Benzo-Naphthothiophenes
NBNaph	Naphthenic-Benzo-Naphthothiophenes
DiNaph	DiNaphthothiophenes

Case History

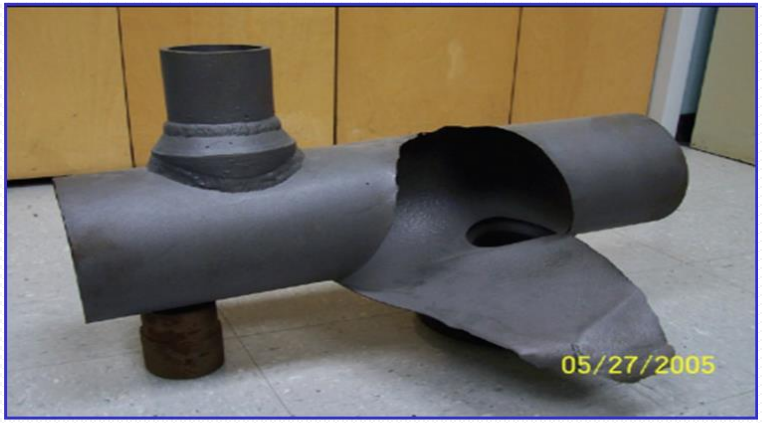


SOME EXPERIENCE WITH MERCAPTAN-SULFIDIC CORROSION

Site	Metallurgy	Feed Composition	Corrosion rate	Location
Singapore	CS A106	Laminaria and others	>1 mm/yr	CDU furnace
Canada	Carbon steel	Condensate	1.6 mm/yr	Main fractionator furnace tubing and column
UK	CS	Mixture of crudes	0.6 mm/yr	Hydrocracker reboiler circuit
Germany	CS	Blend crudes	0.5	HGO draw line
NewZealad	P5 (5Cr-1Mo)	Blend crudes	-------	Furnace tube charge heater
Japan	P5 (5Cr-1 Mo)	Blend crudes	------	CDU /HVU
Saudi Arabia	CS A106	Arab light	0.9 mm/yr	CDU furnace
UAE	CS & P5 (5Cr-1 Mo) & P9	Condensate	>1 mm/yr	Re-boiler(heater) & Charge heater tubes

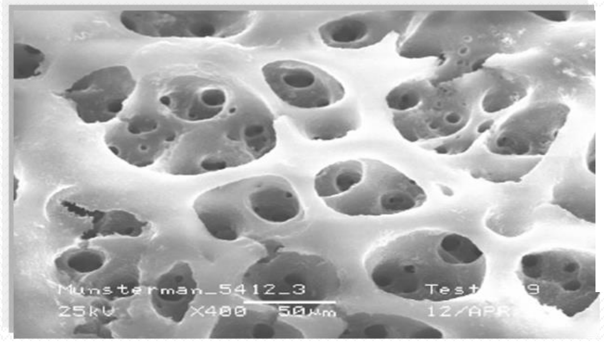
Sulfidation corrosion

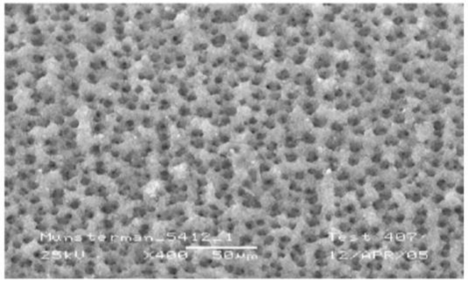
- **Wastage of the wall**
- **1800**
- **With the advent of FCC , coking, and Hydroprocessing**
- **A function of temperature**, **the total sulfur the types of sulfur**, **the type of stream**,
- **above (230 °C).**
- **Set of curves**
- **Prediction** is an elusive **technical challenge**.

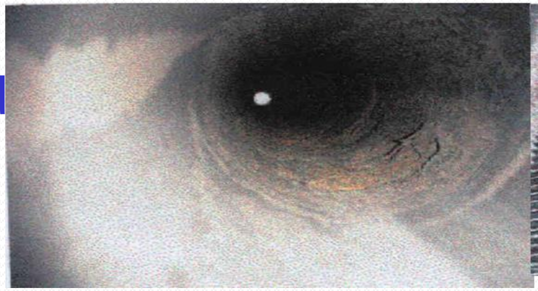


Location of Sulfidation Corrosion

- **Sulfidation** corrosion can occur wherever **sulfur** compounds are present in a hydrocarbon stream and the **temperature** exceeds approximately 230 °C.
- **H2-free** sulfidation occurs in the hotter areas crude, vacuum, coker, visbreaker, and hydroprocessing feed and distillation sections.
- **H2/H2S c**orrosion most commonly occurs in hydroprocessing
- **Organic acids**







PRACTICAL GUIDELINES

1. Existing Units and Components
2. Materials Selection Guidance

H2-free Services

- Carbon steel for temperatures up to (275 °C). Use fully killed steels to assure silicon content > 0.10 wt %.
- 5Cr-0.5Mo for temperatures between (275 °C and 325 °C).
- 9Cr-1Mo above (325 °C).
- 300 Series SS can also be used to virtually eliminate sulfidation corrosion.

PRACTICAL GUIDELINES

H_2/H_2S Services

- With high mole % H2S at metal temperatures above 260 °C), **300 Series SS** are the preferred choice.
- Low ally steel may be used for lower severity services, such as naphtha and kerosene Hydrotreaters with lower mole % H_2S levels**,**

<u>Other considerations</u>

- Heater Tubes
- Linings or Cladding
- Piping Components
- Scaling
- Specification Break
- PMI Program
- Materials Operating Envelope (MOE)

Material Corrosivity Evaluation

- ARRC was requested test a new alloy was developed by M/s Tenaris namely Thor^{TM}115 in comparison to P5 and P9.
- ARRC simulated real refinery conditions in a pilot plant unit that was specially modified
- Actual feedstock and operating conditions used in refineries

TEST OBJECTIVES & METHODOLOGY

OBJECTIVES:

- **To test new alloys and compare with P5 and P9 in a H_2S environment at certain temperatures (390°C and 420 °C):**
- **Prepare coupons and determine corr. rate estimation in line with ASTM G1 and ASTM G4, wherever applicable.**
- **Exposing the coupon samples to H_2S in the range of 9000 – 12000 ppm**

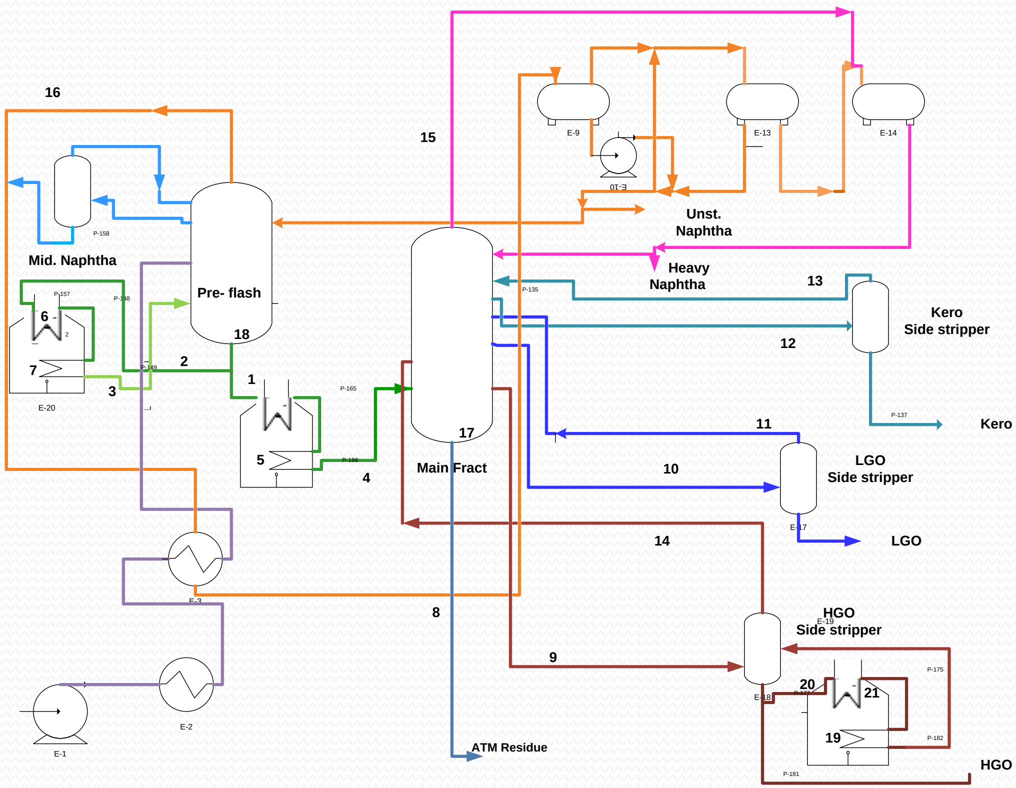


Figure 10: Schematics of process unit with stream numbers

Testing conditions

Process	Feed	Testing environment	Testing condition
Hydro treatment	Heavy Gas Oil (HGO)	H_2S: approx. 1.1% H_2: 98% – 99%	**Pressure:** 40 to 57 bar **Reactor Temp:** Max 400 °C **Coupon Test Chamber Temp:** 390/420 °C

METHODOLOGY

- The three tested materials were designated material numbers, shown in Table 2.
- Each material had 4 coupons, labeled **A** through to **D**

Material	Material number	Coupons
P5	1	1A, 1B, 1C, 1D
P9	2	2A, 2B, 2C, 2D
Thor^{TM} 115	3	3A, 3B, 3C, 3D

Exposure Tests

Test 1

- **FIRST 30 DAYS**
  - ❑ **DURATION**
    - ❑30 days
  - ❑ **TEMPERATURE**
    - ❑390°C
  - ❑ **FEED**
    - ❑HGO
  - ❑ **FEED FLOW RATE**
    - ❑Average: 20.3 cc/hr
  - ❑ **PRESSURE (= H_2 partial pressure)**
    - ❑Average: 56.9 bar

- **EXPOSED COUPONS LAYOUT IN TEST CHAMBER**
  - TOP HOLDER
    - 1A
    - 2A
    - 3A
  - MIDDLE HOLDER
    - 1C
    - 2C
    - 3B
  - BOTTOM HOLDER
    - 1B
    - 2B
    - 3C

Test 2

T boost to 420°C to establish clear comparison at different T severities

- SECOND 30 DAYS
  - **DURATION**
    - 30 days
  - **TEMPERATURE**
    - 420°C
  - **FEED**
    - HGO
  - **FEED FLOW RATE**
    - Average: 19.0 cc/hr
  - **PRESSURE (=H_2 partial pressure)**
    - Average: 57.0 bar

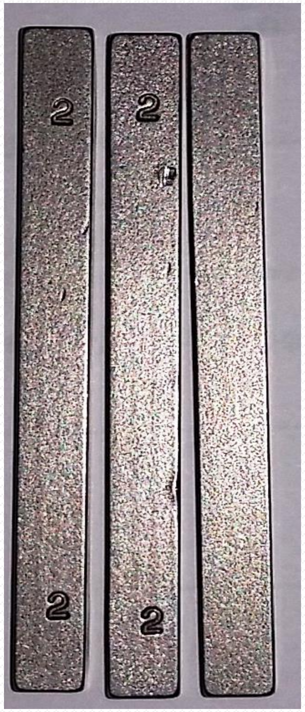
- **EXPOSED COUPONS LAYOUT IN TEST CHAMBER**
  - TOP HOLDER
    - 1A
    - 2A
    - 3A
  - MIDDLE HOLDER
    - 1D
    - 2D
    - 3D
  - BOTTOM HOLDER
    - 1B
    - 2B
    - 3C

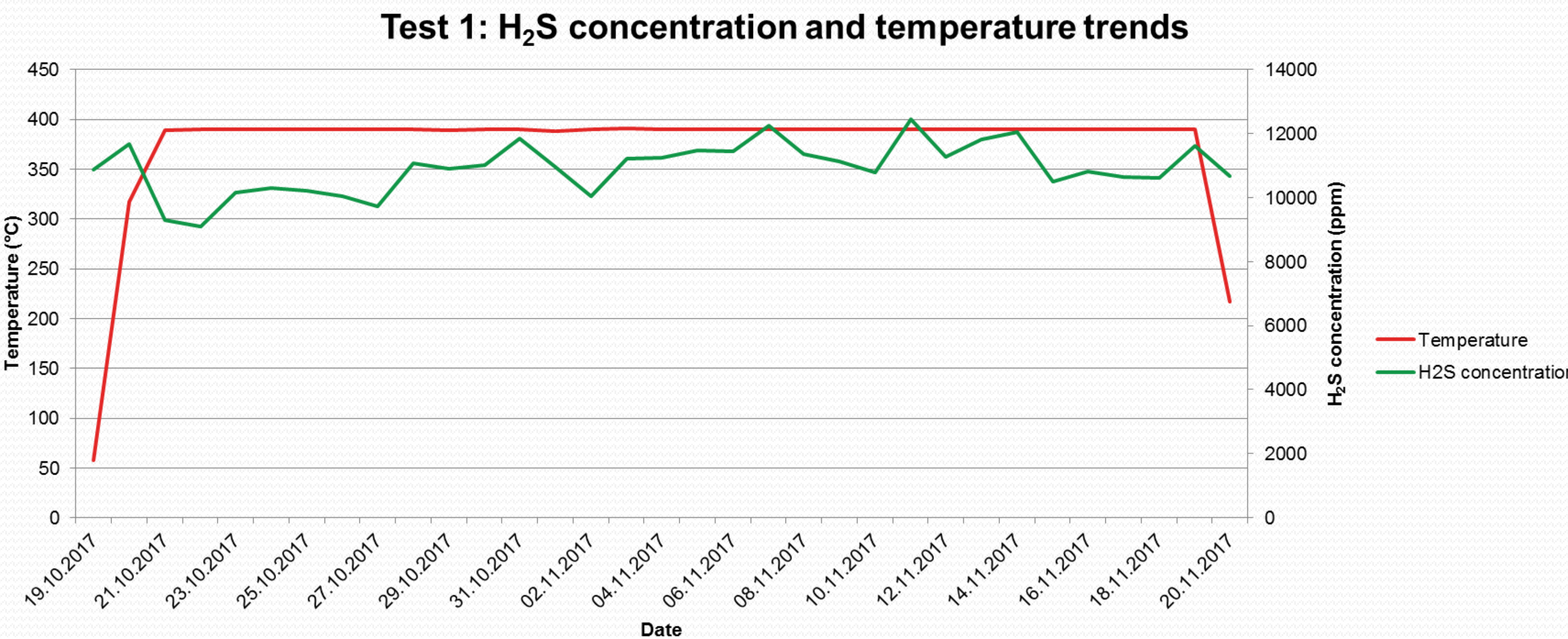
COUPON GROUPS

Table 3: Coupon terminology

Coupon naming terminology		
Test 1	**Middle holder**	
	Coupon Tag number	**Naming**
	1C 2C 3B	Test 1 (390°C) coupons
Test 1&2	**Top holder**	
	Coupon Tag number	**Naming**
	1A 2A 3A	Test 1&2 coupon, or Full run coupons (Top holder)
Test 2	**Middle holder**	
	Coupon Tag number	**Naming**
	1D 2D 3D	Test 2 (420°C) coupons
Test 1&2	**Bottom holder**	
	Coupon Tag number	**Naming**
	1B 2B 3C	Test 1&2 coupon, or Full run coupons (Bottom holder)

Surface Prepared And Cleaned New Coupons Before Exposure




Test 1: H_2S concentration and temperature trends
Temperature (°C)
H_2S concentration (ppm)
Date
Temperature
H2S concentration
0
50
100
150
200
250
300
350
400
450
0
2000
4000
6000
8000
10000
12000
14000
19.10.2017
21.10.2017
23.10.2017
25.10.2017
27.10.2017
29.10.2017
31.10.2017
02.11.2017
04.11.2017
06.11.2017
08.11.2017
10.11.2017
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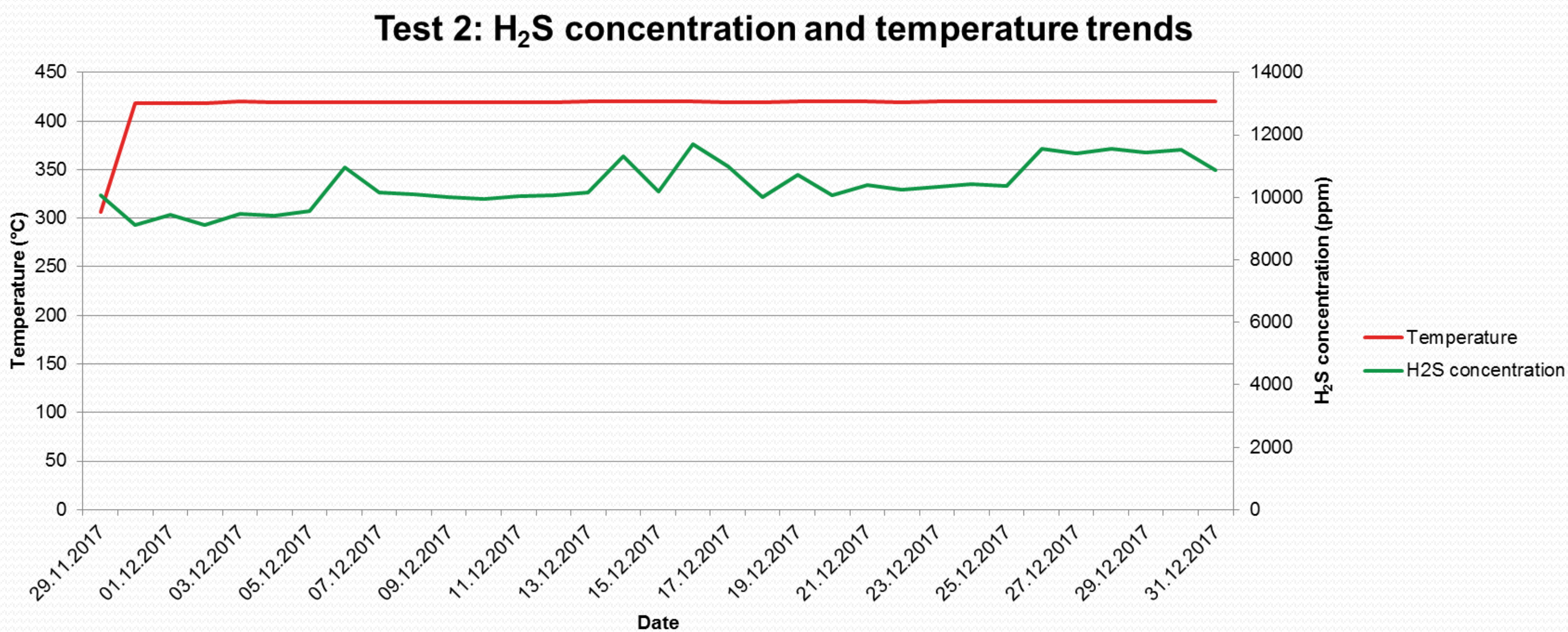
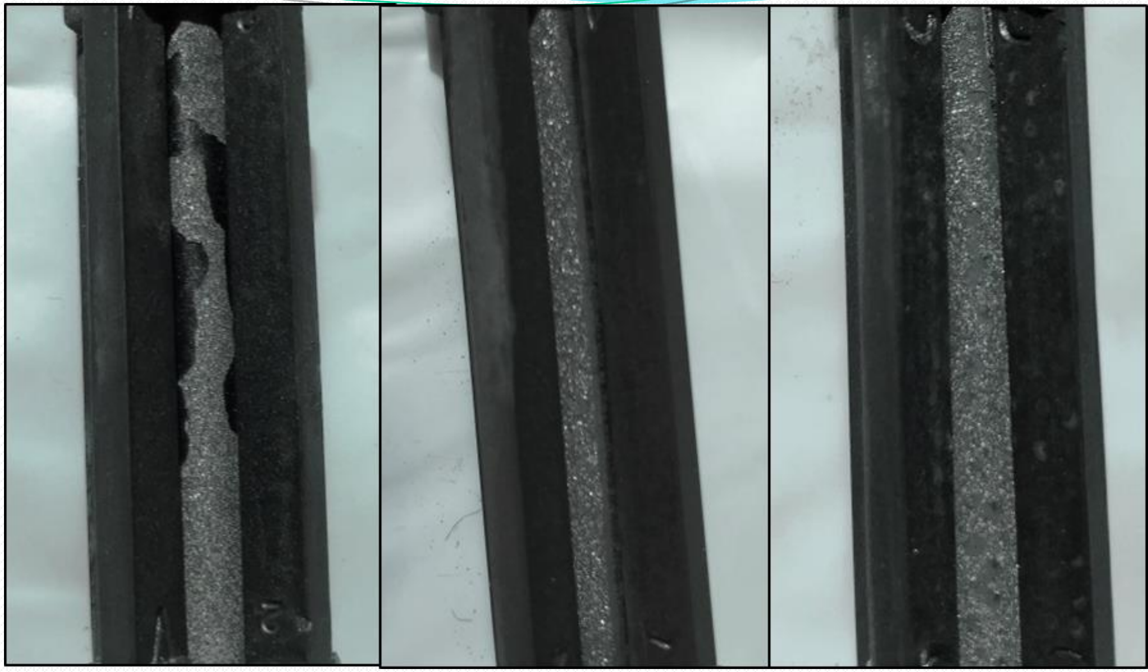
18.11.2017
20.11.2017


Test 2: H_2S concentration and temperature trends
Temperature (°C)
H_2S concentration (ppm)
Date
450
400
350
300
250
200
150
100
50
0
14000
12000
10000
8000
6000
4000
2000
0
29.11.2017
01.12.2017
03.12.2017
05.12.2017
07.12.2017
09.12.2017
11.12.2017
13.12.2017
15.12.2017
17.12.2017
19.12.2017
21.12.2017
23.12.2017
25.12.2017
27.12.2017
29.12.2017
31.12.2017
Temperature
H2S concentration

Coupons after Test 1 upon retrieval. From L to R: Top holder; Middle holder and Bottom holder



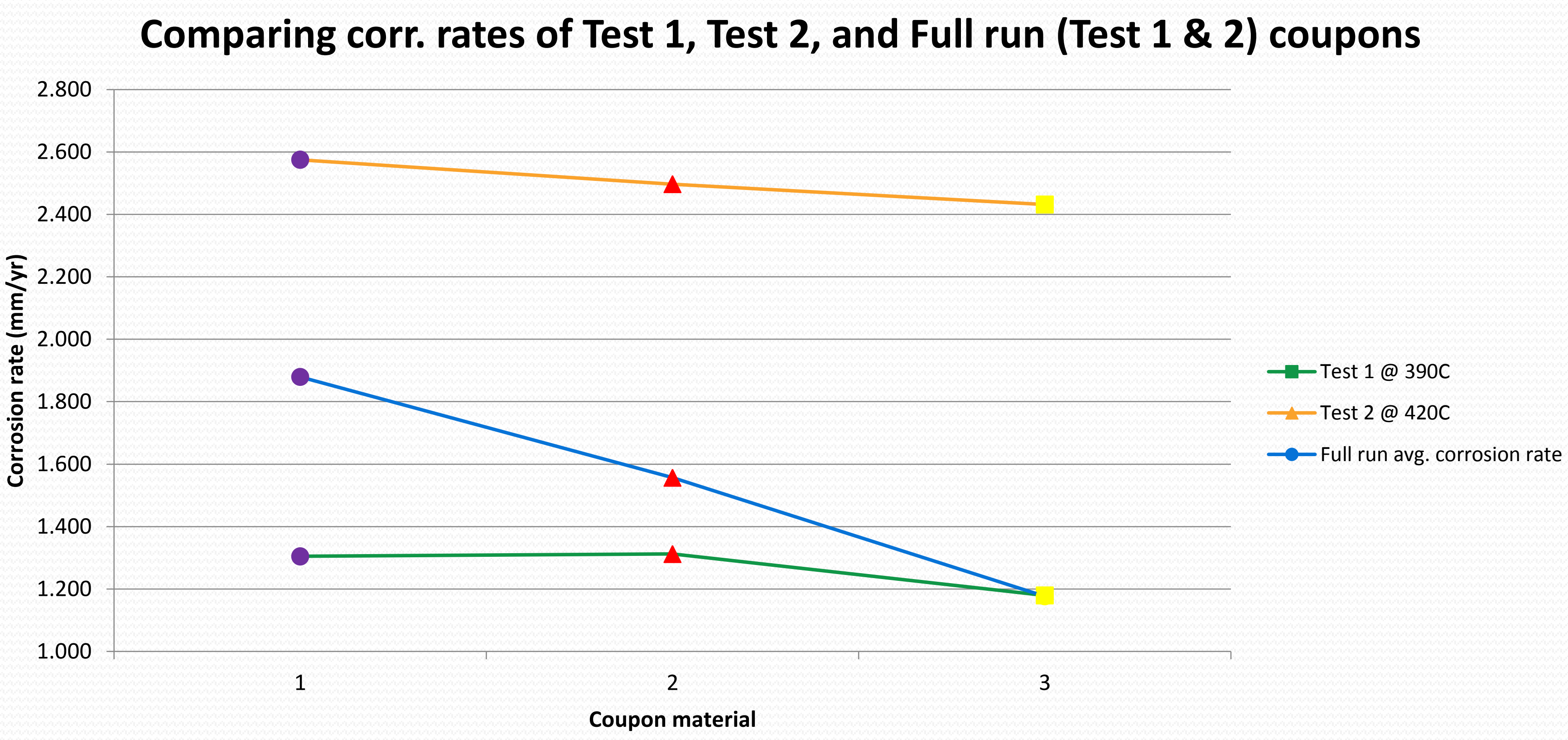
Coupons after Test 2 upon retrieval. From L to R: Top holder; Middle holder and Bottom holder.

Corrosion rate results

- Corrosion rate plots were made for:
  - Test 1 coupons exposed at 390°C
  - Test 2 coupons exposed at 420°C
  - Average corrosion rates for the full run coupons (Test 1 & 2)
  - Comparison of corrosion rates for materials in Test 1, Test 2 and Full run

In order to visualize and compare each material's corrosion rate, specific marker colors and shapes were assigned.

Material	Material number	Marker
P5	1	
P9	2	
Thor ™ 115	3	



Comparing corr. rates of Test 1, Test 2, and Full run (Test 1 & 2) coupons
2.800
2.600
2.400
2.200
2.000
1.800
1.600
1.400
1.200
1.000
Corrosion rate (mm/yr)
1
2
3
Coupon material
Test 1 @ 390C
Test 2 @ 420C
Full run avg. corrosion rate

Summary

- Tested materials not anticipated to be used for these exposure conditions
  - Merely to obtain a comparative results in a short time period
  - The actual corrosion rate values are relevant to the specific test conditions *only*
  - The desired objective of the tests is to rank material performances

- Materials 3 have better resistance to sulfidic environments compared to materials 1 and 2.

Appendix 5

Material selection for heat exchanger tubes in oil refineries

(A. Spaghetti)

OIL REFINERY
SANDVIK HIGH PERFORMANCE MATERIALS

OIL REFINERY

5 TYPE OF PROCESSES:

1. Distillation
   - Atmospheric
   - Vacuum
2. Conversion
   - Decomposition
   - Unfication
   - Reforming
3. Treatment (various)
4. Blending of HC fractions and additives
5. Others

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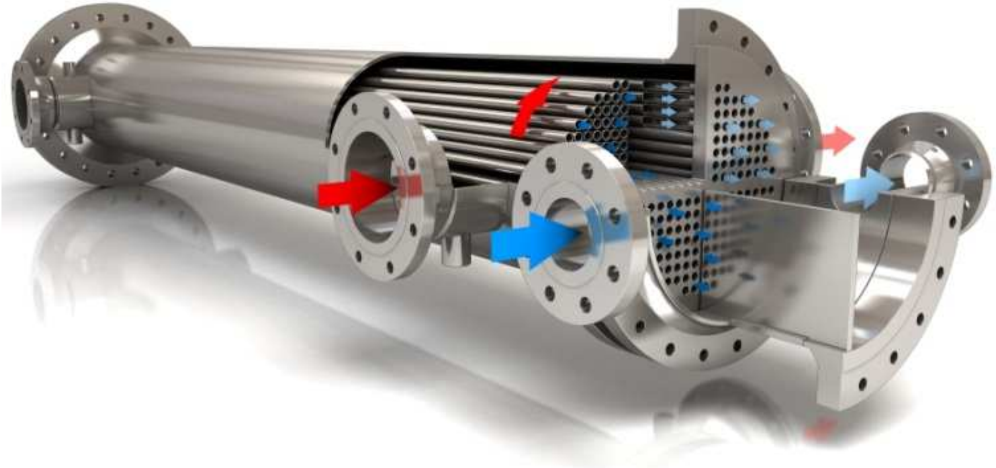
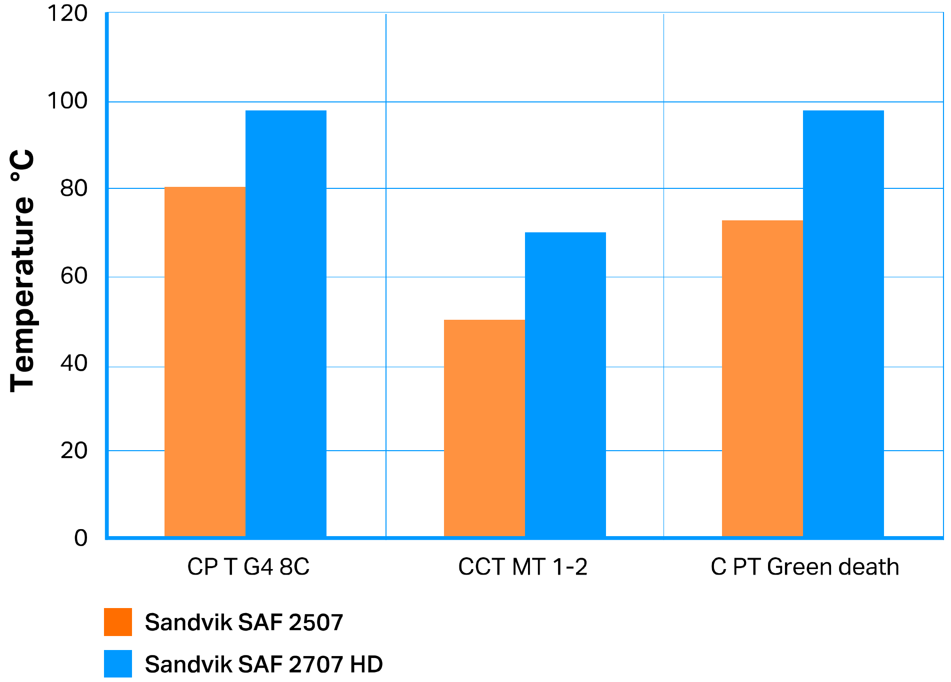
CDU – OVERHEAD CONDENSER

CORROSION RISKS

- Pitting and crevice corrosion
- HCl (dewpoint) corrosion
- Salt residues in crude oil → under deposit corrosion
- Solid deposits of ammonium chloride (→ under deposit corrosion) ← injection of ammonia to neutralize
- Increased use of sour crude → H_2S
- Stress Corrosion Cracking
- Microbiological Induced Corrosion



PITTING AND CREVICE CORROSION

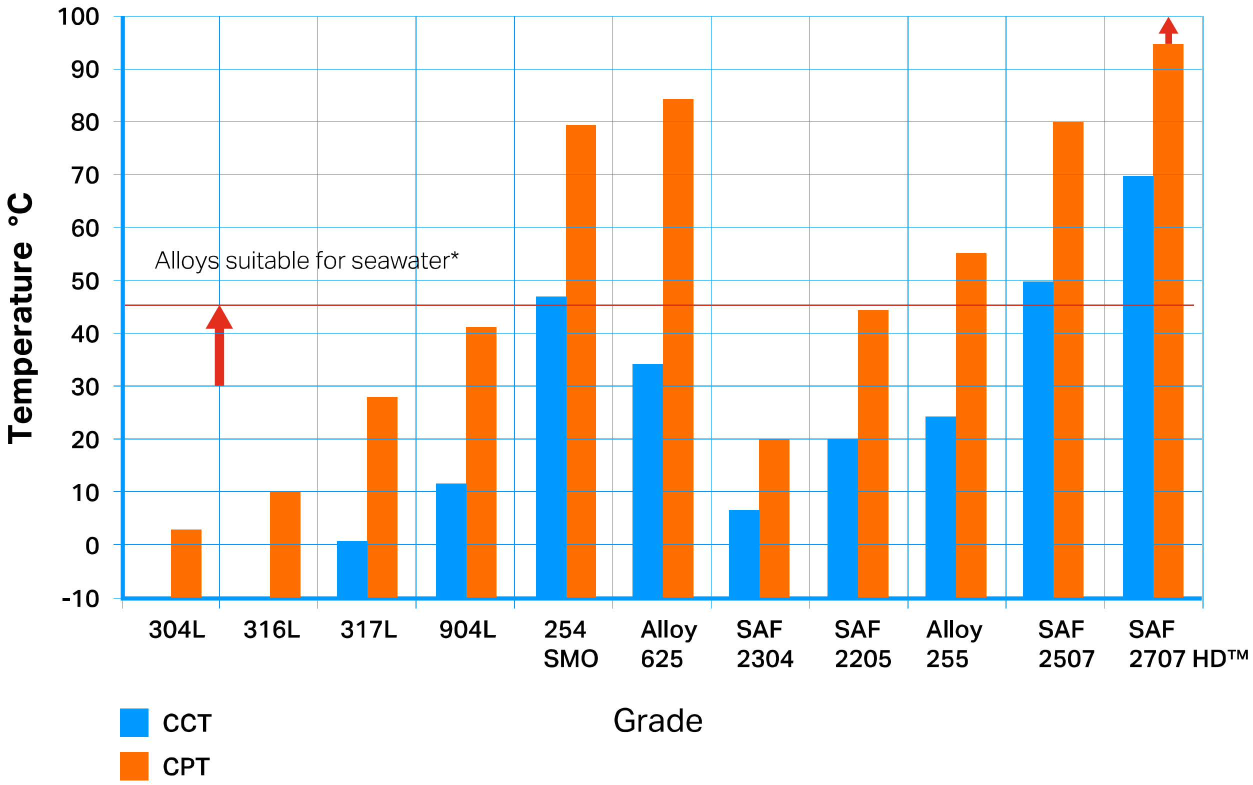


Critical pitting temperature measured in modified G48A and "Green death". Critical crevice corrosion temperature obtained in testing with a crevice specified in the MTI-2 procedure.

	SAF 2507®	SAF 2707 HD™
Max crevice temp	40°C	70°C
Min flow rate	1 m/s	1 m/s
Max tube wall temp	60°C	90°C

Value for SAF2507® and SAF2707HD™ in seawater.

PITTING AND CREVICE CORROSION

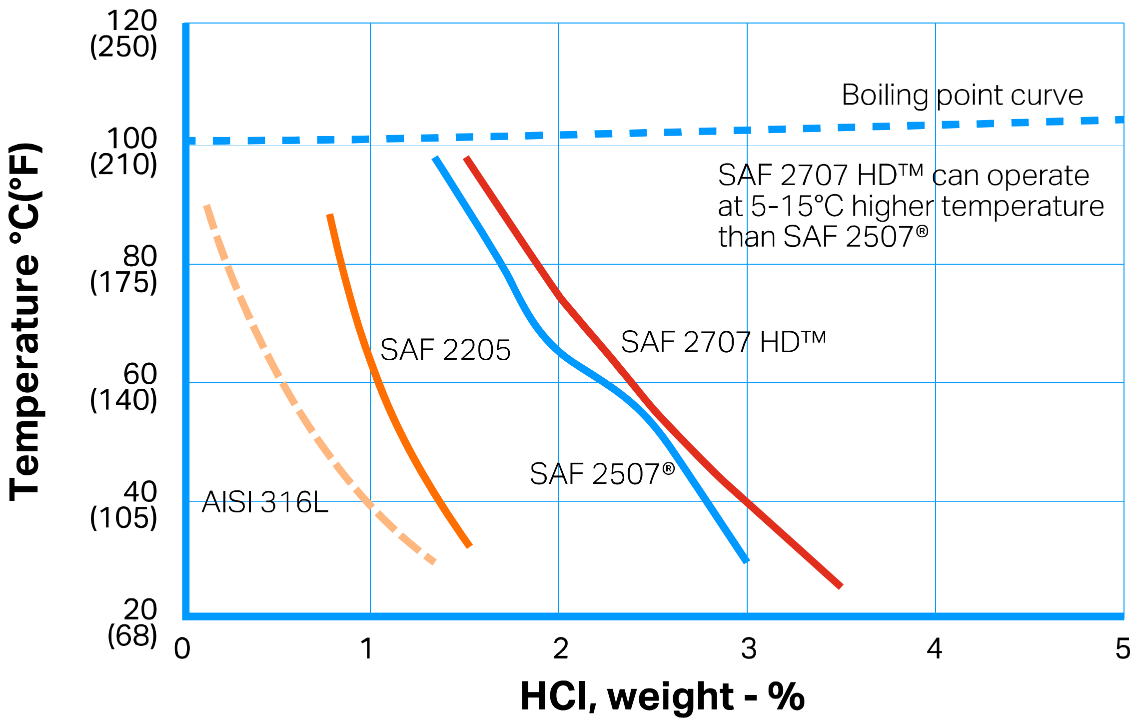


CCT = critical crevice temperature G 48 B

CPT = critical pitting temperature G 48 A

*Based on more than 20 years practical experience

HYDROCHLORIC ACID CORROSION



Isocorrosion diagram 0,l mm / year

SALT RESIDUALS AND SOLID DEPOSITS

- Hydroxides, carbonates, sulfates, nitrates ad phosphates have an inhibition effect on pitting, but then can form deposits → under deposit corrosion
- Pitting resistance is impaired by stagnant solutions
- High flow rate of chloride containing water in tubular heat exchanger will keep the surface clean both from deleterious species at pitting sites and from fouling which could otherwise reduce heat transfer
- Flow rate below 1 m/s should be avoided

SOUR CRUDES

LOW PH AND/OR HIGH CHLORIDES CONCENTRATION

Hydrogen Embrittlement (ferrite)
Low Temperature (SSC)

- Metal corrodes and H^+ is reduced to H_2
- Two H_2 can migrate on the surface and leave the metal as H_2
- H^+ can be absorbed into the metal
- HS^- and S^- retard H^+ recombinations

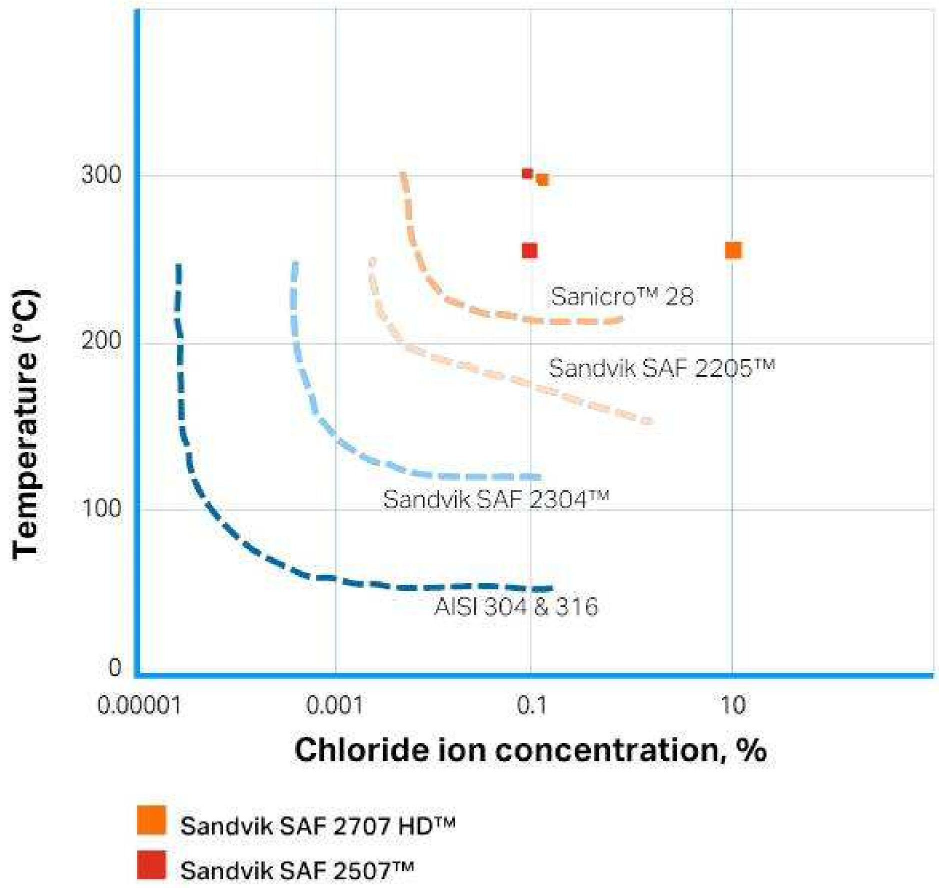
Stress Corrosion Cracking (austenite)
High temperature

- H_2S promotes formation metal sulphides on the metal on the SS surface
- Non passivating surface layer
- Promote growth of pitting and crevice corrosion
- Lead to SCC of austenite (induced by chlorides)

STRESS CORROSION CRACKING

INDUCED BY CHLORIDES

- Autoclave
- 100 bar
- 8 ppm O_2
- Load = proof strength
- NaCl-solution
- 1000h (6 weeks)



NACE MR0103

MATERIALS RESISTANT TO SULFIDE STRESS CRACKING IN CORROSIVE PETROLEUM REFINING ENVIRONMENT

- Aims at refinery application
- Controlled environment
  - Low salinity
  - Low H_2S
  - Controlled pH
- Material qualification is based on alloy composition and hardness

> 1.3.5.1.1 The high-pH sour environments differentiate refinery sour service from the oil and gas production sour environments covered by NACE MR0175/ISO 15156, because many wet sour streams in production also contain carbon dioxide and hence exhibit a lower pH. Another major difference is that chloride ion concentrations tend to be significantly lower in refinery sour services than in oil production sour services.

NACE MR0103

MR0103-2012

2.8 Duplex Stainless Steel Materials

2.8.1 Wrought and cast duplex stainless steel products shall be in the solution-annealed and liquid-quenched condition. Tubing shall be rapidly cooled by liquid quenching, or by air or inert gas cooling to below 315 °C (600 °F). The ferrite content shall be 35 to 65 vol%. Aging heat treatments to increase strength and/or hardness are prohibited because of the formation of embrittling phases.

2.8.1.1 The hardness of grades with PREN ≤ 40% according to Equation (1) shall not exceed 28 HRC.[(10)]

2.8.1.2 The hardness of grades with PREN > 40% according to Equation (1) shall not exceed 32 HRC.[(10)]

2.8.2 Welding of Duplex Stainless Steels

2.8.2.1 Fabrication and repair welds in all wrought and cast duplex stainless steels shall be produced using a welding procedure qualified by performing the following tests on specimens taken from the WPQT coupon(s):

2.8.2.1.1 A hardness survey shall be performed in accordance with Appendix C. The average hardness shall not exceed 310 HV, and no individual reading shall exceed 320 HV.

2.8.2.1.2 Metallographic ferrite measurements shall be performed in accordance with ASTM E562.[19] The average ferrite content in the weld deposit and HAZ shall be within the range of 35 to 65%, with a relative accuracy of 10% or lower.

2.8.2.1.3 Technical considerations for qualification of welding procedures for duplex stainless steels are included in Appendix D (nonmandatory).

MICROBIOLOGICAL INDUCED CORROSION

WITH CHLORINATION

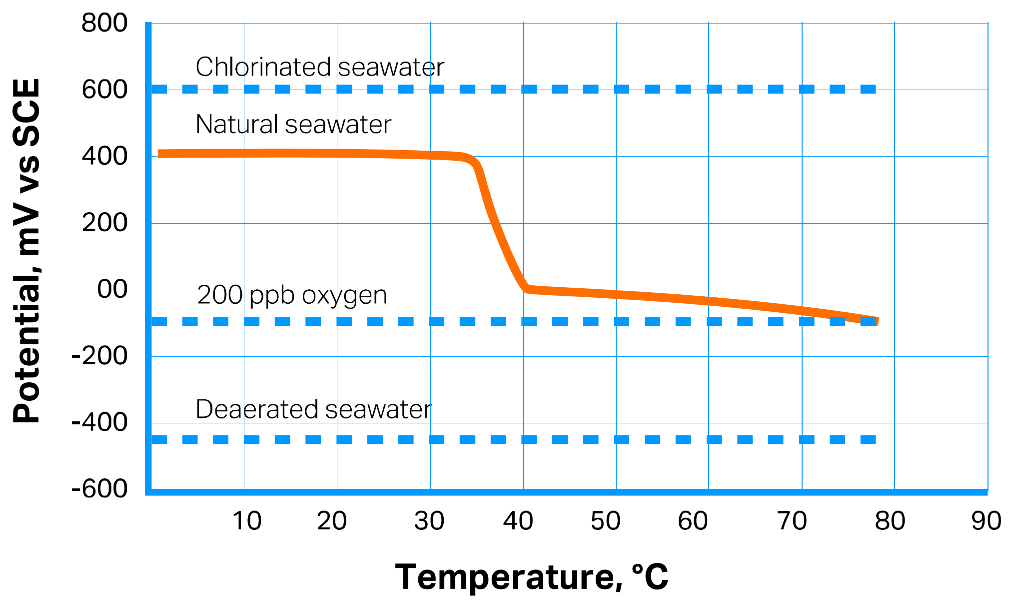
- Corrosive environment
- Pitting corrosion is a common problem in stagnant seawater
- Cl_2 is an oxidant commonly added to seawater exchangers to mitigate against biofouling
- Cl_2 increase the electrochemical potential
  $\Rightarrow$ increase the severity of the environment
  $\Rightarrow$ pitting corrosion

WITHOUT CHLORINATION

- Active microorganisms stick to the surface
- Reduced heat transfer and risk for crevice corrosion (Microbiological Induced Corrosion "MIC")

CHLORINATION

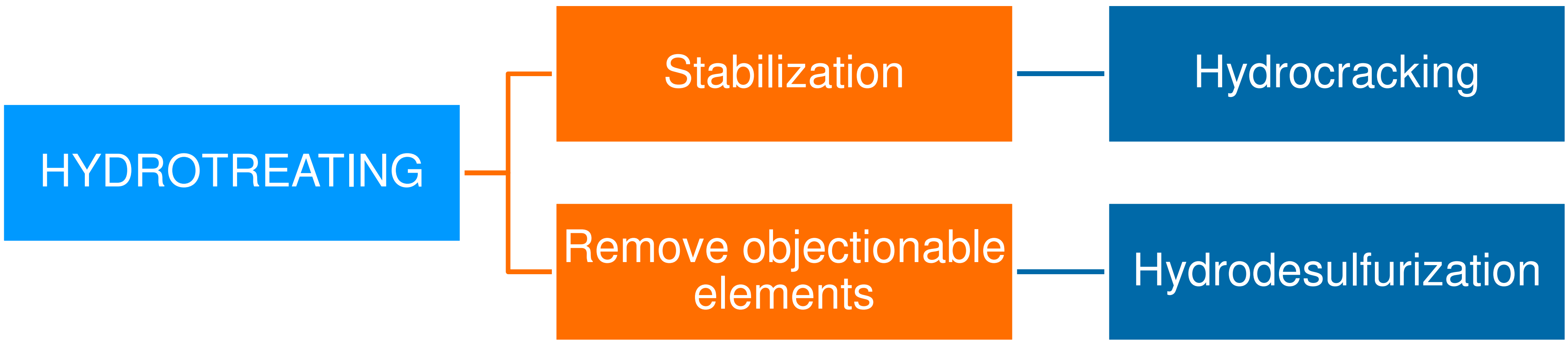
- Cl_2 is an oxidant commonly added to seawater exchangers to mitigate against biofouling
- Cl_2 increase the electrochemical potential → increase the severity of the environment → pitting corrosion



HYDRODESULFURIZATION

HYDROTREATING

«PROCESS TO CATALYTICALLY STABILIZE PETROLEUM PRODUCTS BY CONVERTING OLEFINS/AROMATICS TO PARAFFINS OR REMOVE OBJECTIONABLE ELEMENTS FROM PRODUCTS OR FEEDSTOCKS BY REACTING THEM WITH HYDROGEN»



COMMON CORROSION RISKS

COMMON CORROSION RISKS

- Chlorides
  - SCC of low-alloyed stainless steel grades like 304 and 316
  - Pitting corrosion at stagnant conditions and high chloride content
  - Crevice corrosion if there is risk for fouling
- H_2S
  - Hydrogen embrittlement of ferritic materials
  - Chloride induced corrosion
- Ammonium compounds
  - Under deposit corrosion
  - Ammonium salts can cause erosion on soft material
- Polythionic acid
  - Can cause “stand still corrosion”
- Solid deposits (expecially ammonia salts)
  - Can cause erosion of tube ends leading to leakage

SANDVIK

MATERIAL SOLUTION

- Good – Sandvik SAF 2205®
  - Widely used in refineries
- Better – Sandvik SAF 2507®
  - Improved resistance to chloride induced localized corrosion and SCC
- Best – Sandvik SAF 2707 HD™
  - Excellent resistance to chloride induced localized corrosion and SCC
- For higher temperatures (> 300°C)
  - Sanicro™ 28 and Sanicro™ 41
  - Offer very good H_2S resistance and excellent SCC resistance

SANDVIK

SANICRO™28 ADVANTAGES IN REFINERIES APPLICATIONS

THE SANICRO™ FAMILY

- <u>SA</u>ndvik <u>NI</u>ckel <u>CRO</u>mium
- % Ni > 8: the structure is fully austenitics
- Other alloy elements make materials «multi-purpose»

<u>Most used SANICRO in refineries</u>

Grade	C	Si	Mn	P	S	Cr	Ni	Mo	Cu	Ti
SANICRO™ 28	≤0,020	≤0,6	<2,0	≤0,025	≤0,010	27	31	3,5	1,0	
SANICRO™ 41	≤0,030	≤0,5	0,8	≤0,025	≤0,010	20	38,5	2,6	1,7	0,7

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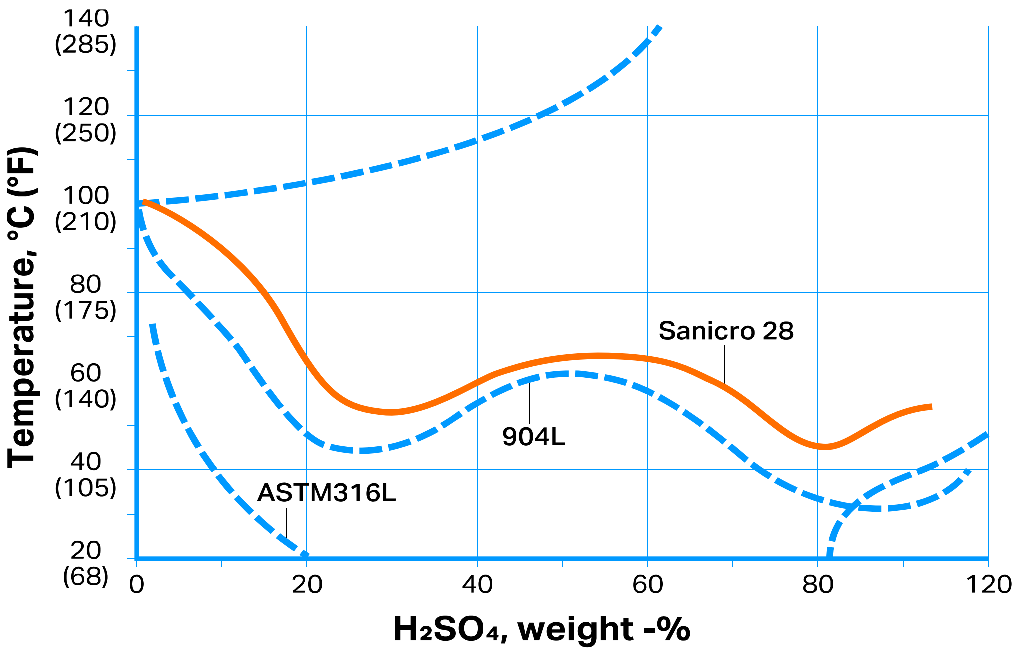
CORROSION RESISTANCE

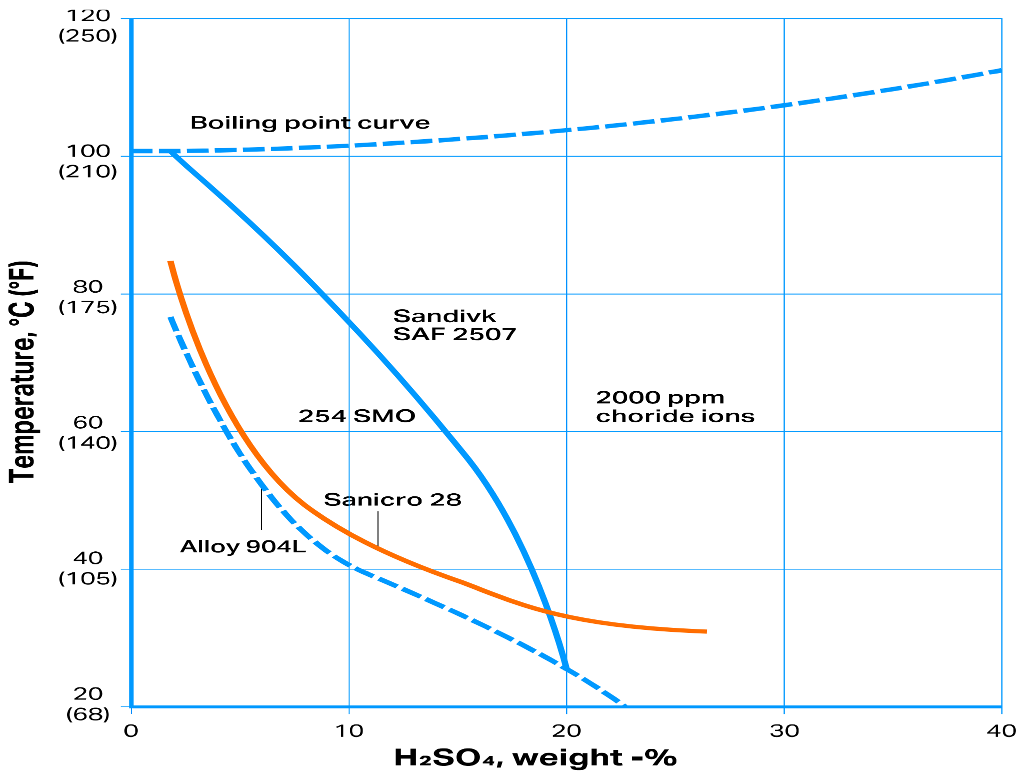
GENERAL CORROSION



- Isocorrosion diagram for Sanicro™ 28, 904L and ASTM 316L, in deaerated sulphuric acid
- The curves represent a corrosion rate of 0.1 mm/year (4 mpy)

CORROSION RESISTANCE

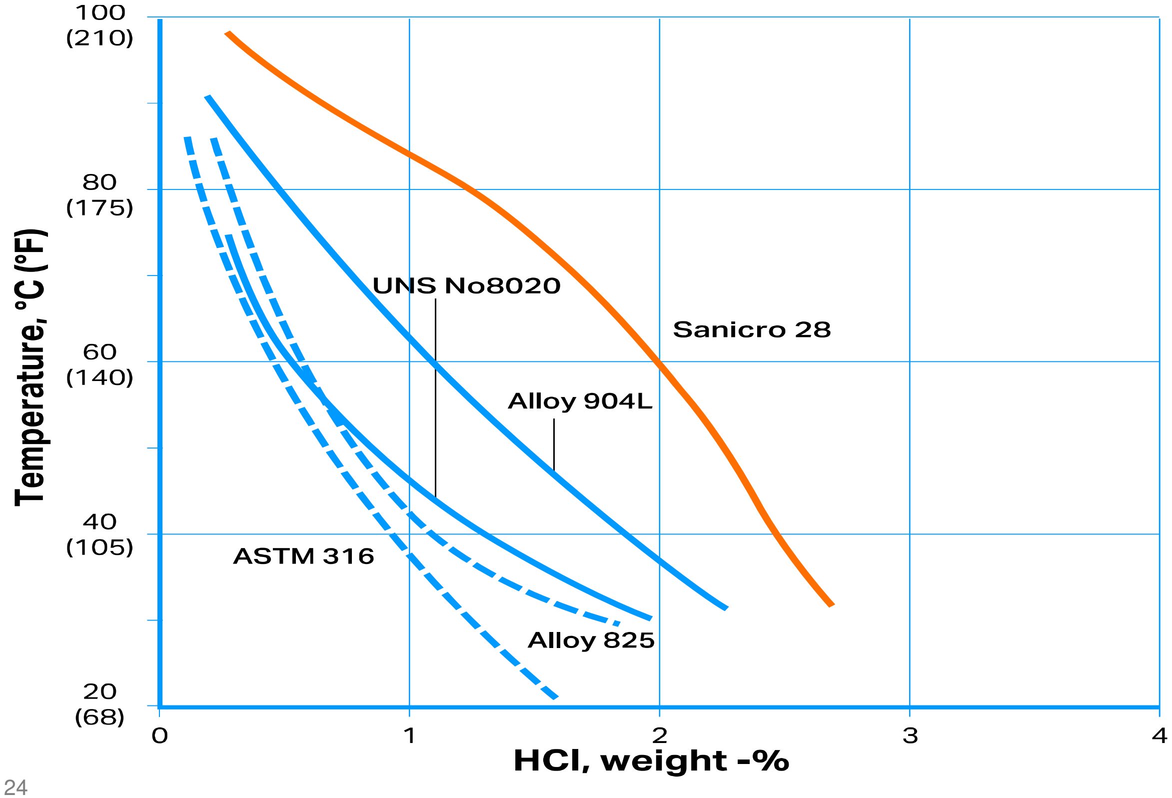
GENERAL CORROSION



- Isocorrosion diagram for Sanicro™ 28 in sulphuric acid containing 2000 ppm chloride ions at a corrosion rate of 0.1 mm/year (4 mpy)

CORROSION RESISTANCE

GENERAL CORROSION



- Isocorrosion in hydrochloric acid. The curves represent a corrosion rate of 0.1 mm/year (4 mpy).

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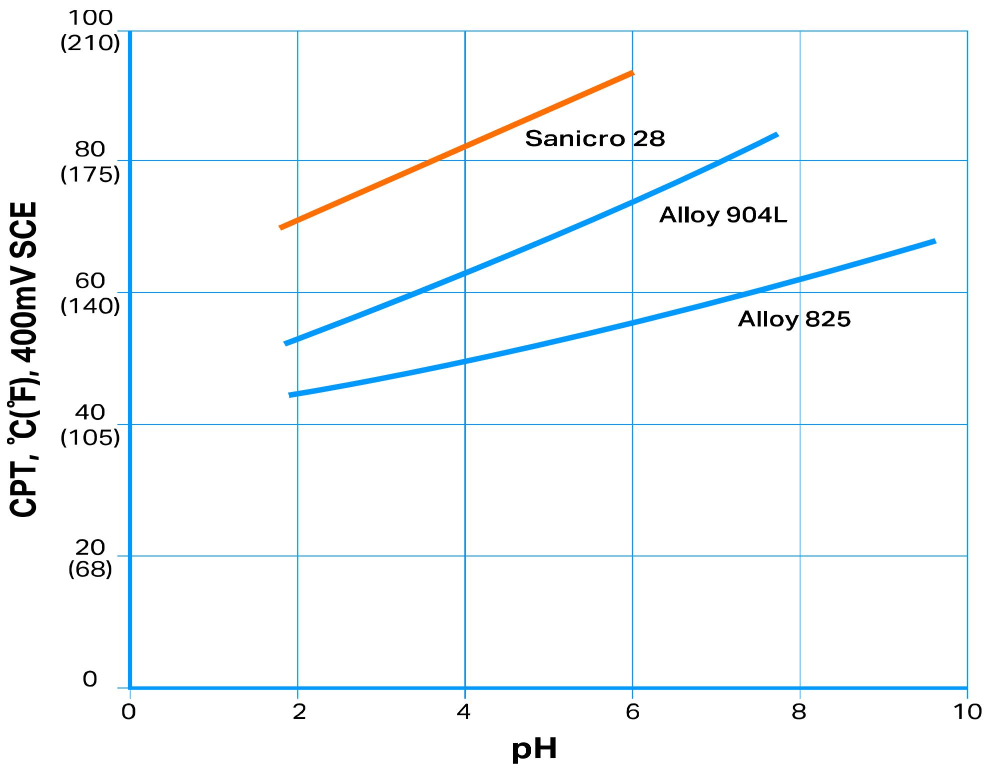
CORROSION RESISTANCE

PITTING CORROSION



- Critical pitting temperature (CPT) at +400 mV SCE for different alloys in synthetic seawater (3% NaCl), at different pH values

PRE = % Cr + 3.3 x % Mo + 16 x % N

$PRE_{SAN28}=38$ > $PRE_{SAN41}=28$

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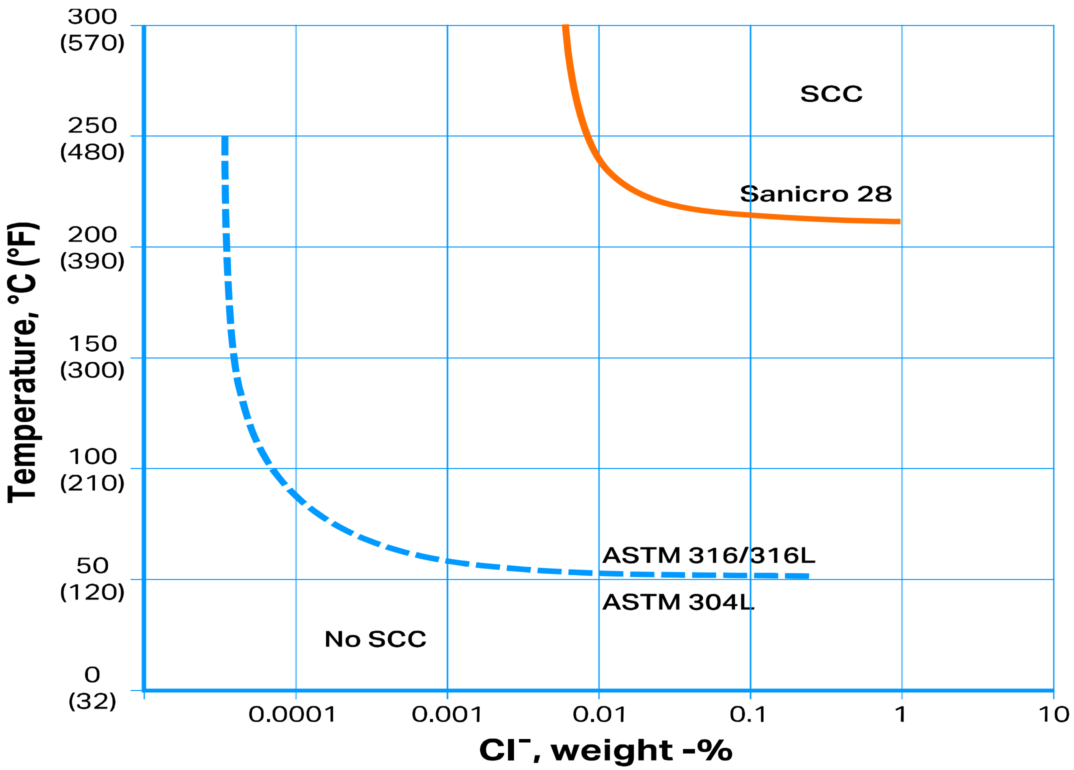
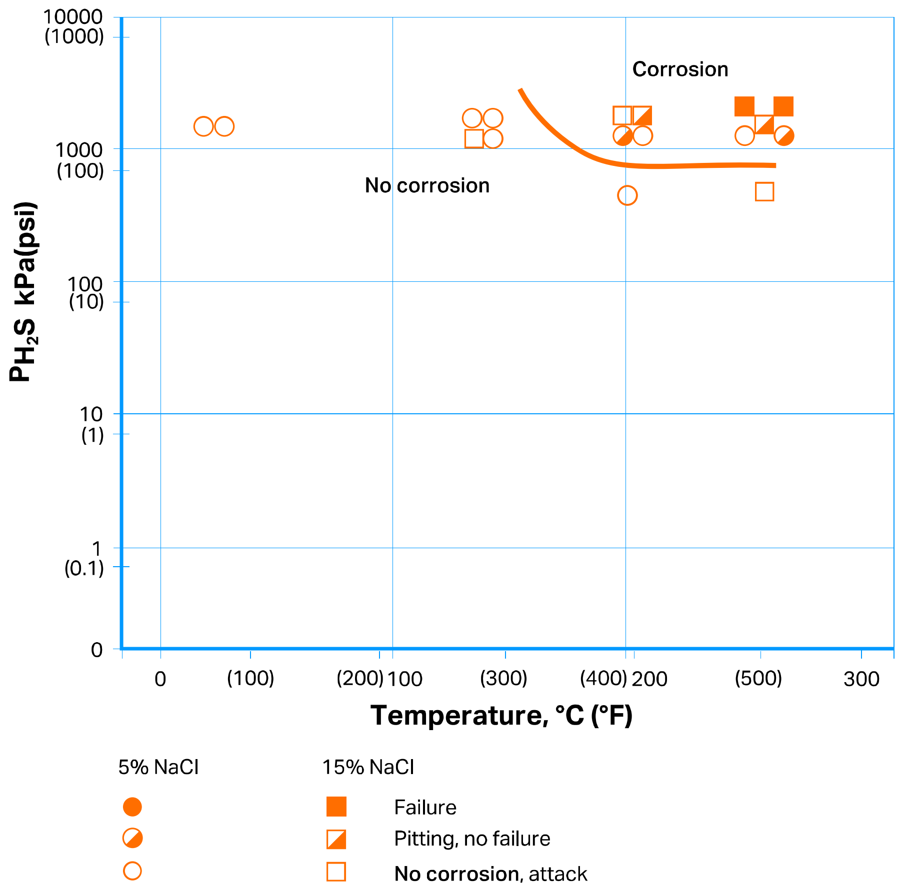
CORROSION RESISTANCE

STRESS CORROSION CRACKING



- Results of stress corrosion cracking tests on different steel grades in 40% $CaCl_2$, at 100 °C (210 °F), pH = 6,5

LABORATORY TEST CONDITIONS: R&D



- Sanicro™ 28 laboratory sour test result. All specimens stressed to 100% of yield strength.
- pH 2.9
- (1) 5% NaCl (30,000 ppm Cl^-)
- (2) 15% NaCl (90,000 ppm Cl^-)

Sanicro™ 28 can be used safely at high H_2S partial pressures and temperatures without any corrosion

SANICRO™ 28: WHEN & WHY?

- Sanicro™ 28 is suitable in special demanding applications:
  - –heat exchangers with temperatures above 250 °C
  - –Alternative to Alloy 825 (Sanicro™ 41)
- Sometimes refinery conditions are high in H_2S and with low pH
  - –Duplex or super duplex should not be used
  - –Sanicro™ 28 suitable material choice

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DISCUSSION

- H_2S in itself is not corrosive for stainless steel, due to its weak acidity and dew point
- In combination with a low pH and/or high chloride concentration it can enhance hydrogen absorption which can lead to hydrogen embrittlement of ferrite phase and/or sulphide stress cracking (SSC)
- According to NACE MR0175-ISO 15156-1:2003, Sanicro™28 is categorized as solid solution nickel based alloy group 4c and is recommended for any application under the conditions described by Table 2
- In an H_2S environment, Sanicro™ 28 in cold worked condition showed excellent resistance to stress corrosion cracking / sulphide stress corrosion attack

SUMMARY

- Sanicro™ 28 is a high end material exhibiting very good corrosion resistance and mechanical properties
- Sanicro™ 28 has:
  - Worse resistance towards chloride induced localised corrosion than super duplex and 6Mo austenitic grades
  - Better resistance towards chloride induced localised corrosion than 2RK65 (904L)
  - Better resistance towards H_2S containing environments than super duplex grades
- NACE MR0175 should not be used for material specifications for refinery applications, introducing NACE MR0103 (material qualification is based on alloy composition and hardness)

THANKS FOR THE ATTENTION

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Appendix 6

Corrosion during water washing of CDU overheads

(M. De Marco)

ISTITUTO ITALIANO
DELLA SALDATURA
Il Gruppo

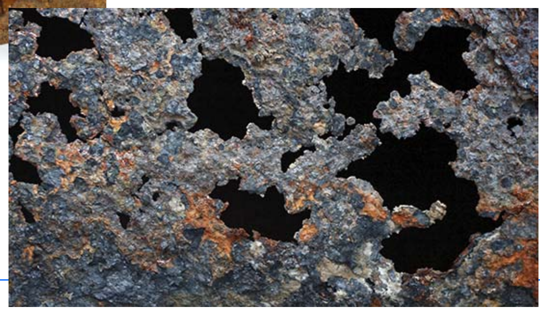
ISTITUTO ITALIANO DELLA SALDATURA

Is Water washing in CDU overhead always beneficial?

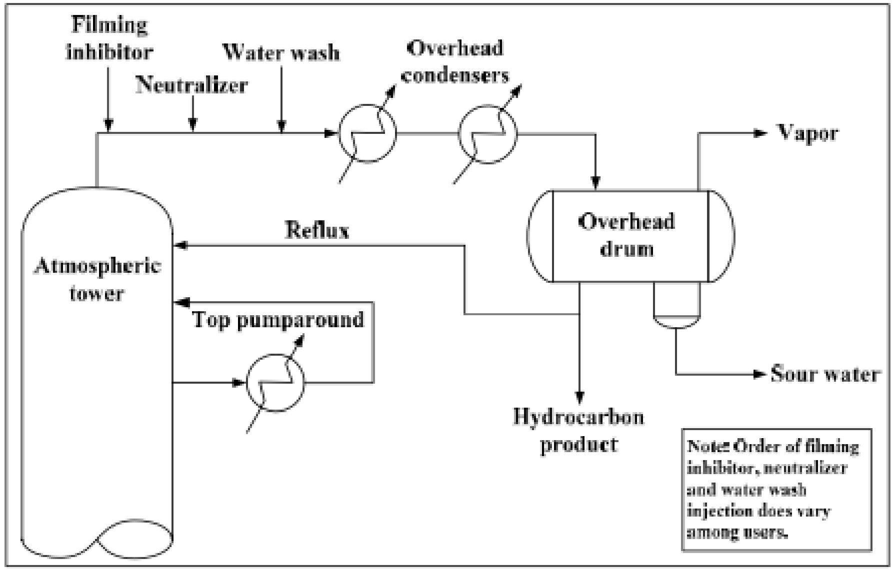
M. De Marco

INTRODUCTION

- CDU overhead corrosion control can be a very challenging job
- Corrosion by acid condensate (HCl and other inorganic and organic acids)
- Fouling by salts (acidic) and corrosion products (UDC)
- For overhead corrosion and fouling to occur HCl vapor has to:
  - Dissolve in water condensate
  - React with ammonia vapor and form ammonium hydrochlorides salts
  - React with liquid organic neutralizers and form neutralizer hydrochloride salts
  - Penetrate existing corrosion deposits on metal surface
  - Penetrate existing corrosion inhibitors film



- CDU overhead corrosion mitigation starts from crude feed to the Unit.
  - Crude tank settling
  - Desalting
  - Caustic addition
  - Overhead control as injection of inhibitors, neutralizers and water washing
  - Monitoring of Key Performance Indicators (KPIs as pH, Chlorides, Iron, etc.) and Operating Windows (OWs)
  - Inspection strategies
  - Metallurgical upgrades to CRA (the right one!)

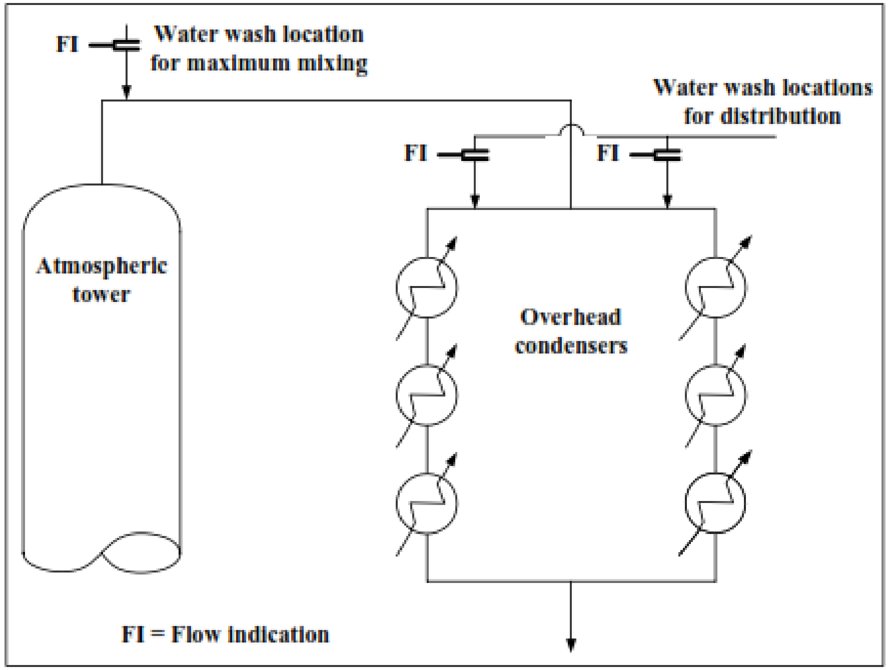


- In general water wash injection into overhead systems should not be necessary if the crude charge is properly desalted (< 3,5 ppm salt) -> Overhead water condensate with Cl^- < 20 ppm.
- No ammonium chloride and/or neutralizer hydrochloride salts are likely to form as long as the dew point exceeds 110 °C (safety margin often applied).
- The principal objective of water injection is to
  - remove deposits of salts and corrosion products (crude no longer properly desalted or increasing frequency of desalter upset).
  - scrub some of the salt-forming contaminants from the overhead vapor before they have a chance to react.
  - raise the pH at the aqueous dew point, which occurs at the point of water injection.
- NOTE: Water injection can dilute also HCl but even an optimistic ten fold dilution corresponds in any case to high and unacceptable corrosion rate.
- NO matter how well planned and implemented, water injection by itself is non substitute for other OVHD corrosion control measure.

- WW quantity
  - 5-15 % of total overhead vapor rate.
  - the volume of water required to bring the atmospheric tower overhead stream to the aqueous dew point plus some free excess water (10-25 %).

- WW quality
  - Recycled Water from the atmospheric tower overhead drum is a common source. locally available, air-free (oxygen contamination can accelerate corrosion). In addition to low oxygen content, other characteristics of good wash water include low solids content and relatively neutral pH
  - BFW, although costly (oxygen free).
  - Stripped sour water (low in oxygen and, with good sour water stripper operation, low in NH_3, H_2S and acids).
  - Fresh water such as well water, surface water, raw water, cooling water, and cooling tower blowdown are not normally considered good water sources because they contain oxygen.

- WW injection point
  - Atmospherics tower overhead line -> for maximum contact time, scrubbing and effect on dew point.
  - Close to the inlet of the overhead condenser bundles -> for maximum distribution to the banks

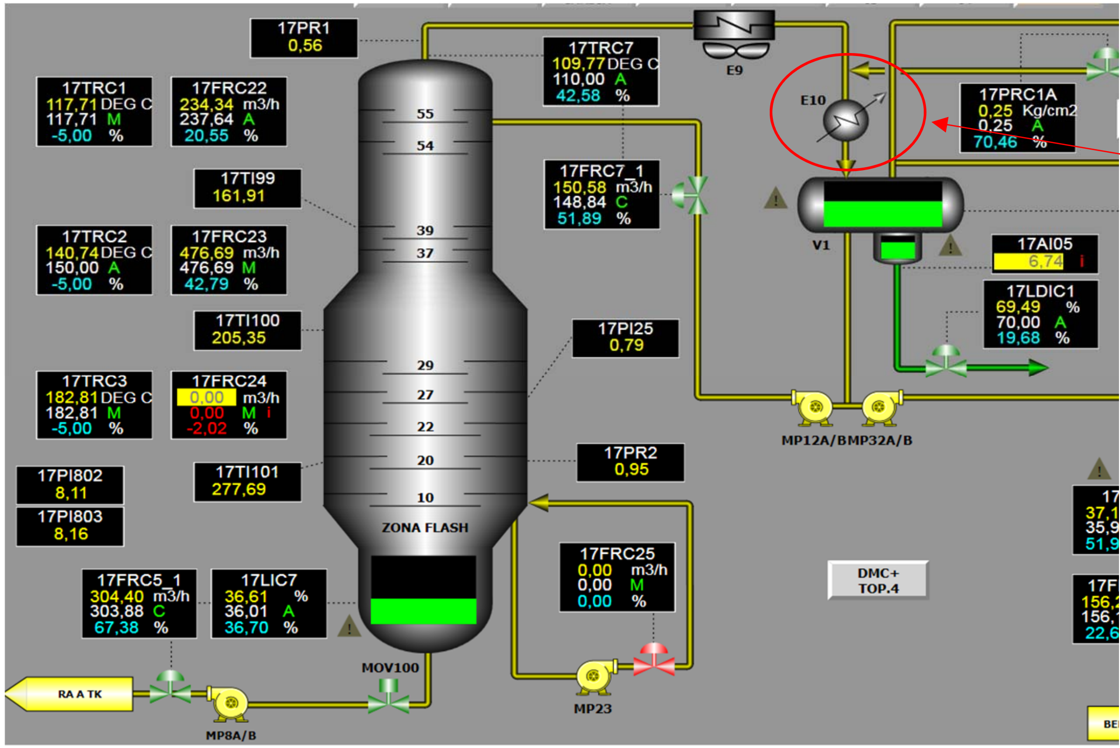


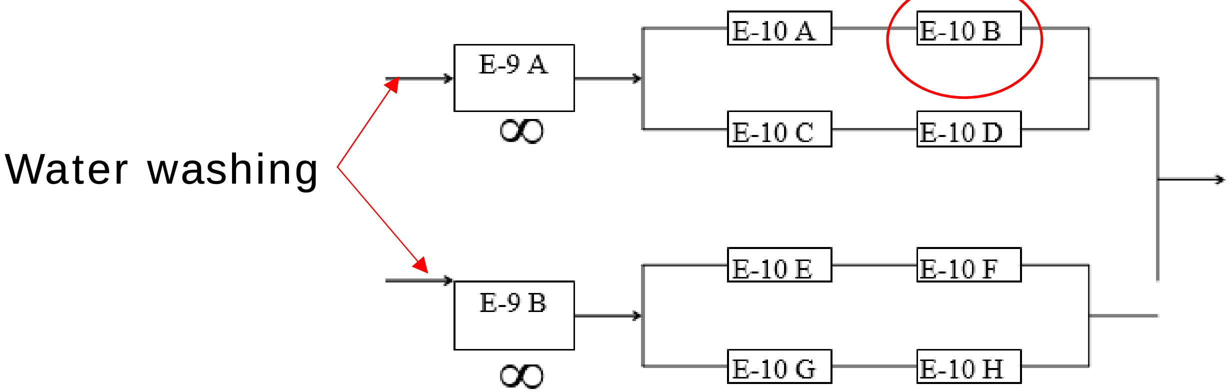
- Problems with WW
  - Previously dry components can become wet and in certain cases experience acid corrosion (especially if insufficient water is injected).
  - Dissolved air (O_2) can induce corrosion.
  - Impingement problems in high velocity area (usual limits of wet stream in OVHD 9-15 m/s) -> elbows, change in flow direction, inlet area of HEs.
  - Not proper distribution of WW in HEs parallel banks.
  - Process issues -> heat balance in HEs

CASE HISTORY #1

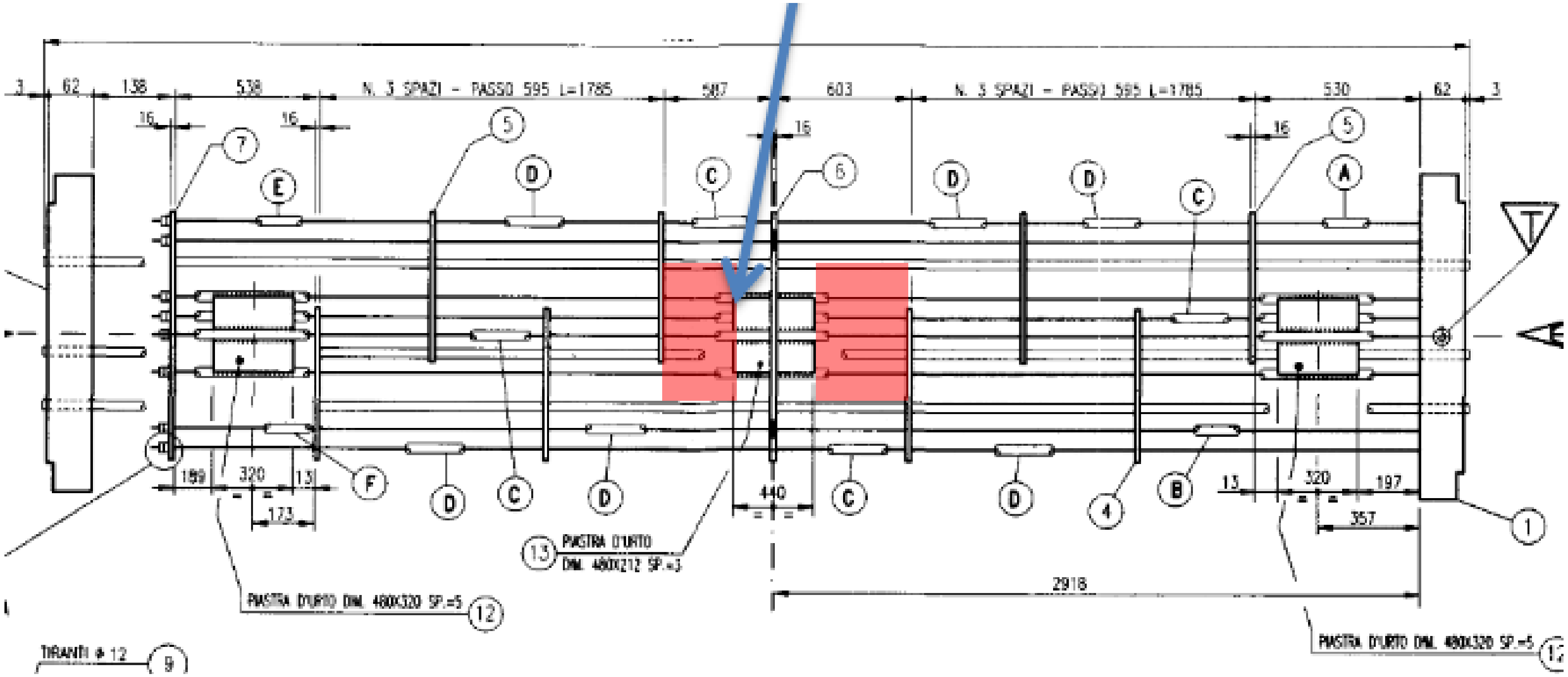
- Overhead condenser CDU unit
- Corrosion phenomena of tubes close to inlet nozzle
- Corrosion close to impingement plate
- Water washing implemented on the vapour line ahead since last 2 years
- Water used -> water from SWS
- Corrosion increased in the last 2 years (bundle installed in 2016)
- Injection of neutralizer and inhibitor on the vapour line

CASE HISTORY #1



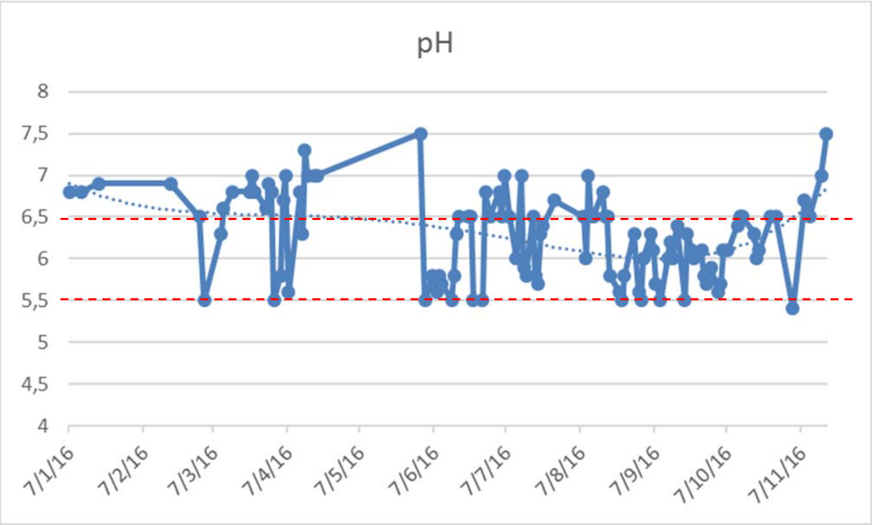


Top view of the bundle with area of preferential corrosion of tubes

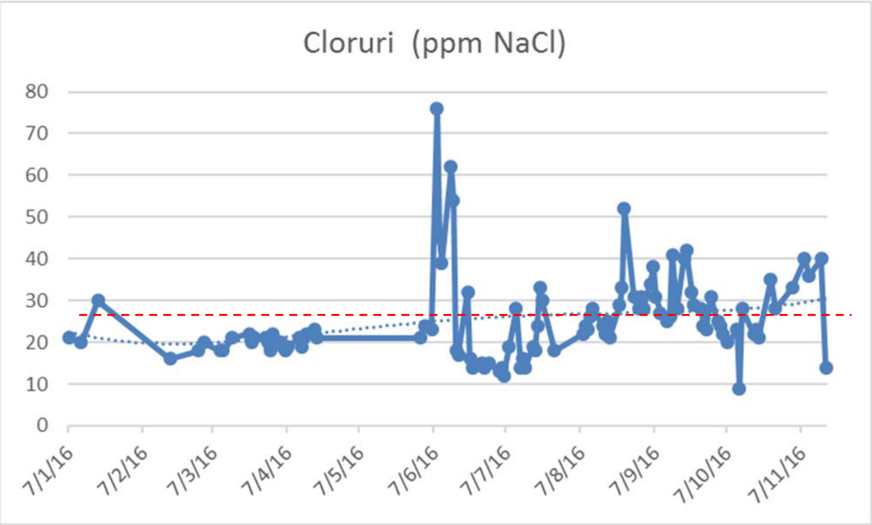


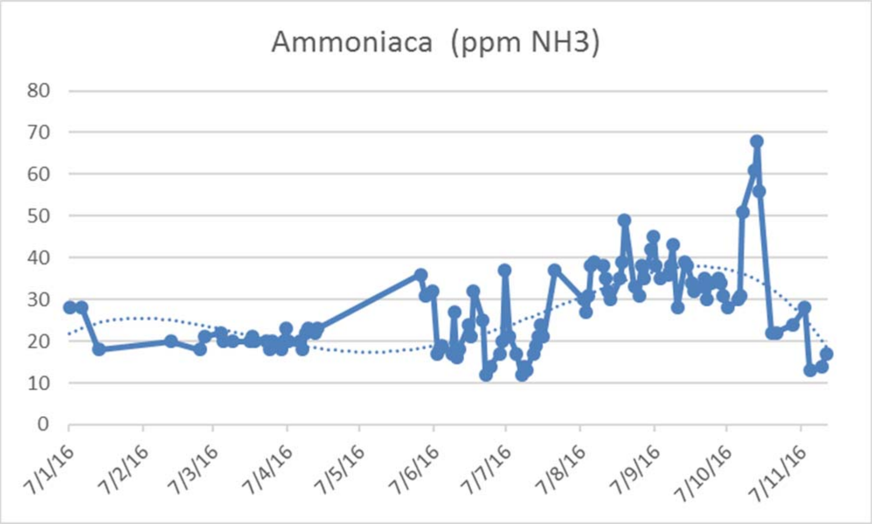
Zona del fascio tubiero interessata dalle forature

pH, Chlorides and NH_3 in the OVHD accumulator

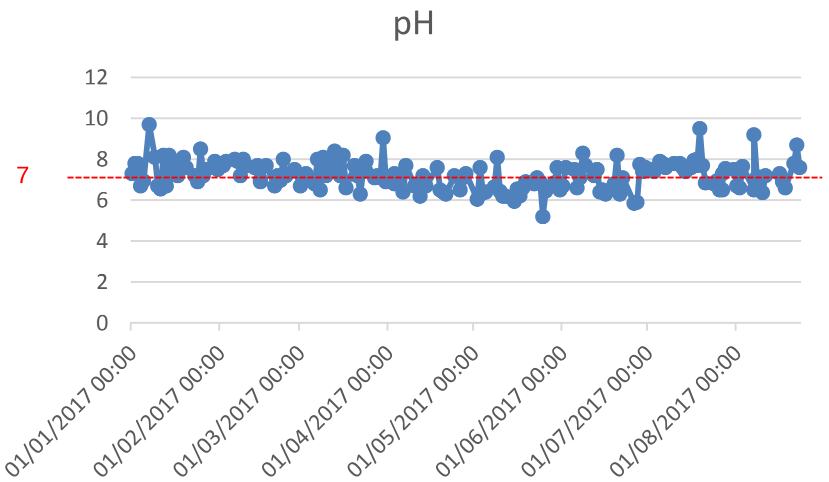


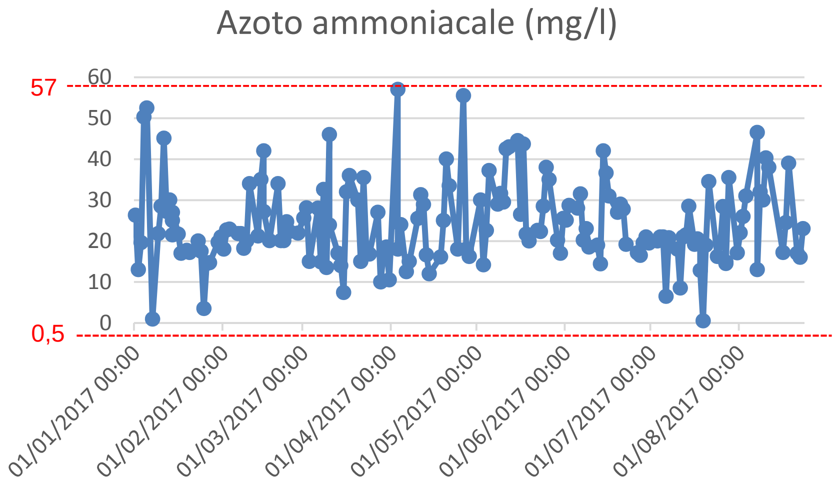
Usual limits

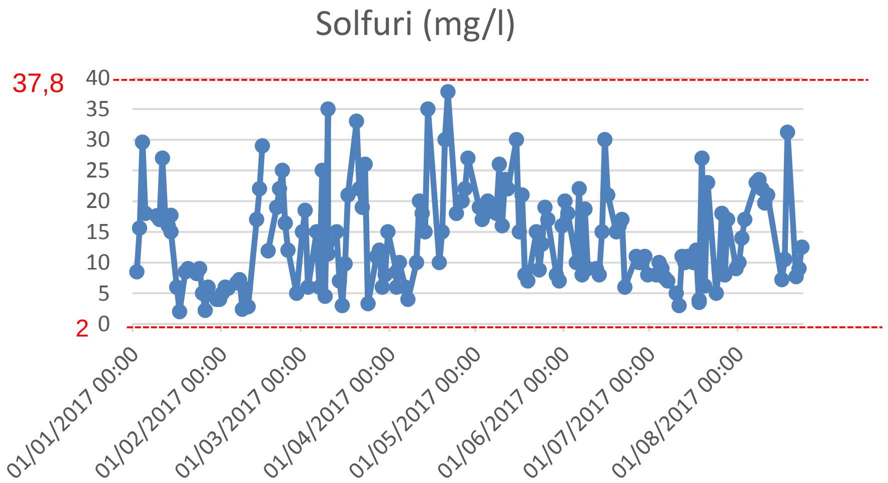




pH, NH_3 and sulfides of SWS water for injection

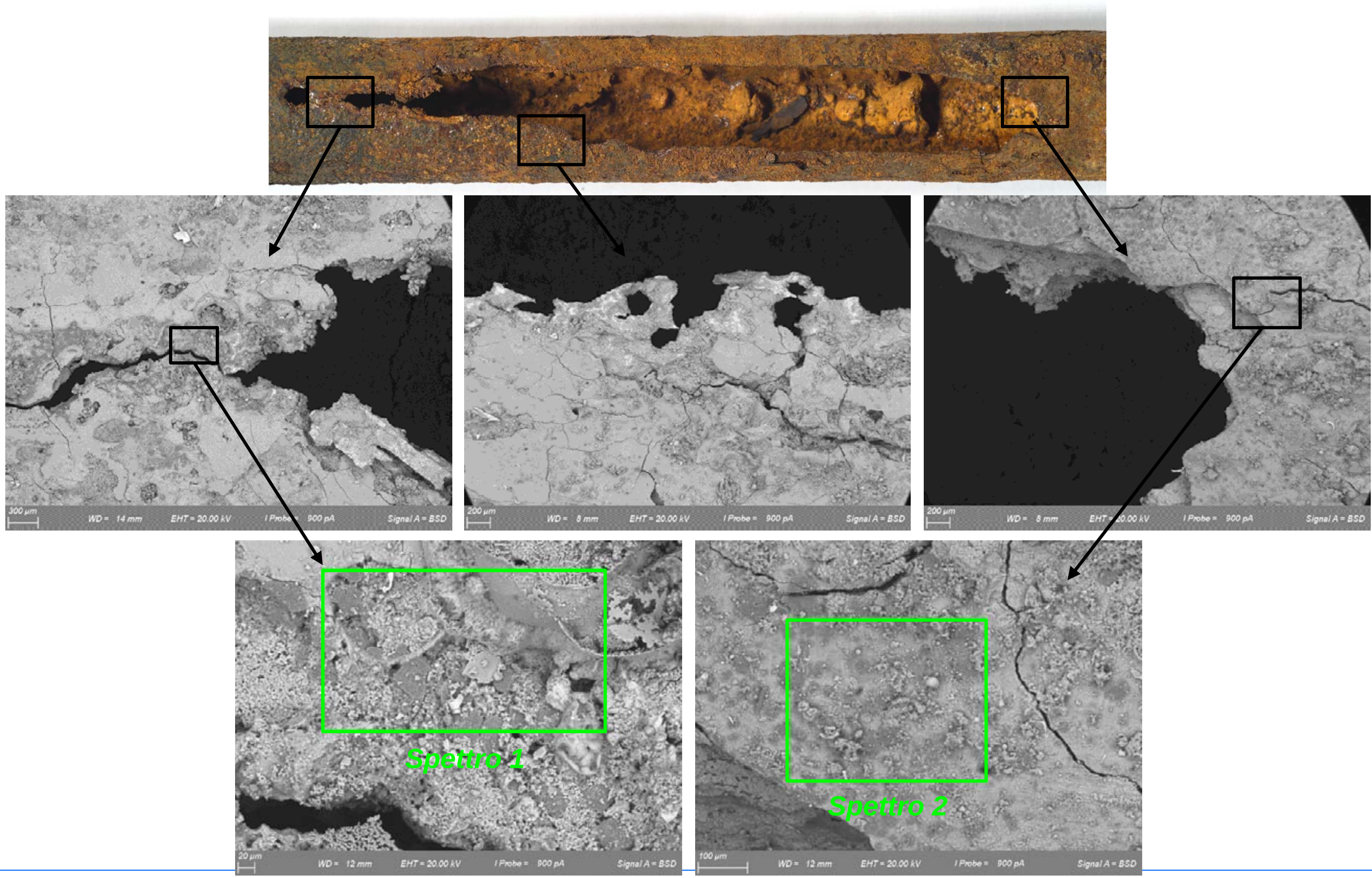




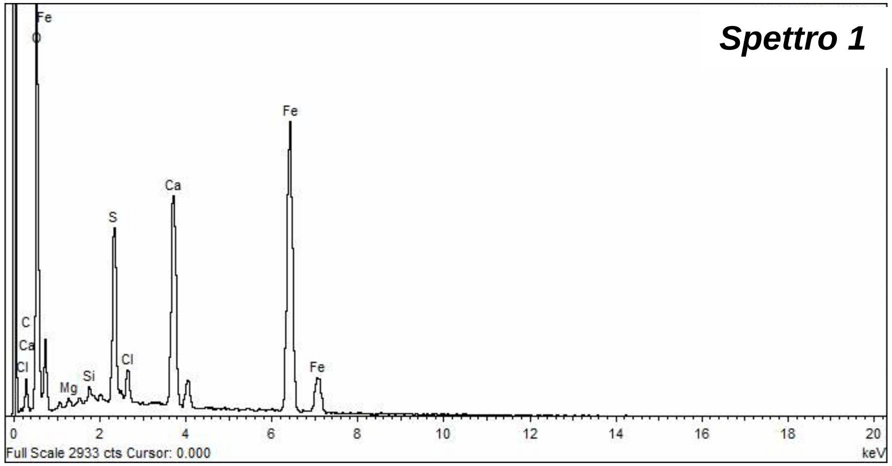


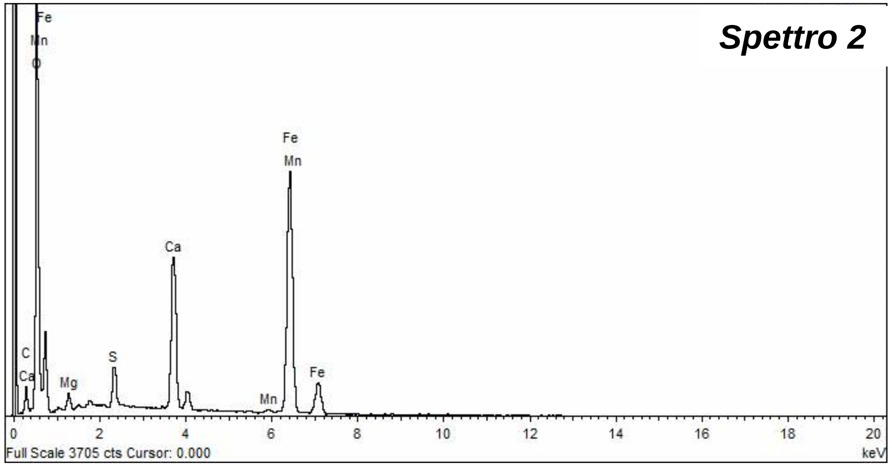
Detail of corrosion

SEM Examination

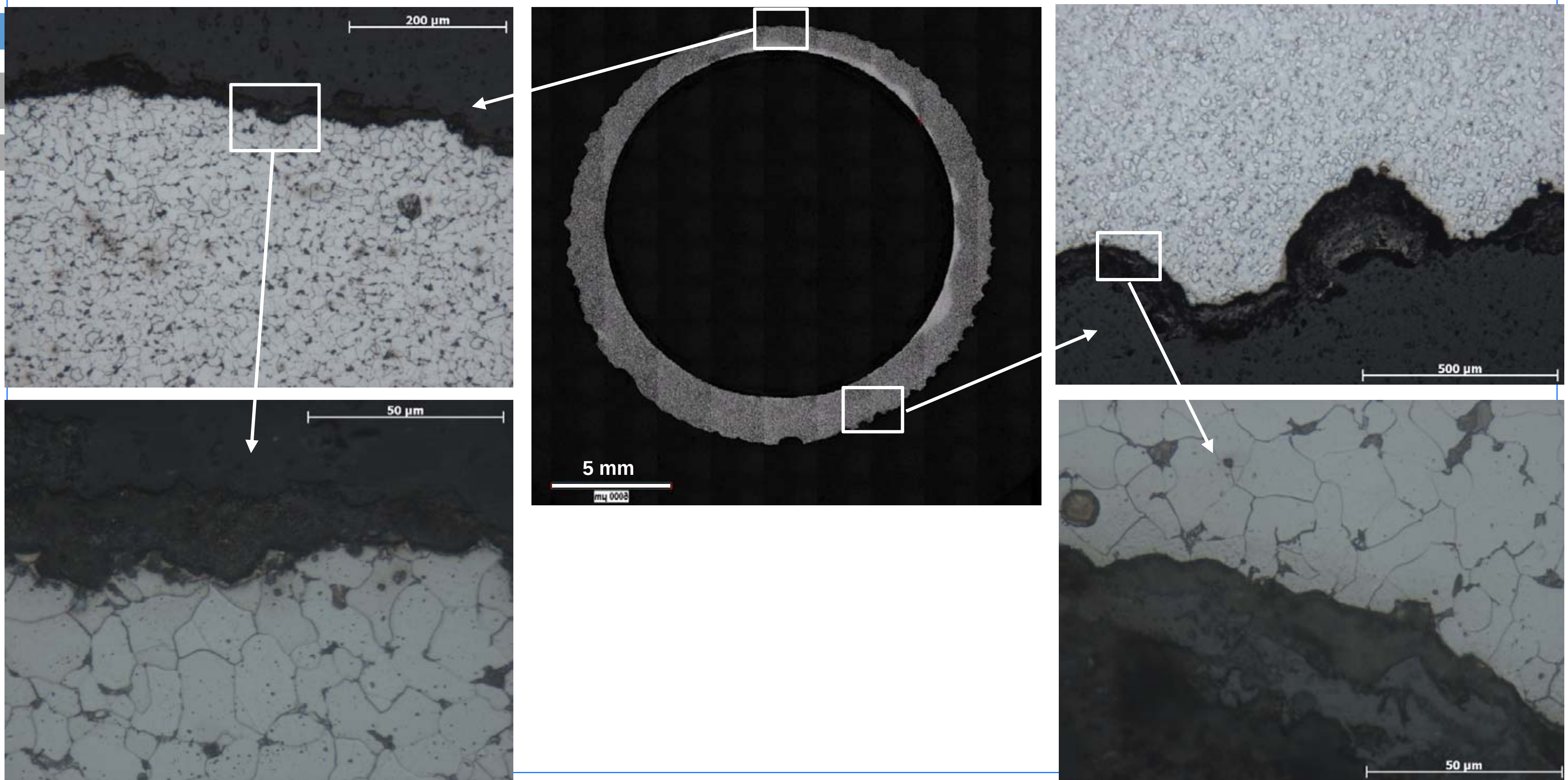


EDS Analysis on external surface

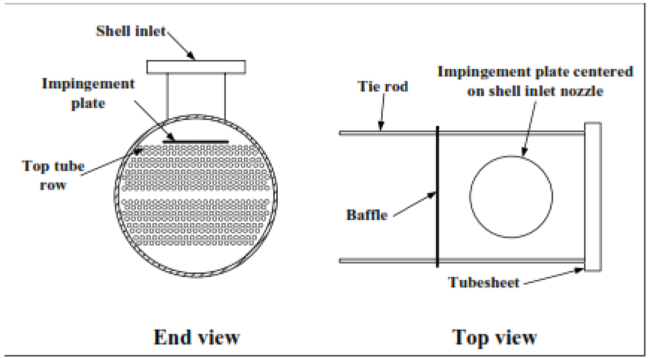




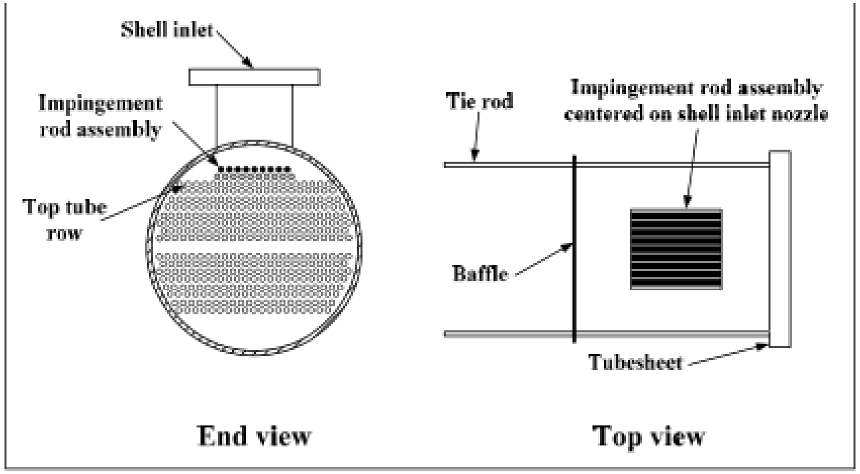
Section of a corroded tube



- Actual configuration-> Impingement plate itself can cause a restriction -> not sufficient clearance



- Better configuration-> Sacrificial solid rods (also possible to increase nozzle diameter)

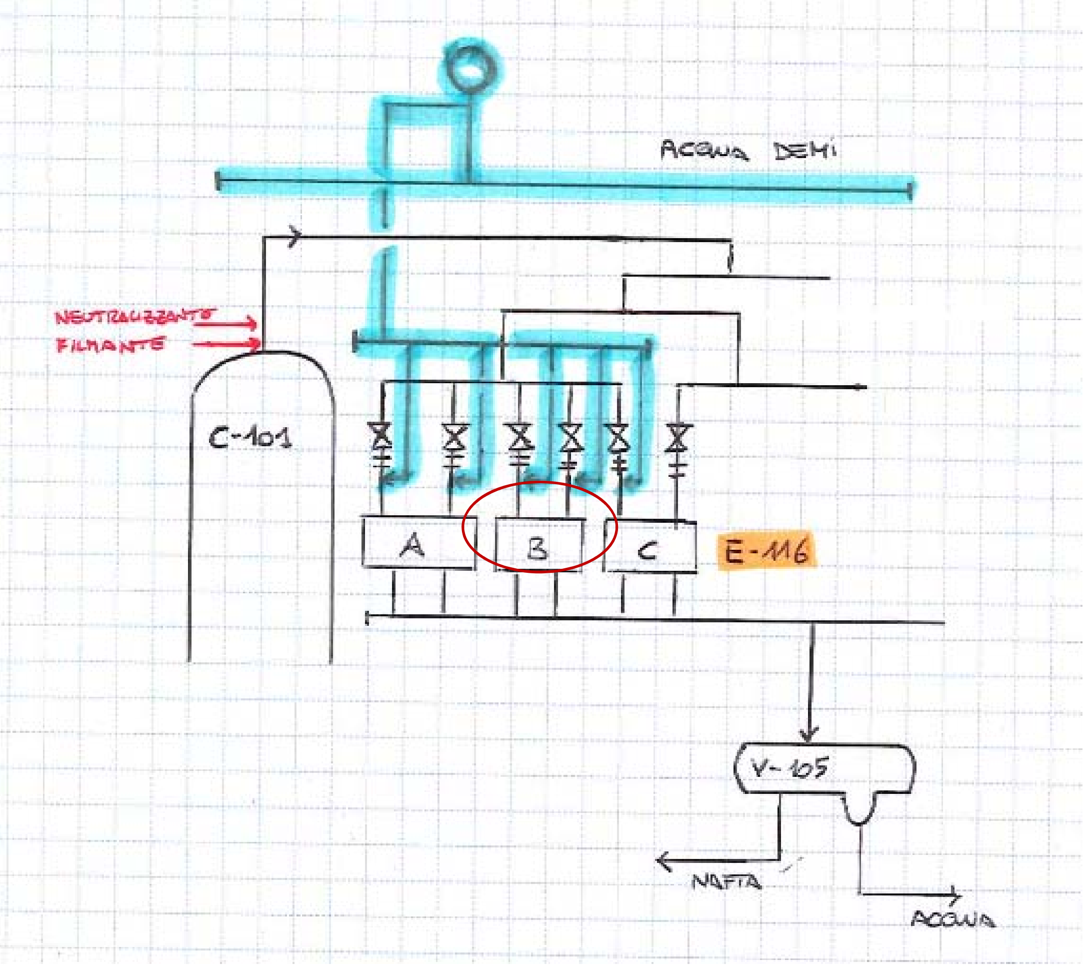


- ***CONTROL INJECTION RATE AND QUALITY OF WASHING WATER!***

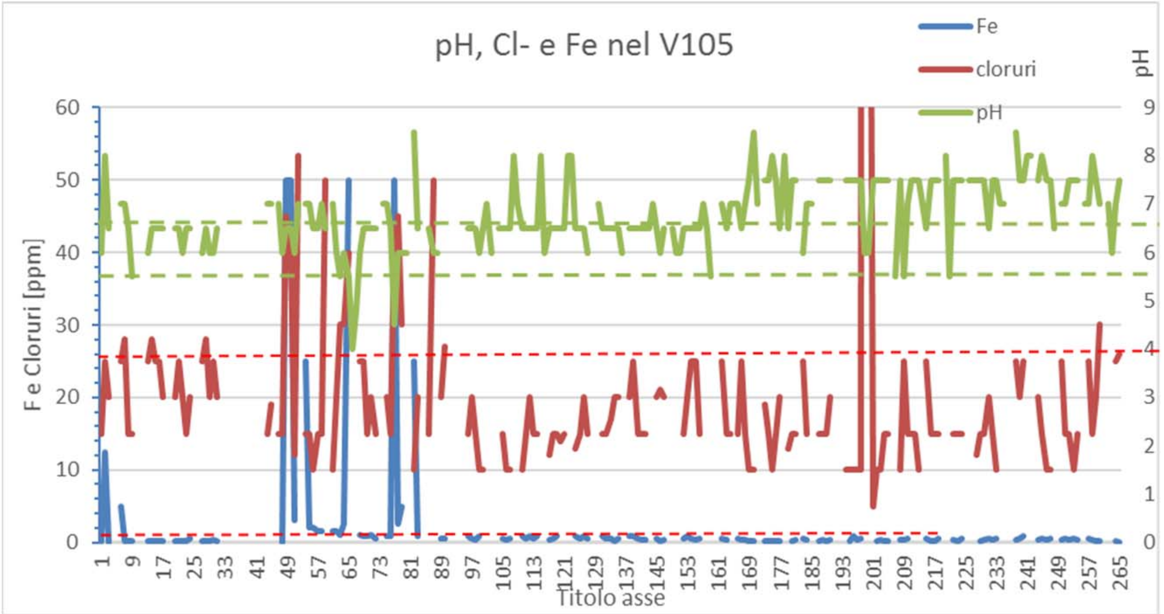
CASE HISTORY #2

- Overhead condenser CDU unit (AIR COOLER)
- Corrosion phenomena of Plate at outlet section (flow discharge of relevant tubes)
- Water washing implemented on the vapour line at each AC bank
- Water used -> demineralized BFW (not deaerated)
- Mixed metallurgy for tubes in different banks (duplex + CS)
- Injection of neutralizer (MEA +MOPA) and inhibitor on the vapour line

Scheme of injection point



pH, Chlorides and Iron in the OVHD accumulator

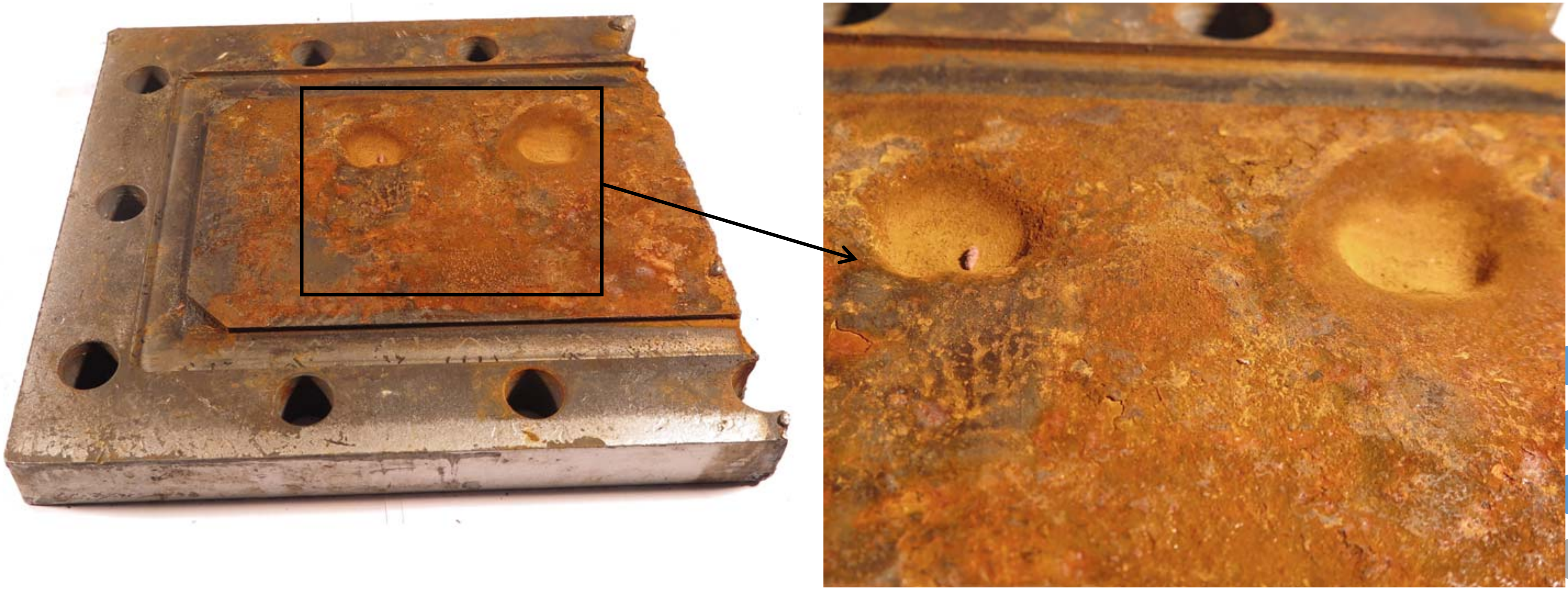


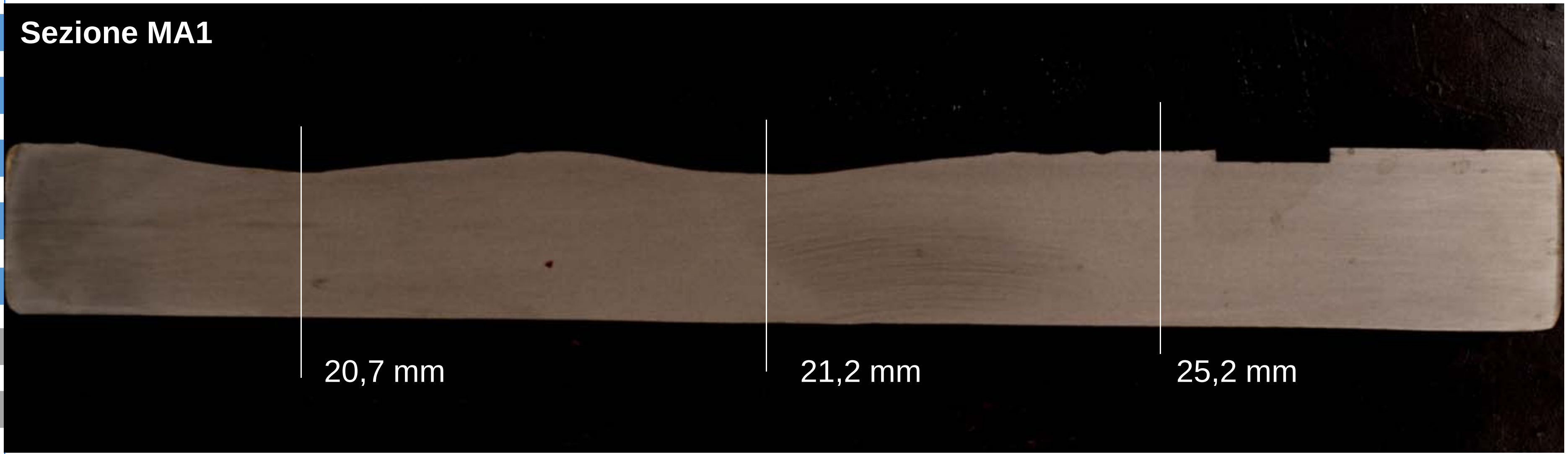
Other issues with the air-coolers

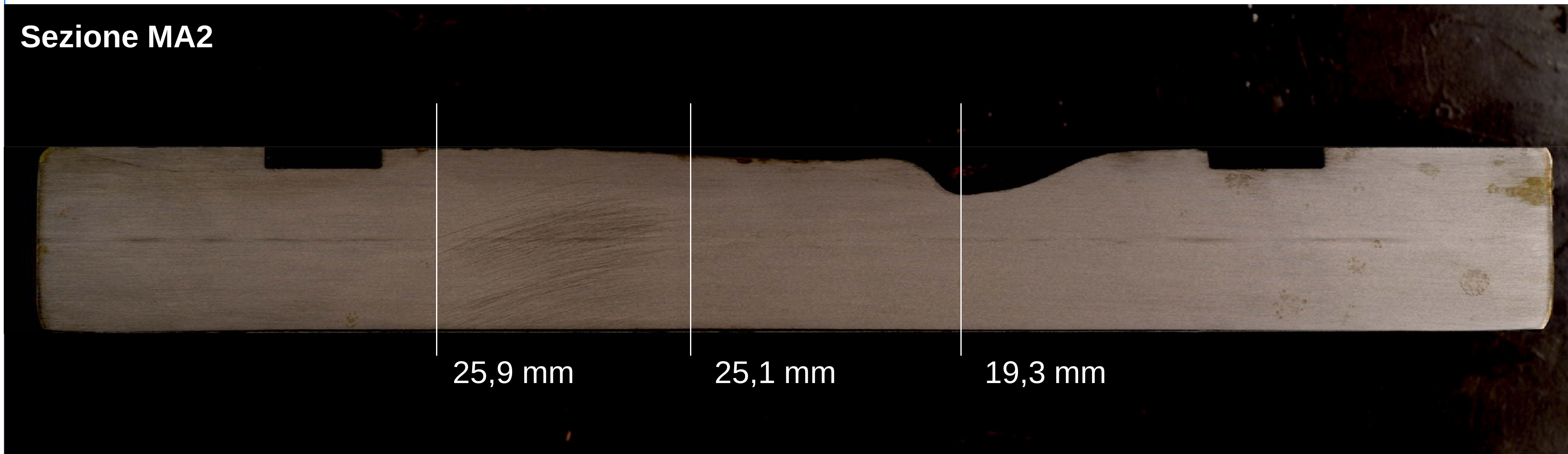
Grooving corrosion on the tube-sheet at outlet of tubes (only with SS tubes, no with CS tubes)

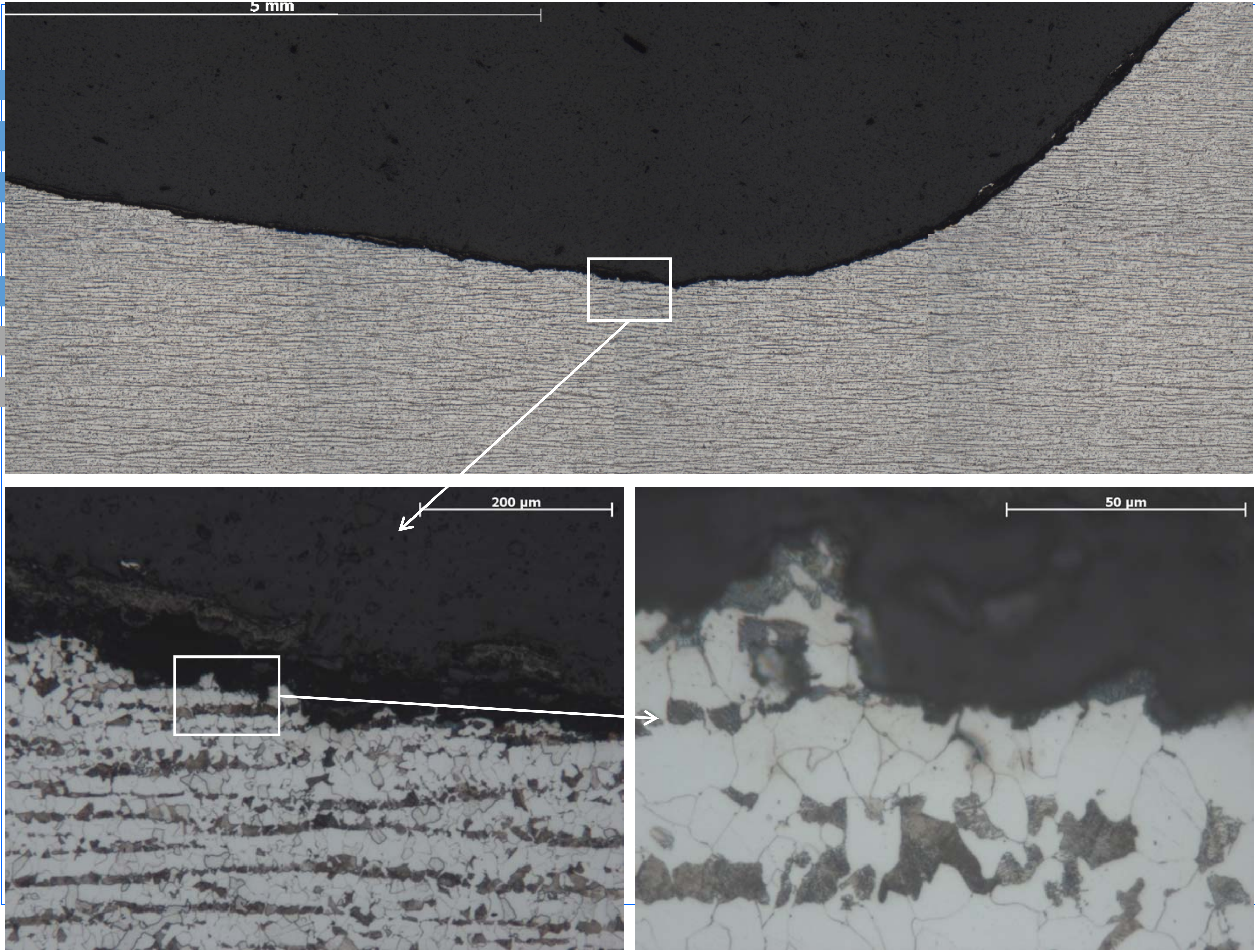
Organic fouling at AC inlet Box (asphaltenes rich)

Detail of corrosion




Sezione MA1
20,7 mm
21,2 mm
25,2 mm


Sezione MA2
25,9 mm
25,1 mm
19,3 mm


5 mm
200 µm
50 µm

DISCUSSION

- Heavy impingement corrosion of plate.
- Organic fouling plug some tubes -> increased velocity in plug free tubes
- WW -> BFW with 5 ppm O_2 -> not deaerated

- ***CONTROL INJECTION RATE, INJECTION POINT AND QUALITY OF WASHING WATER, ALSO CONSIDERING HEAVY ORGANIC FOULING (PLUGGUNG OF SOME TUBES)***

Appendix 7

Advancement of the development of a methodology to characterize Stress Relaxation Cracking

(M. Monnot)

Advancement of our development of a methodology to characterize Stress Relaxing Cracking on welded stainless steels

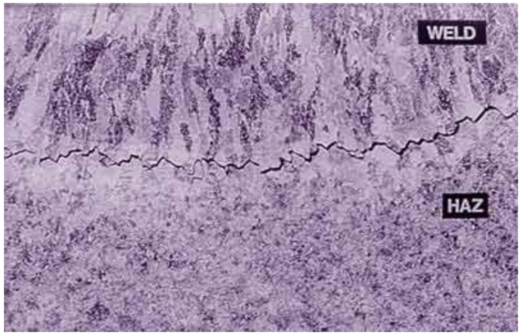
03/05/2018

Martin MONNOT

Introduction

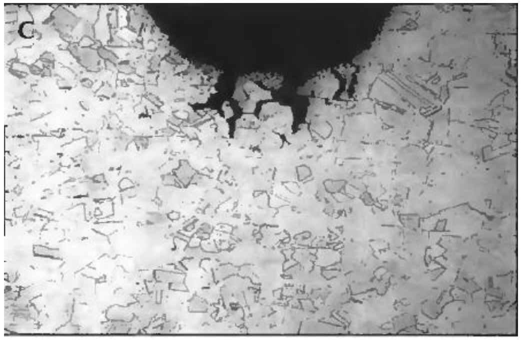
- Reheat Cracking and Stress Relaxation Cracking are damage mechanisms occurring in equipments from many industries combining both high stresses and high temperatures.

- **Reheat Cracking (RHC)** is commonly associated to Carbon & CrMo(V) steels, and is generally a problem occurring during fabrication (PWHT after welding) of the equipment



Example of a RHC Crack in a HAZ of a CrMoV low alloy steel

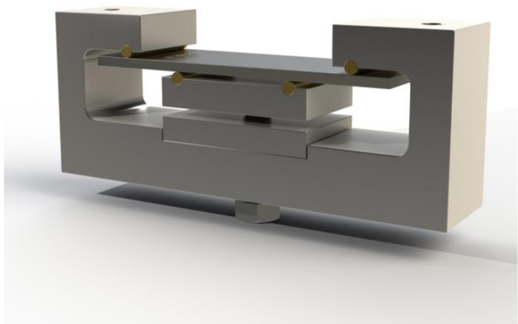
- **Stress Relaxation Cracking (SRC)** is commonly associated to austenitic alloys, such as 300 series and nickel base alloys occurring during service of the equipments.

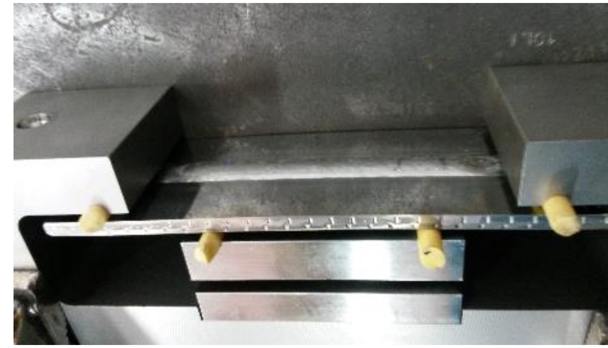


Example of a SRC Crack in a HAZ of a 347H austenitic stainless steel

First methodology

- 4 points bending test:
  - Welded samples (HAZ) with seam
  - Dimensions: 140 x 40 x 4 mm





Grade	Stress applied	Deflection (mm)	Temperature (° C)	Holding time	Cracks number
304LN	>> 120% YS	5	650	500 h	No cracks
			600		
		3	600		
347H	>> 120% YS	5	650		
			600		

Second methodology

ArcelorMittal

- U-bend test:
  - Welded samples (HAZ) with seam
  - Dimensions: 140 x 40 x 4 mm

Grade	Temperature (° C)	Holding time	Cracks number
304H	600	500 h	No cracks
	650		
347H	600		
	650		
	700		

Weld in transverse direction

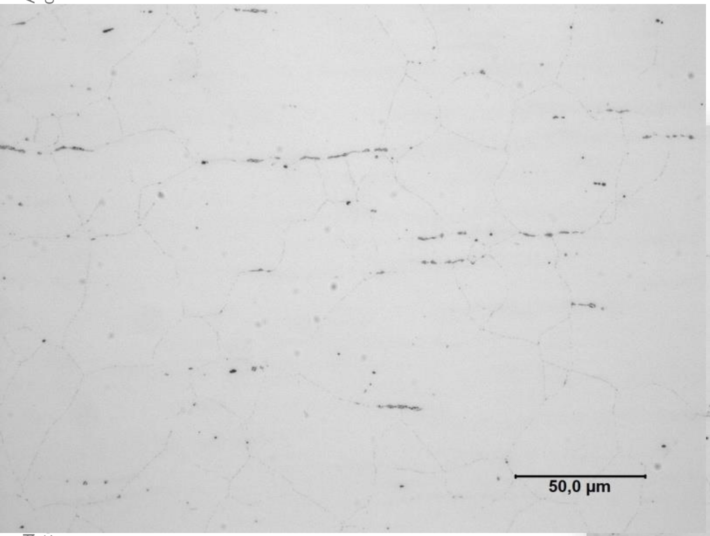
Weld in longitudinal direction

➢ Is the metallurgical state adequate to initiate SRC?

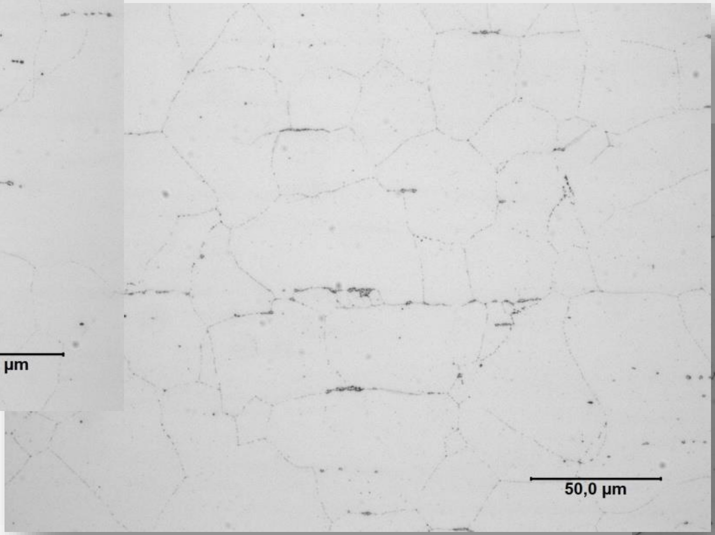
Microstructure after ageing

- Precipitation state after ageing under the weld seam

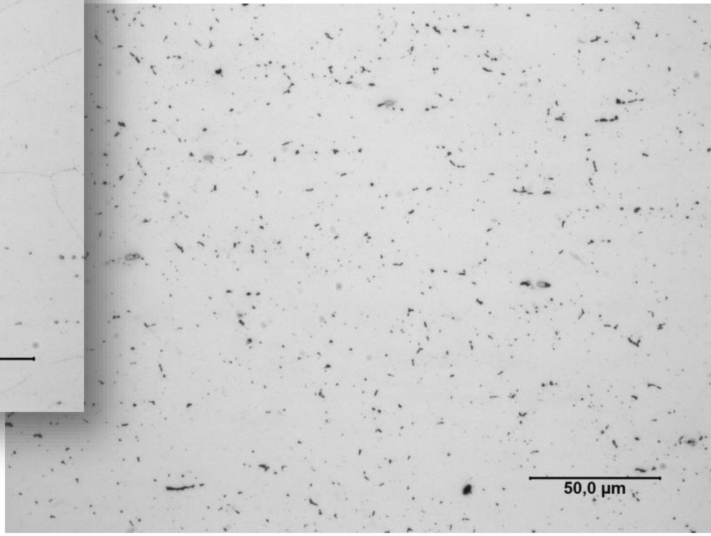
600ºC/500h



650ºC/500h



700ºC/500h

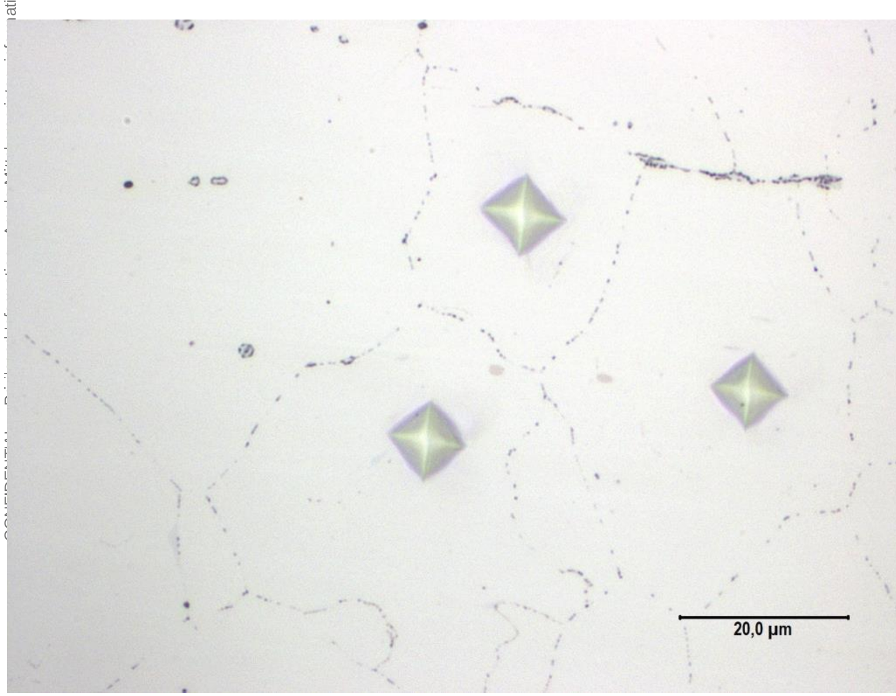


➢ Intergranular precipitation first, transgranular precipitation then

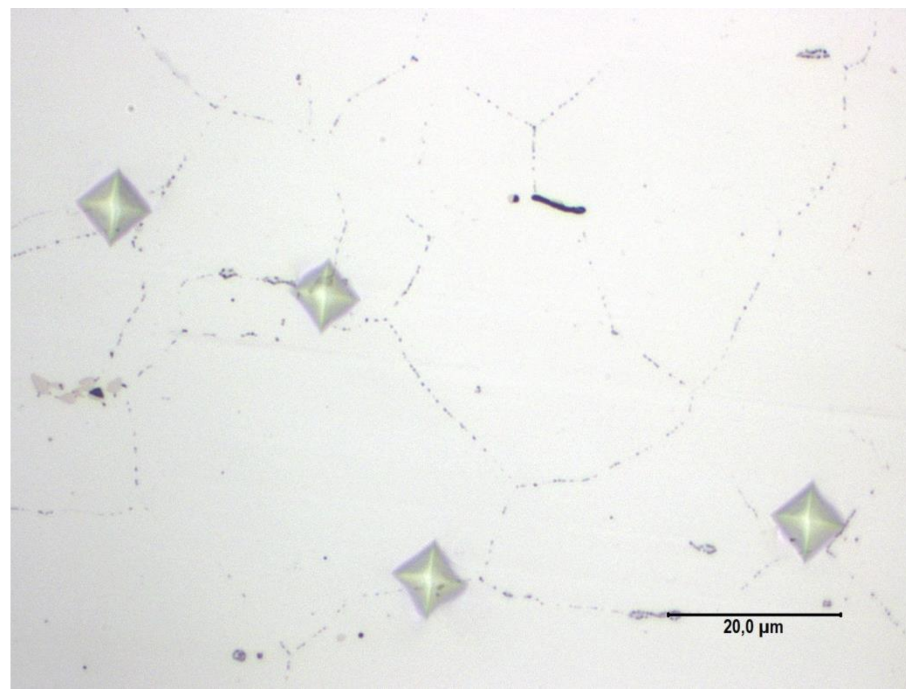
Influence of precipitation on hardness

- Use of micro hardness instrument (weight of 0.010 kg_f)

Mark in grain

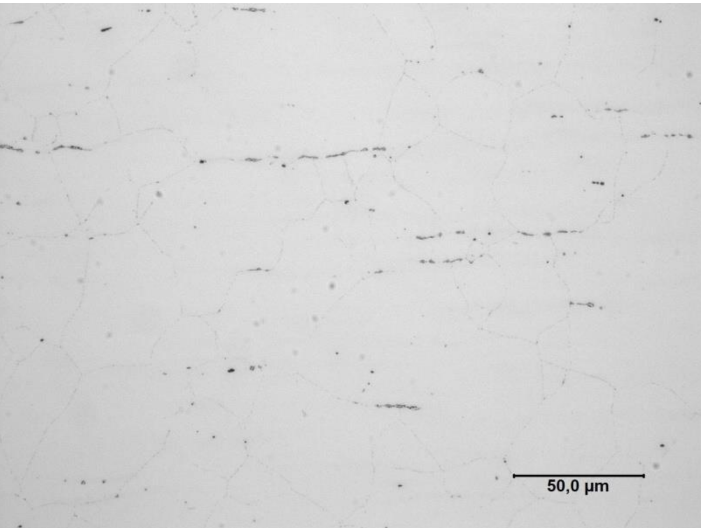


Mark at grain boundary



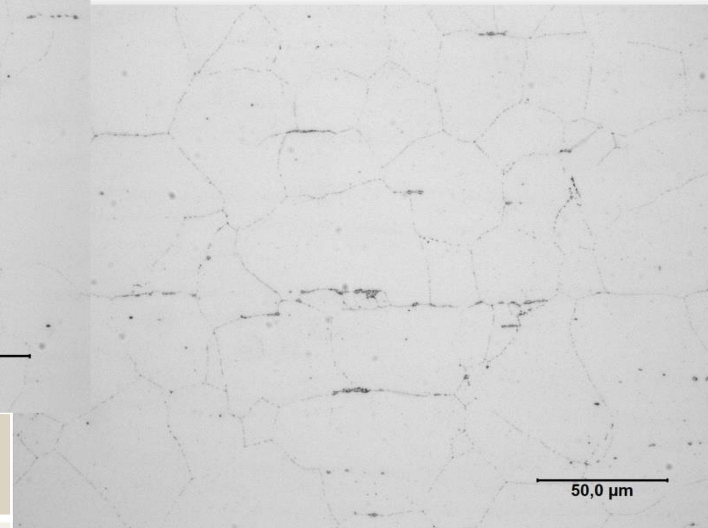
Hardness after ageing

600ºC/500h



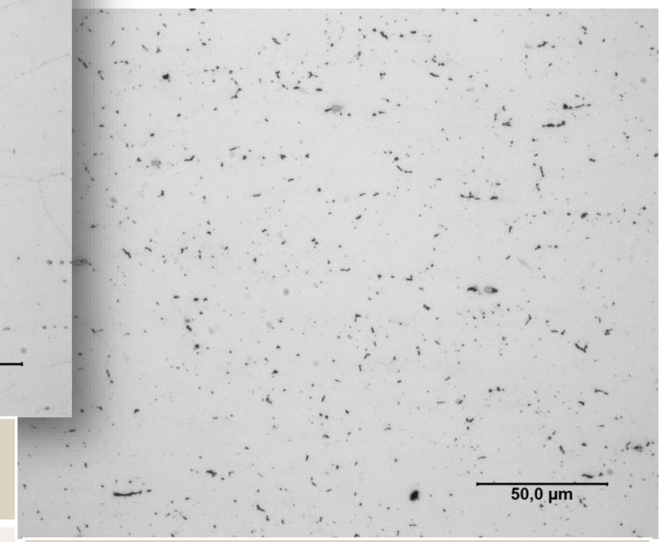
Hardness HV	
In grain	At grain boundary
198	233

650ºC/500h



Hardness HV	
In grain	At grain boundary
188	216

700ºC/500h



Hardness HV	
In grain	At grain boundary
173	181

- Decrease of hardness with differences between grain and grain boundary

Third methodology

- No cracks on previous set-up, probably because of :
  - Thickness of plates: 4 mm is too thin
  - Welding process: weld seam induced HAZ too small
  - Precipitation and stress relaxation kinetics mismatch

✓ U-bend set-up : strain around 10%
✓ Specimen 15 mm thick
✓ Welding process : GMAW through all thickness
✓ Sensitization before straining

On going tests in order to optimize sensitization before straining

THANK YOU FOR YOUR ATTENTION !

Please feel free to share questions or remarks

Dr. Martin Monnot
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Appendix 8

Non-destructive inspection through insulated systems

(B. White)

Non-Destructive Inspection Through Insulated Systems

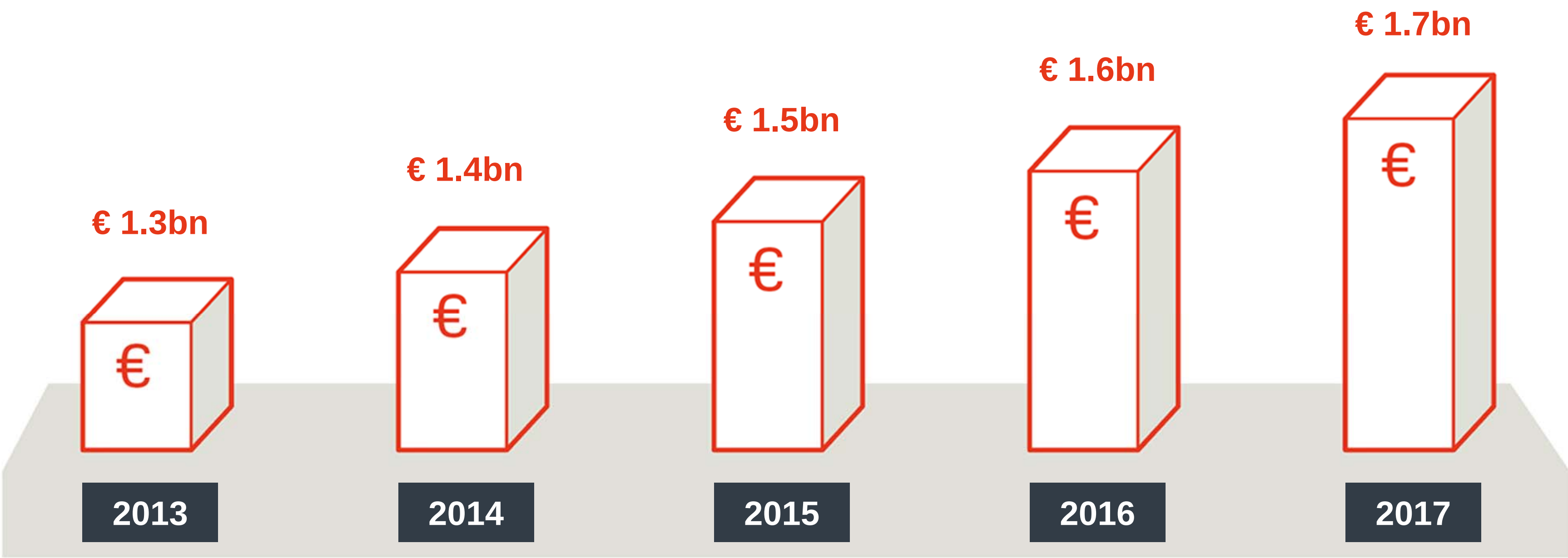
Tenaris University, Dalmine, May 3rd 2018

Calum White

KAEFER

KAEFER worldwide

Our turnover in Euros



KAEFER

Our diverse and dedicated team

Accreditation

UKAS
UNITED KINGDOM ACCREDITATION SERVICE

INSPECTION BODY
No. 8689

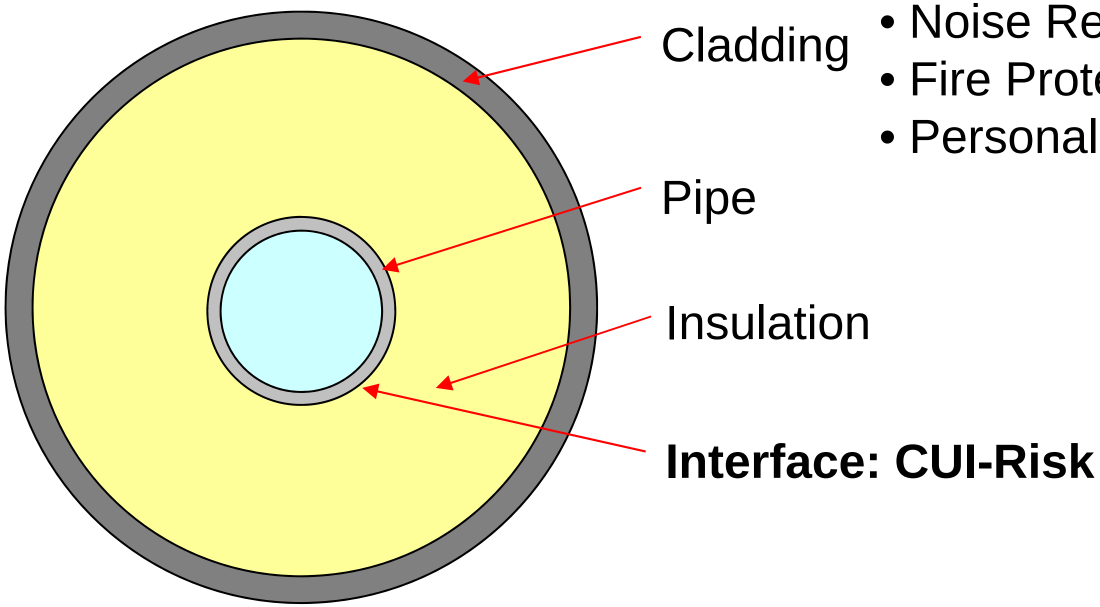
DNV·GL

Certificate No:
AOSS0000AKZ

TWI

THE
BRITISH
INSTITUTE of
NON-DESTRUCTIVE
TESTING

Typical Insulated Pipe



Reasons for Insulation:
- Process Control
- Freeze Protection
- Energy Efficiency
- Noise Reduction
- Fire Protection
- Personal Protection

Corrosion Under Insulation (CUI)

How CUI is caused

> In order to have CUI, you **must have an insulation system** installed on a pipeline or vessel

> Water penetration allows oxygen corrosion to occur.
This can happen due to:
Rain water
Deluge systems
Process liquid spillages
Condensation

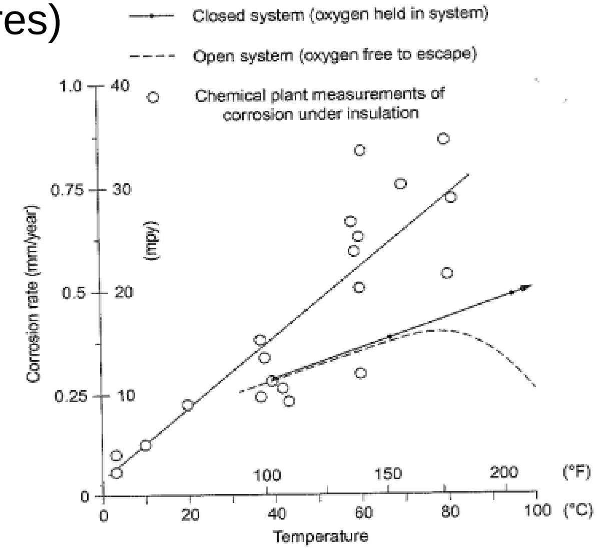
> Further contamination, primarily **chlorides and sulfates** from the environment or insulation can speed up the process dramatically

Corrosion Under Insulation (CUI)

> <u>CUI is generally categorised into one of four categories:</u>

1. Low temperature (cold or cryogenic conditions)
2. Sweating service (operating below the dew point)
3. High temperature (above ambient temperatures)
4. Cyclic temperature (alternating)

> Special consideration regarding dew points is required depending on location



> Figure 1 – EFC No. 55: CUI Guidelines

KAEFER

CUI – The Problem

> Hidden threat due to insulation & cladding
> No form of insulation is immune
> Inspection technology difficult, or at least slow and very costly
> >80% CUI occurrences in piping
> **40 to 60%** of pipe maintenance costs are caused by CUI
> Approximately **10%** of the total maintenance budget is spent repairing damage from CUI
> NACE SP0198-2010 & EFC 55: CUI can occur up to 175°C
> CUI rates ~20 times greater than atmospheric corrosion rates may occur

Carbon steel:
-4 °C to + 175 °C: Risk of CUI
(highest risk area: +60 °C to +120 °C)

Stainless steel:
+50 °C to +175 °C

Non-Destructive Testing (NDT)

> **Conventional Techniques**

> Volumetric:
> Ultrasonic Testing (UT)
> Radiographic Testing (RT)

> Surface:
> Magnetic Particle Testing (MT)
> Dye Penetrant Testing (PT)
> Eddy Current Testing (ET)
> Visual Testing (VT)

New Technologies in NDT

> **CUI Inspection – Inspect without removing insulation means considerable savings for the owner**

> **OpenVision**

> Portable fluoroscopic (RTR) low voltage X-ray inspection tool

> Capable of inspecting through cladding and insulation

> Can image the pipe wall surface, showing areas of potential CUI or contaminated insulation

> **Eddyfi Lyft**

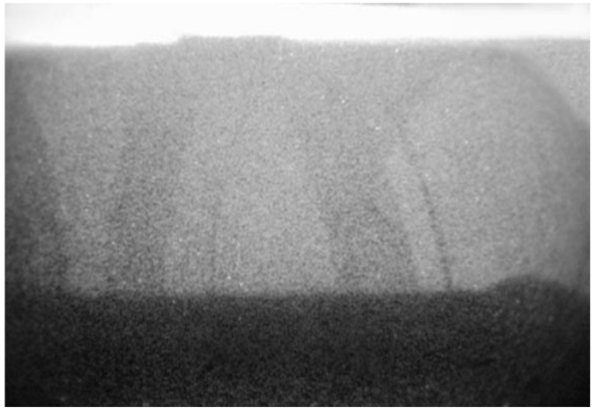
> Pulsed Eddy Current (PEC)

> Induces powerful magnetic force into the test item through cladding and insulation

> Can evaluate average remaining wall thickness over an area

OpenVision

> Handheld or mounted low voltage X-ray scanning device



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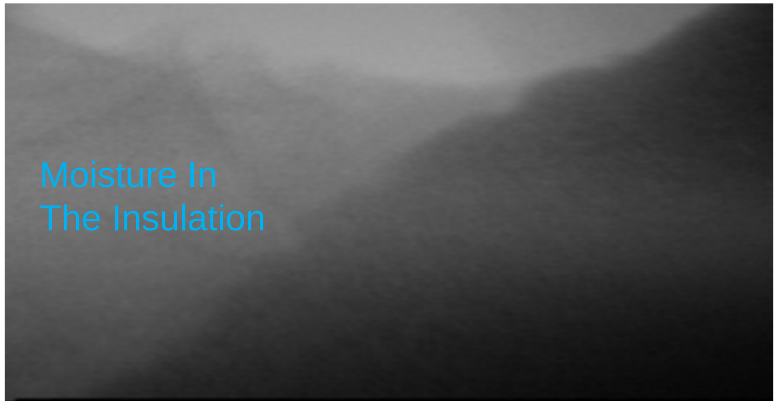
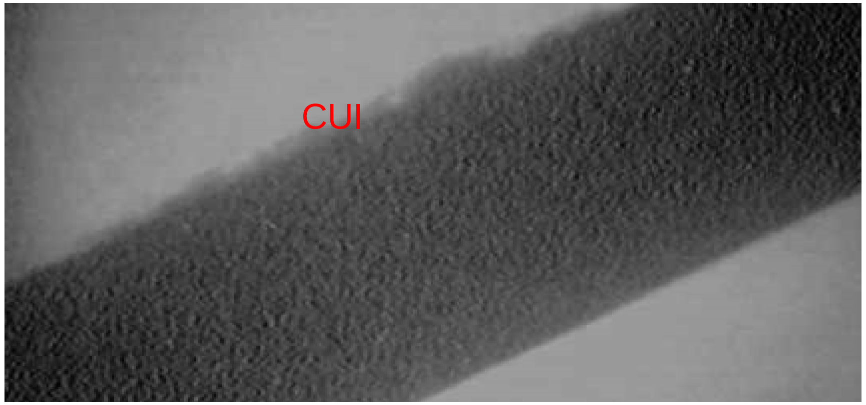
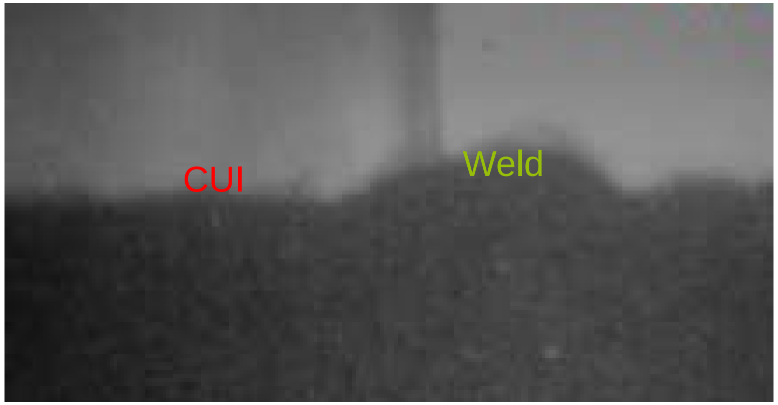
What does CUI look like?





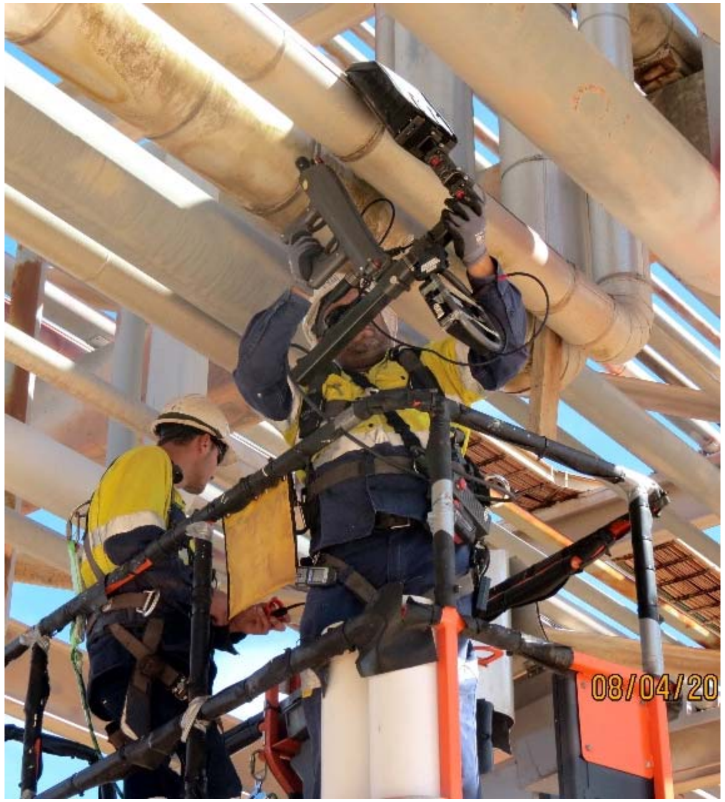


KAEFER

OpenVision

Main Benefits

> Real time data acquisition
> Capable of inspecting through most insulation and cladding
> Also capable of locating welds
> Fairly low radiation intensity
> No isotope (can be turned off)
> Performed in a two man team
> Roaming safety barriers reduce exclusion site zone



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OpenVision

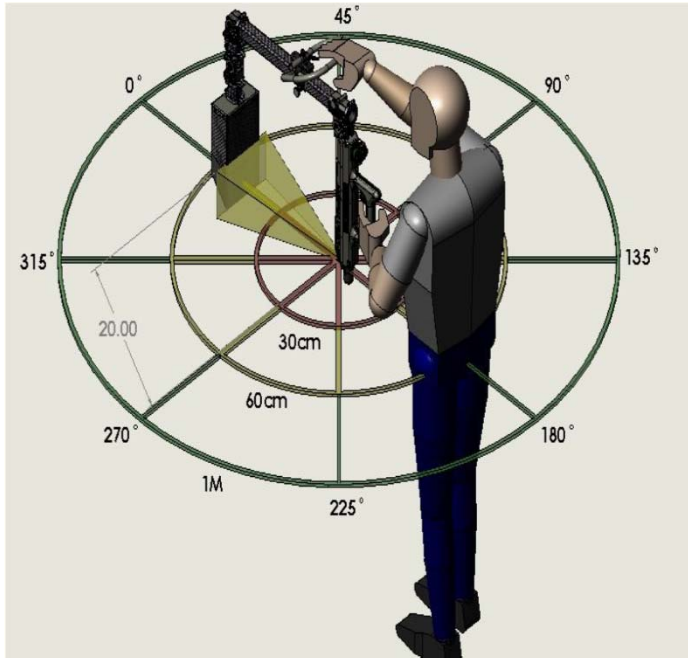
Main Limitations

> **<u>Radiation</u> – Although relatively low energy, there is still a radiation danger. Depending on energy used, differing exclusion zones may be recommended**

> **Requires the use of classified workers**

> **High operator dependency (working on automated analysis)**

> **Access restrictions – Require 360° access for full coverage**



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OpenVision in Action

KAEFER

Eddyfi Lyft

> Pulse Eddy Current (PEC) System

KAEFER

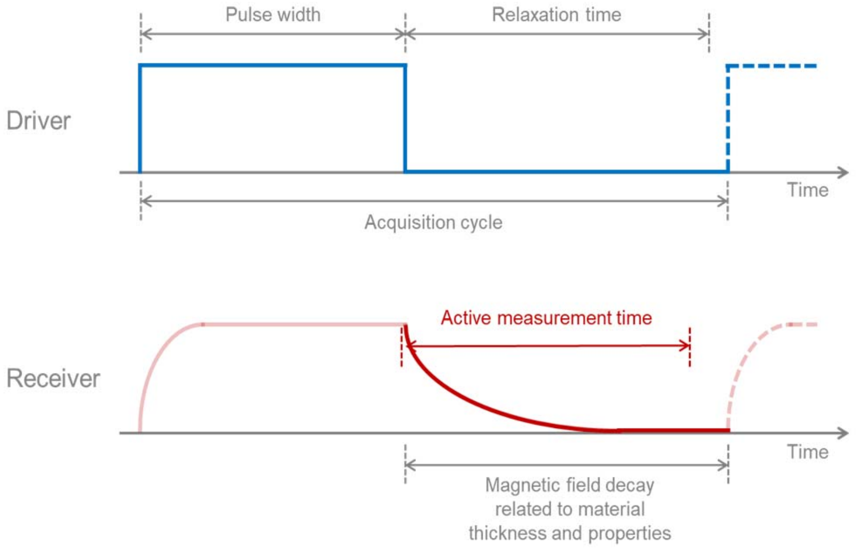
Eddyfi Lyft

> How it works

1. Emission phase (the pulse): Probe injects magnetic fields that penetrate and stabilise in the component thickness.

2. Cut-off phase: Magnetic field emission is stopped abruptly, which induces strong eddy currents in the component.

3. Reception phase: Receiver measures the decay of the eddy currents as they diffuse into the material thickness.



KAEFER

Eddyfi Lyft

> **Main Benefits**

> Can detect remaining wall thickness of material through insulation and cladding, including galvanised cladding

> Very portable equipment

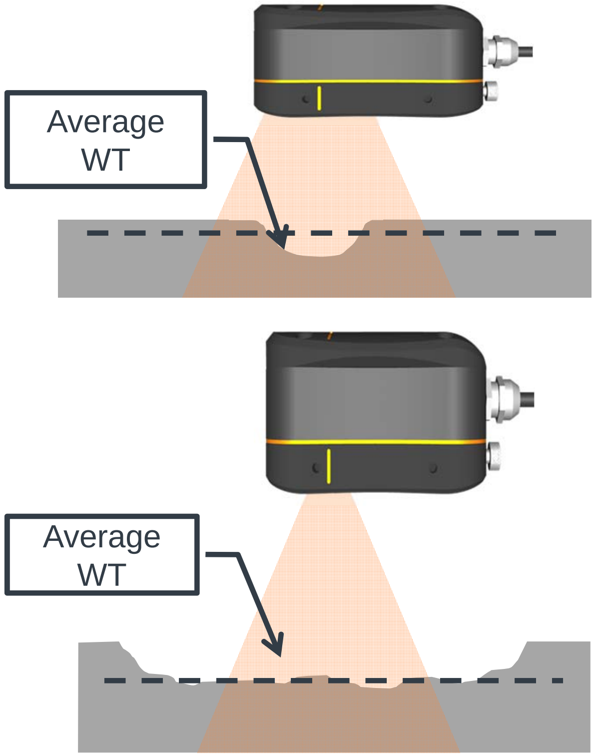
> Very safe, zero exclusion zone required

> Can be performed online

Eddyfi Lyft

> **Main Limitations**

> Screening tool, provides relative measurement
> Unable to discriminate near-side and far-side defects
> Impossible to detect small pitting
> Undersizes flaws smaller than the averaging area of the probe
> Edge effect near metallic structures
> Impossible to detect through hole defects



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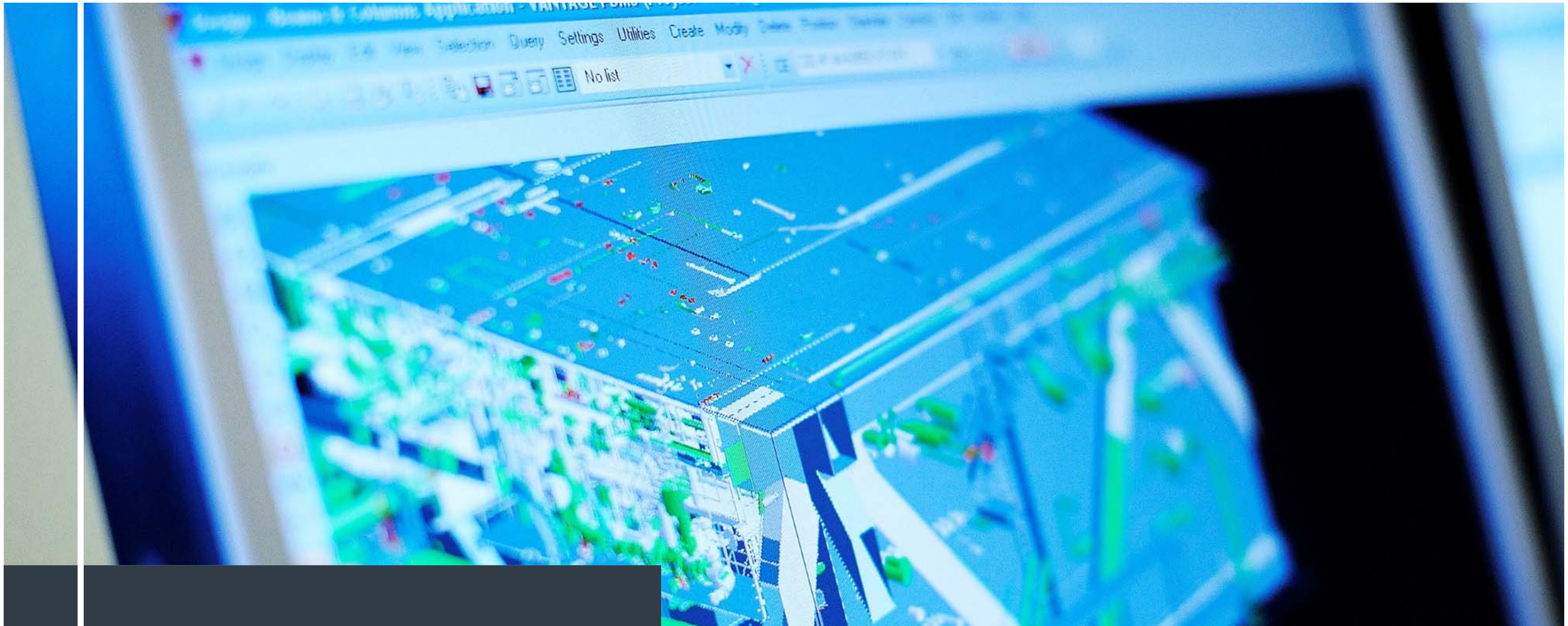

What KAEFER can achieve

Holistic CUI Package

KAEFER is working towards offering a full inspection package, tailored to clients‘ needs.

> 1. Visual inspection to identify areas of high risk
> 2. Screening technique using site suitable method (OpenVision or PEC) to determine presence of CUI
> 3. Deinsulation
> 4. Inspection (VT, UT)
> 5. Reinsulation

KAEFER

Current Operations

KAEFER is providing a CUI inspection service for clients in Australia:

- Operations have been progressing since 2016
- Very positive feedback from clients

- *We want to acknowledge the successful outcomes from the KIPS "open vision" work completed in A station units in recent months. The inspections identified corroded pipes and failed hangers which have since been replaced, mitigating potential safety breaches as well as minimising risk of unplanned outages. In addition, KIPS also identified corrosion at locations where we considered to be least susceptible to CUI. We have now incorporated the KIPS open vision method in our inspection strategies for pressure piping and hangers, and now aiming to utilise rope access.*
  Many thanks.

  Adrian Fidel

  Mechanical Engineer - Boilers, Gas & Renewables Engineering

  AGL Torrens

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THE BRITISH INSTITUTE of NON-DESTRUCTIVE TESTING

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Appendix 9

Sulfide Stress Corrosion Cracking on dissimilar 625/carbon steel welds

(M. De Marco)

ISTITUTO ITALIANO DELLA SALDATURA

Il Gruppo

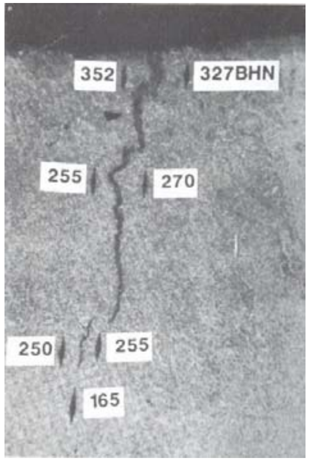
ISTITUTO ITALIANO DELLA SALDATURA

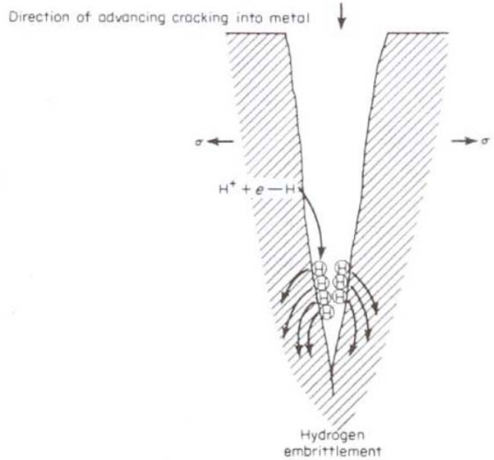
SSC cracking of a dissimilar welding in gas piping

M. De Marco

INTRODUCTION

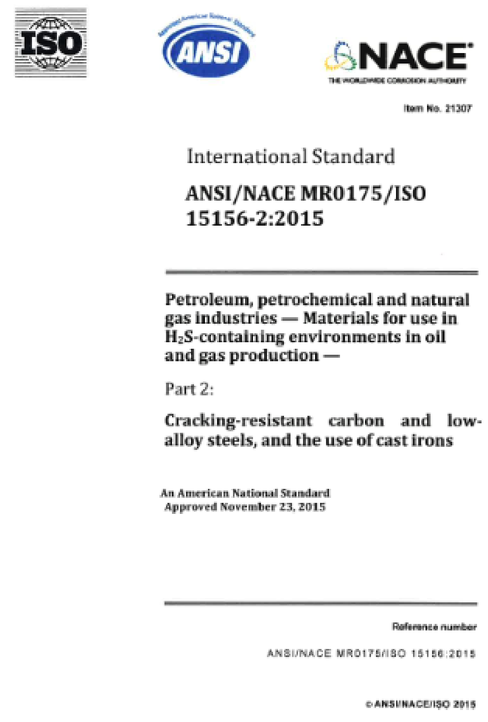
- CRAs are widely applied in Oil& Gas industry in order to guarantee corrosion and SCC resistance in very harsh environments (H_2S, CO_2, Cl^-, MIC, various organic and inorganic acids…).
  - Standard and Special stainless steels
  - Nickel alloys
  - Copper alloys
  - Titanium alloys
  - …
- Sulfide Stress Cracking (SSC) is one of the most insidious damage mechanisms that must be considered during design, construction and operation of components in O&G industry.





CASE HISTORY #1

- ISO15156/NACE MR0175 parts 2 and 3 cover respectively the requisitions to resist to SSC phenomena of Carbon/low alloy steels and CRA.
- EFC publications 16 and 17 cover respectively the requisitions to resist to SSC of Carbon/low alloy steels and CRA.
- Many end-users and engineering company specifications outhere


ISO ANSI NACE

THE WORLDWIDE CORROSION AUTHORITY

Item No. 21307

International Standard

ANSI/NACE MR0175/ISO 15156-2:2015

Petroleum, petrochemical and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production —

Part 2:

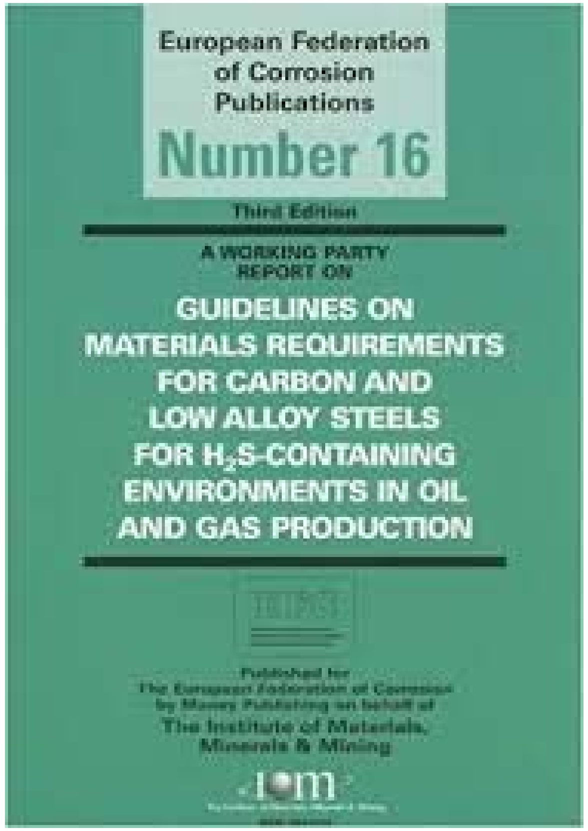
Cracking-resistant carbon and low-alloy steels, and the use of cast irons

An American National Standard
Approved November 23, 2015

Reference number

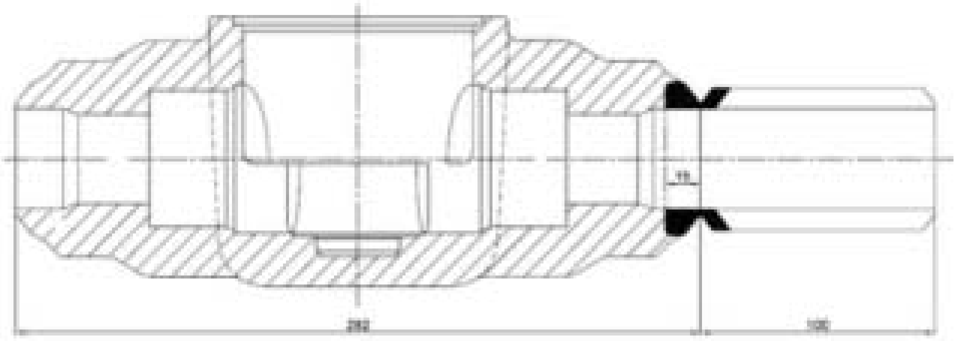
ANSI/NACE MR0175/ISO 15156:2015

© ANSI/NACE/ISO 2015



SSC failure case history

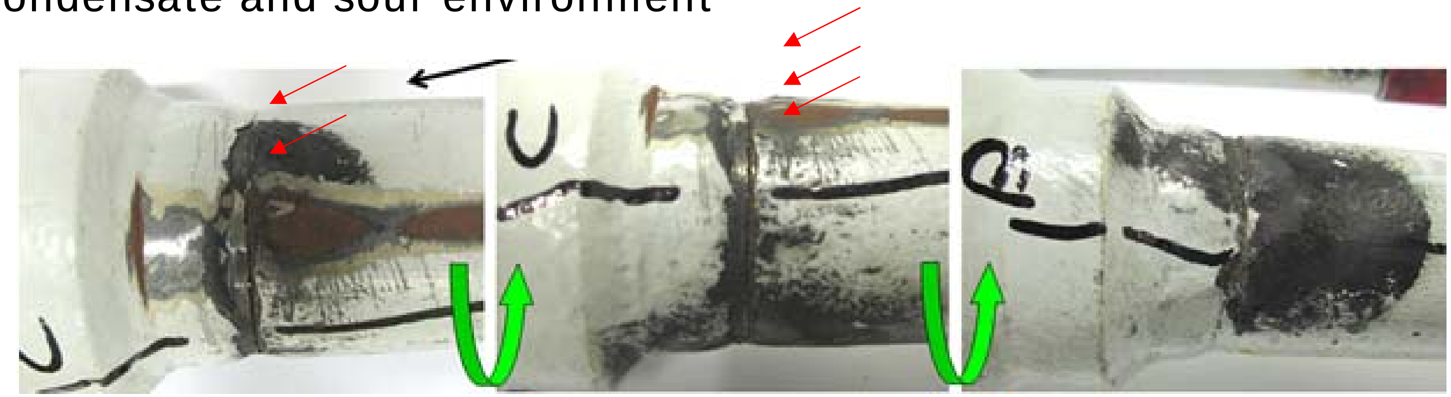
- Gas treating plants.
- 2" valve made of Carbon Steel (CS) welded to CS pipe.
- Operative conditions
  - T: 61 °C
  - P: 55,7 barg
  - H_2O: 0,37 % mol (close di dew point)
  - ppH_2S : 1,76 barg
- In order to avoid damage to non metallic components in the valve during PWHT (commonly applied on CS in sour service) the weld was realized by 625 alloy filler (E-NiCrMo-3) with previous buttering on both pipe and valve side

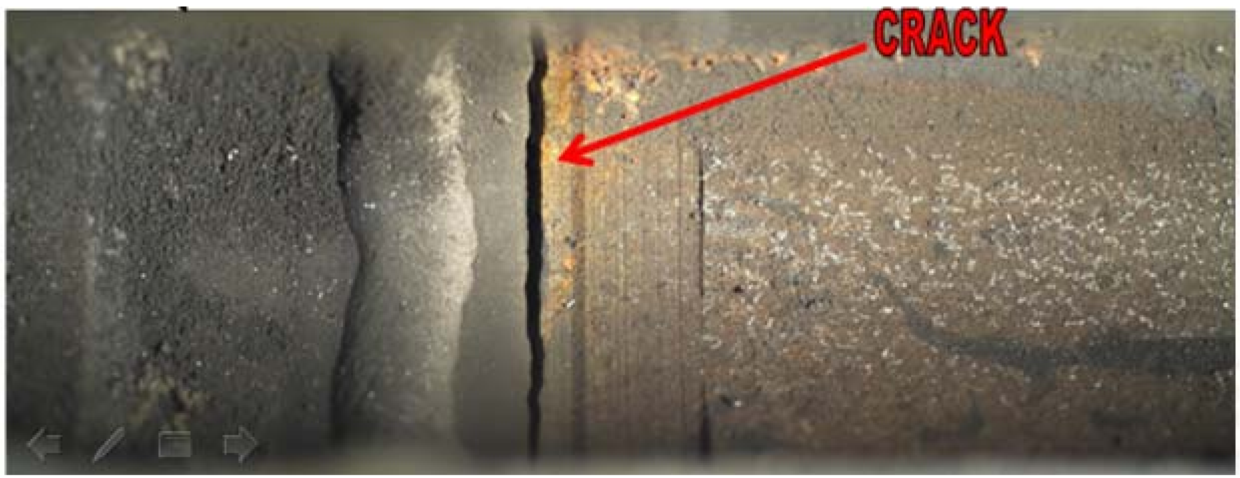


- HV10 hardness on the joint showed values in accordance with sour service requirements.

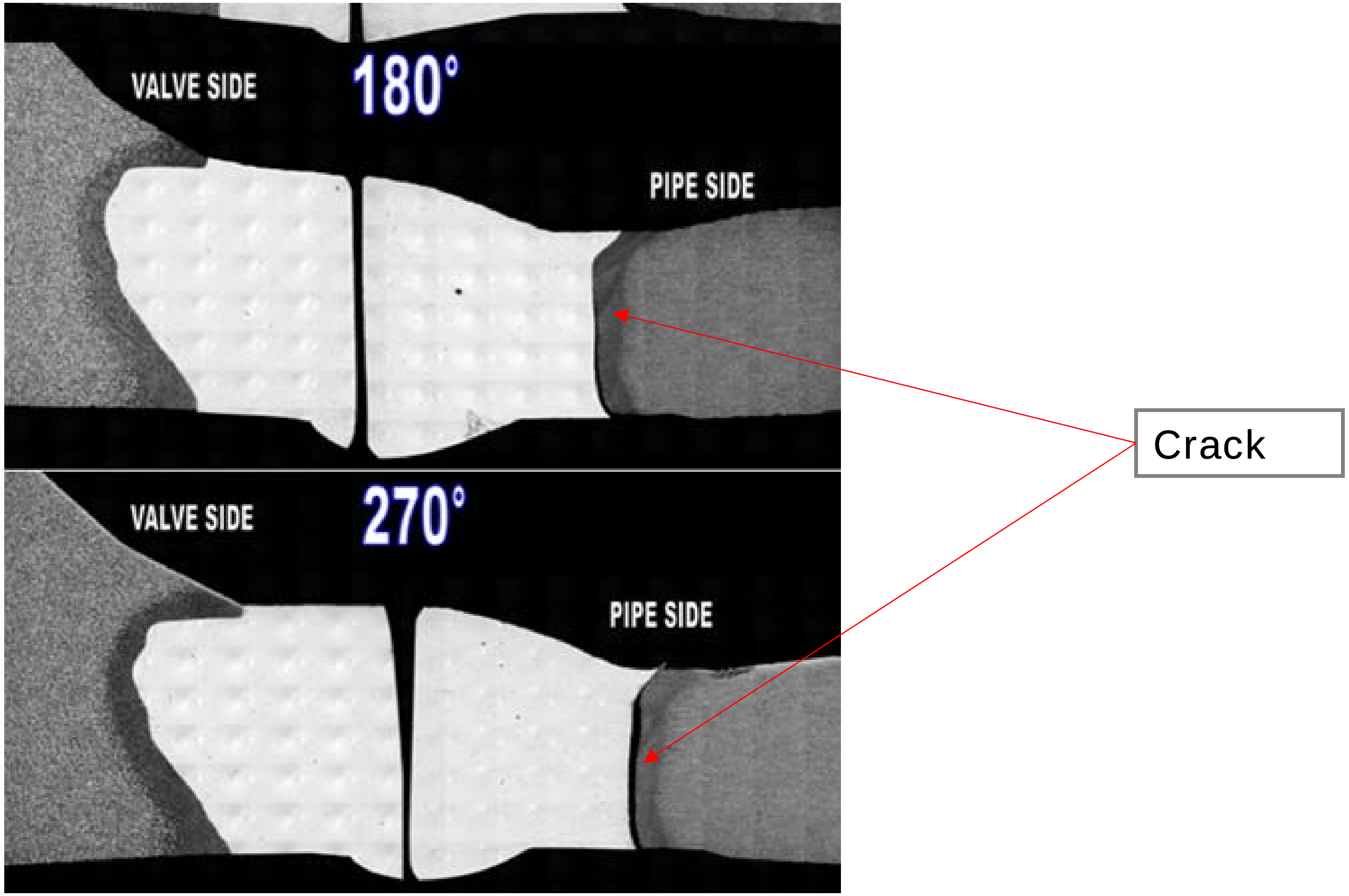
LINE NUMBER	LINE POSITION	VALVE SIDE						WELD METAL			PUP-PIECE SIDE					
		PM			HAZ						HAZ			PM		
LINE #1	CAP	137	146	151	190	200	191	224	214	215	212	216	216	133	135	131
LINE #2	CENTRE	140	141	150	194	183	177	227	218	210	197	221	225	133	130	125
LINE #3	ROOT	151	149	156	218	198	200	235	238	219	220	225	221	133	134	132

- But...
- ...after 60 days in operation the valve failed at dissimilar weld -> circumferential crack.
- NOTE: analysis of deposits on internal surface showed indications of water condensate and sour environment

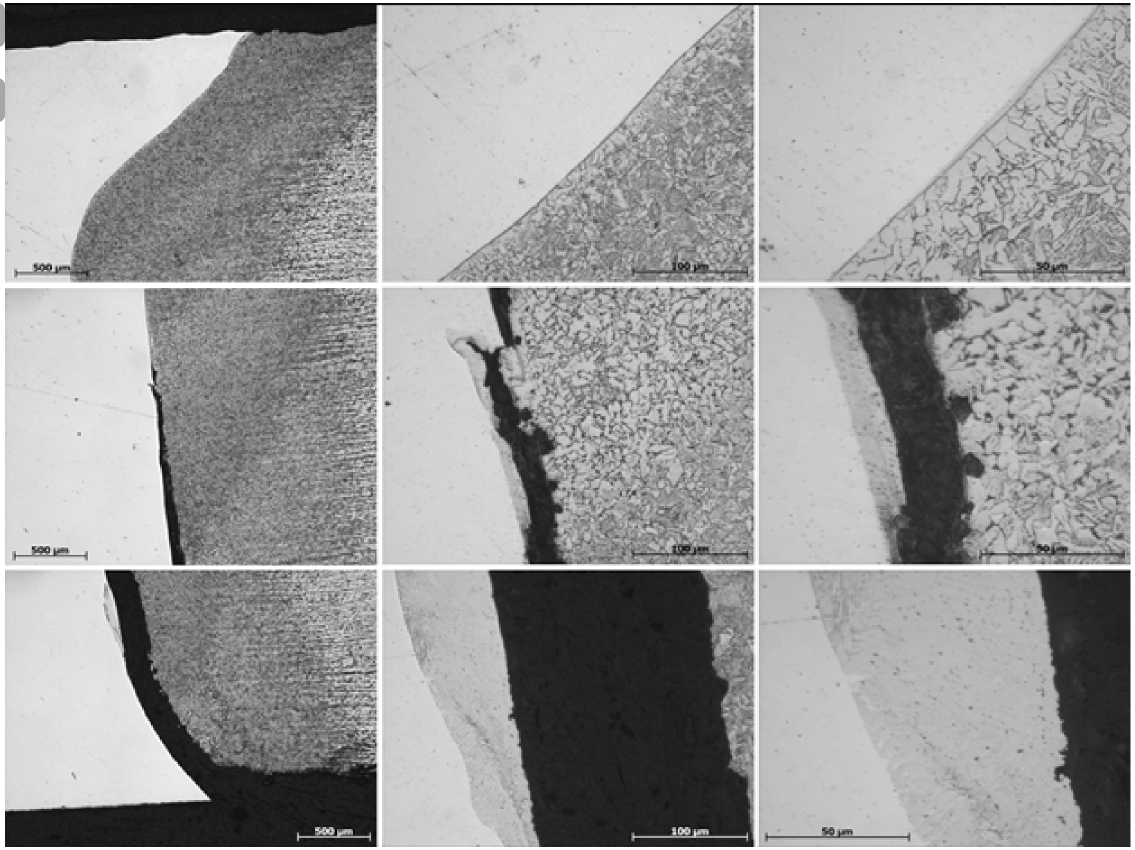


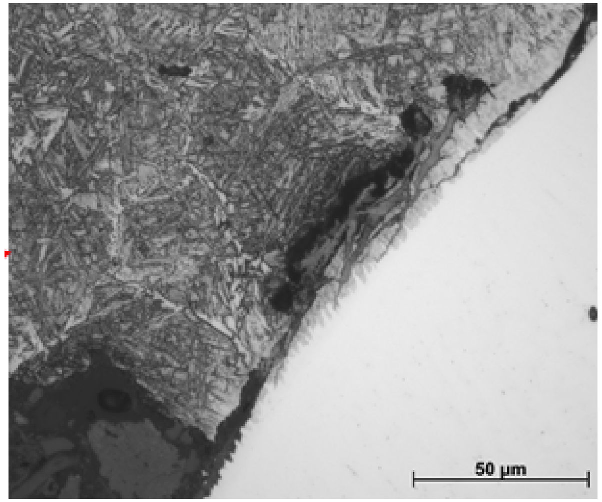


- Crack path along the fusion line.
- Macroscopically the crack does not seem a typical SCC phenomena



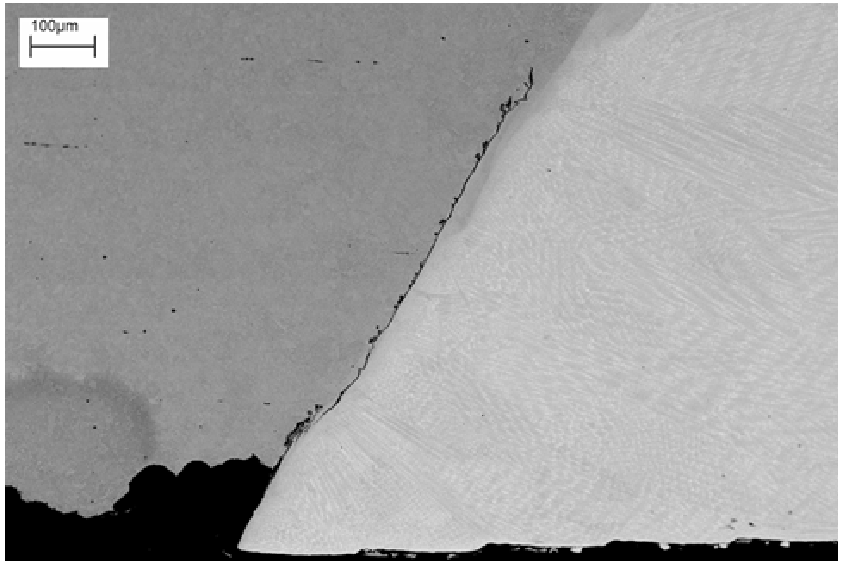
- Microscopically the scenario changes totally.
- Crack path along the fusion line, with corrosion products inside
- Partially Mixed Zone (PMZ) of dissimilar welding
- Chemical composition gradients induce the formation of martensitic structure.

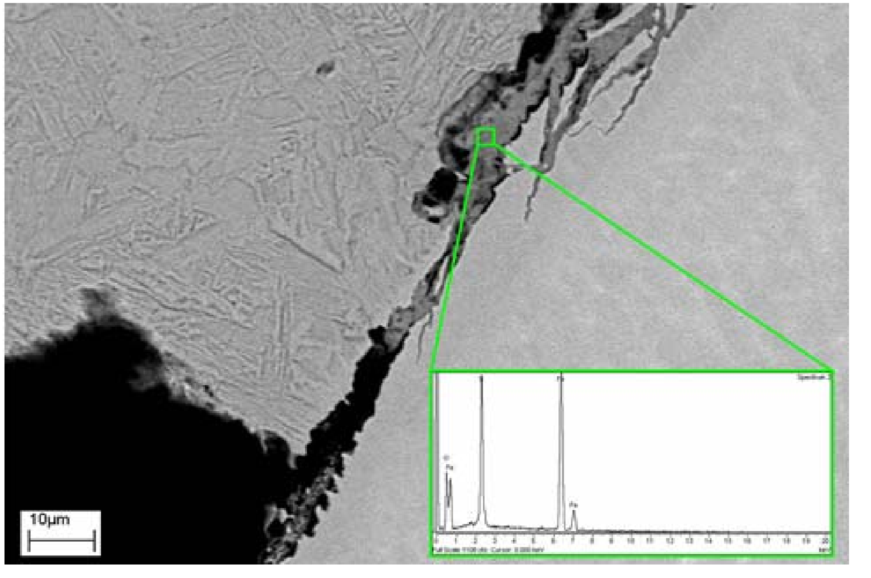




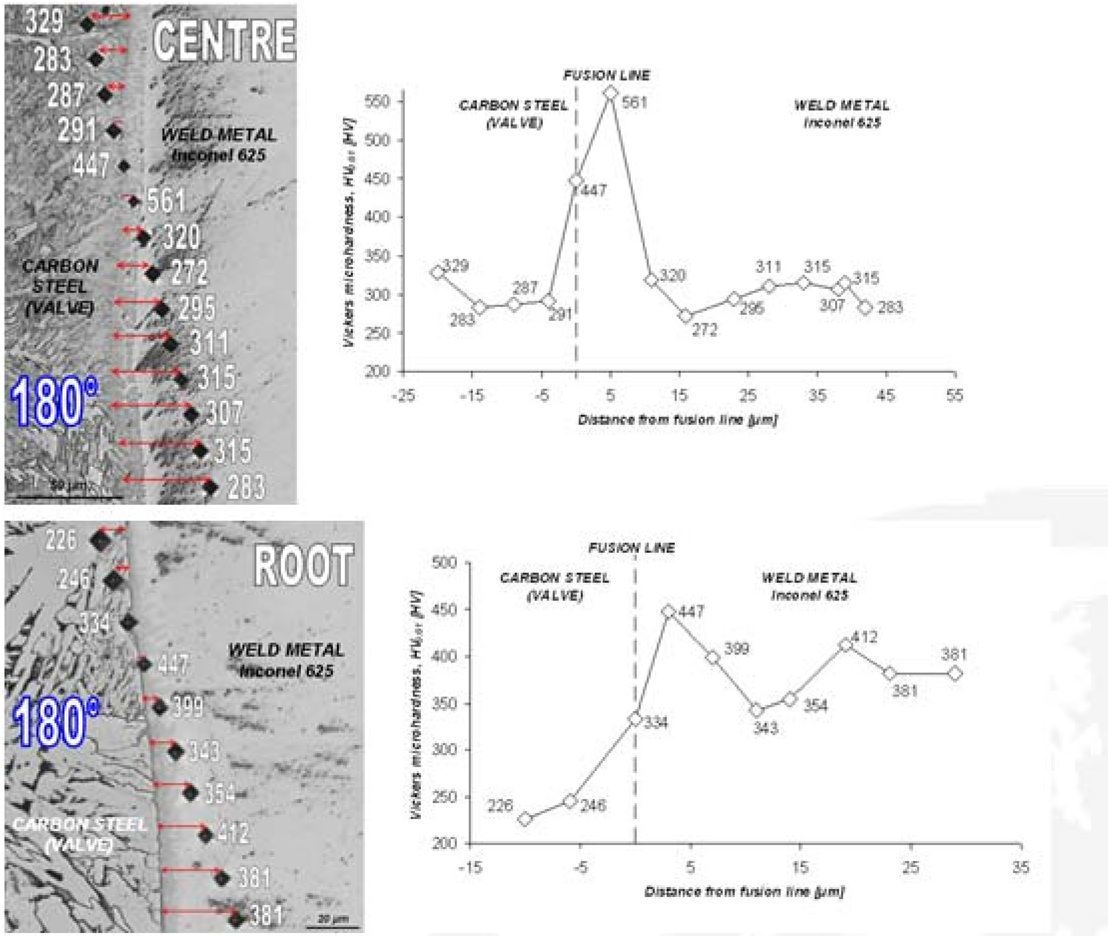
Small crack along FL at dissimilar welding in the joint on the other side of the valve (apparently sound)

Locally branched with corrosion product inside.

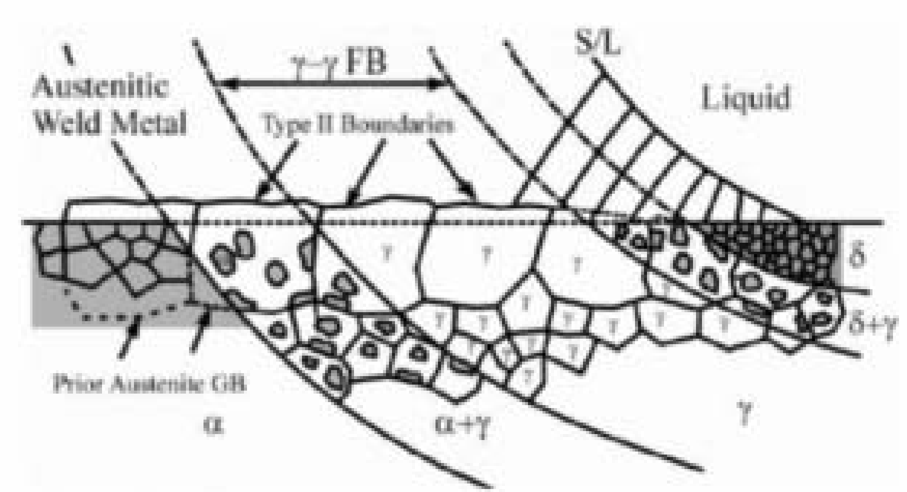


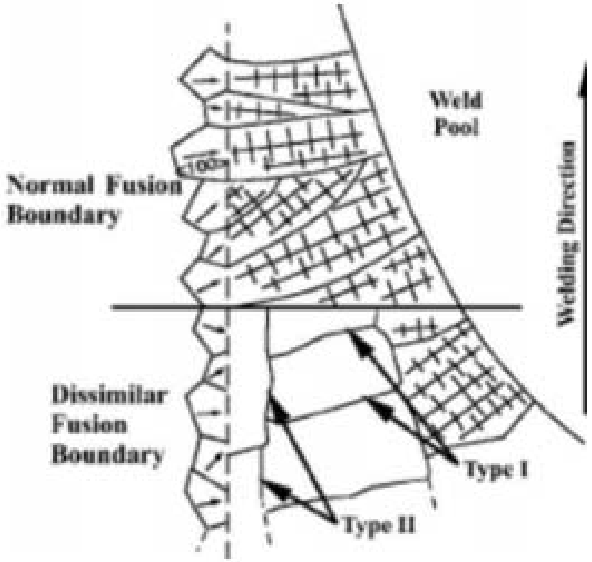


- Microhardness profile across fusion line in cracked dissimilar welding.
- Hardness peaks with very high values
- MATERIAL SUSCEPTIBLE TO SSC IN WET SOUR SERVICE

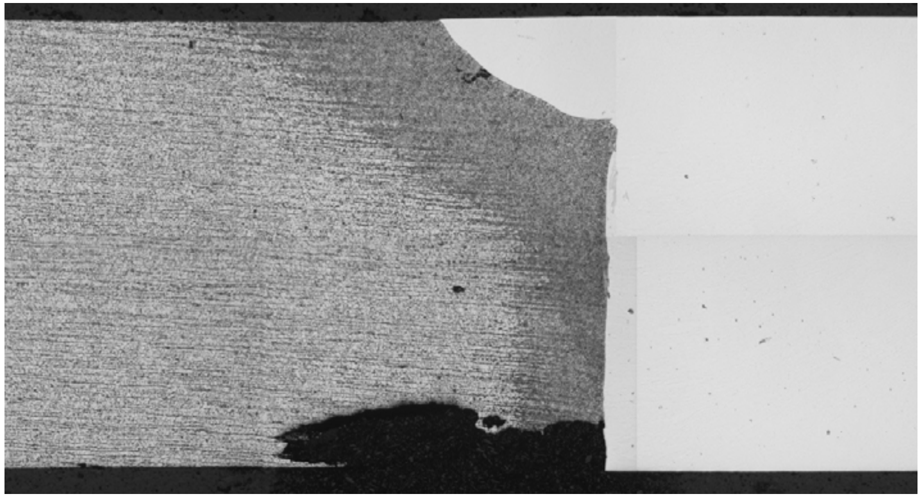


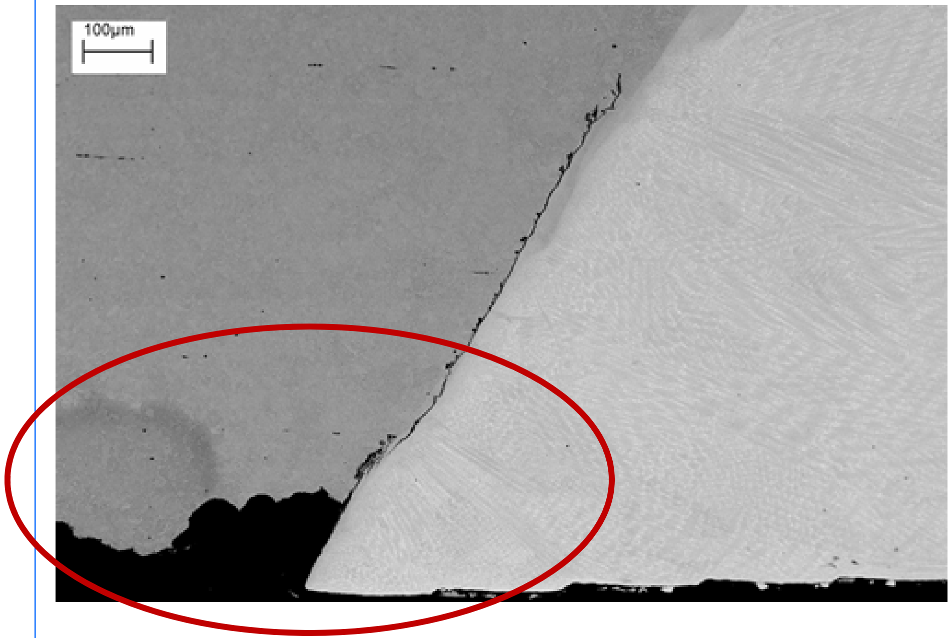
- Dissimilar welding between CS and nickel alloys induces the formation of Type II grain boundaries parallel to fusion line with high energy -> weak point for crack nucleation
- High hardness induced in PMZ by chemical gradients increases the susceptibility to Hydrogen cracking.
- SSC is cause by Hydrogen -> hardness critical factor in Hydrogen induced fracture
- Normal hardness measurements carried out during weld qualification cannot put in evidence this narrow critical zone.



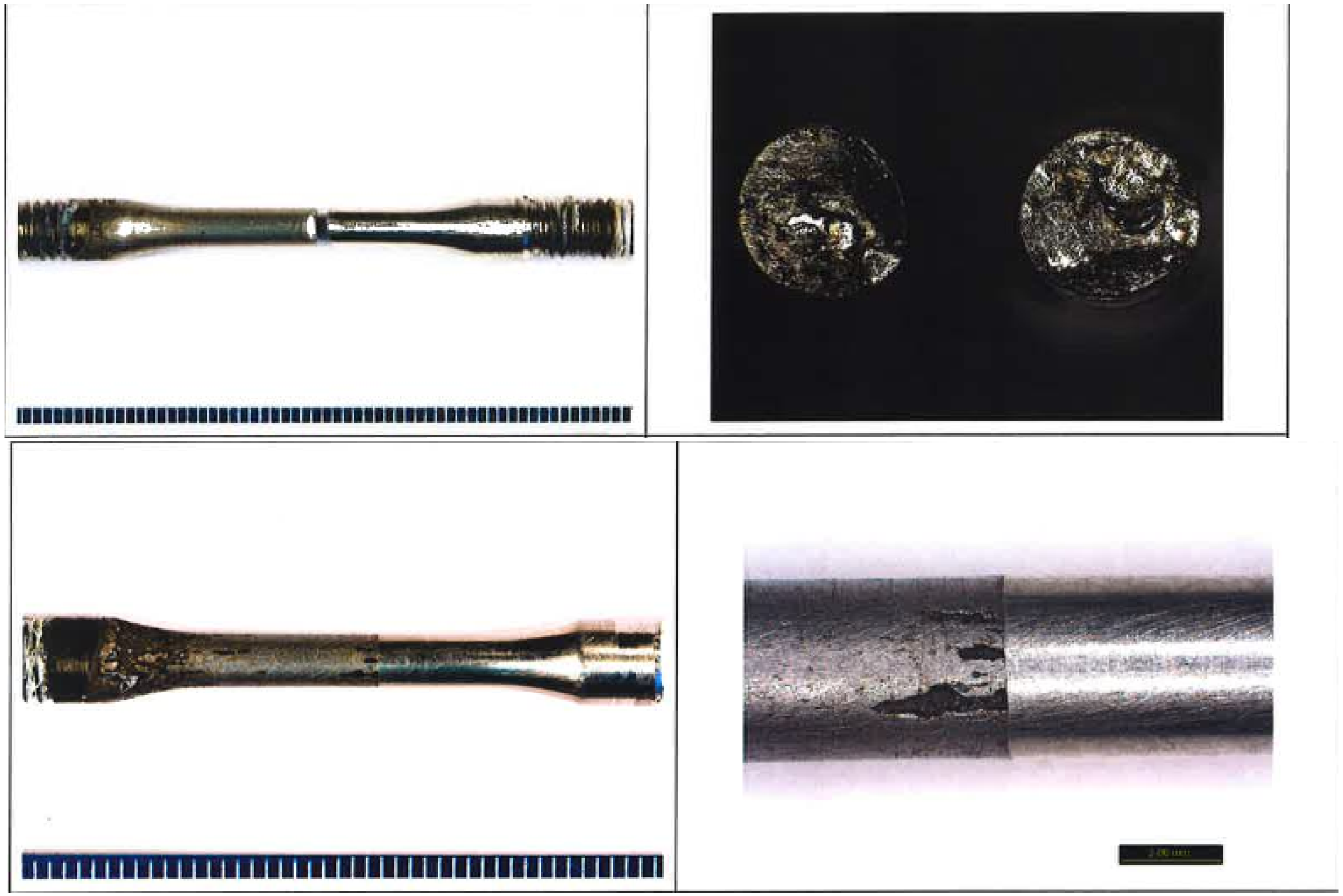


- In presence of corrosive electrolyte (chlorides, low pH), galvanic corrosion at fusion line can increase the hydrogen charging effect of sour environments





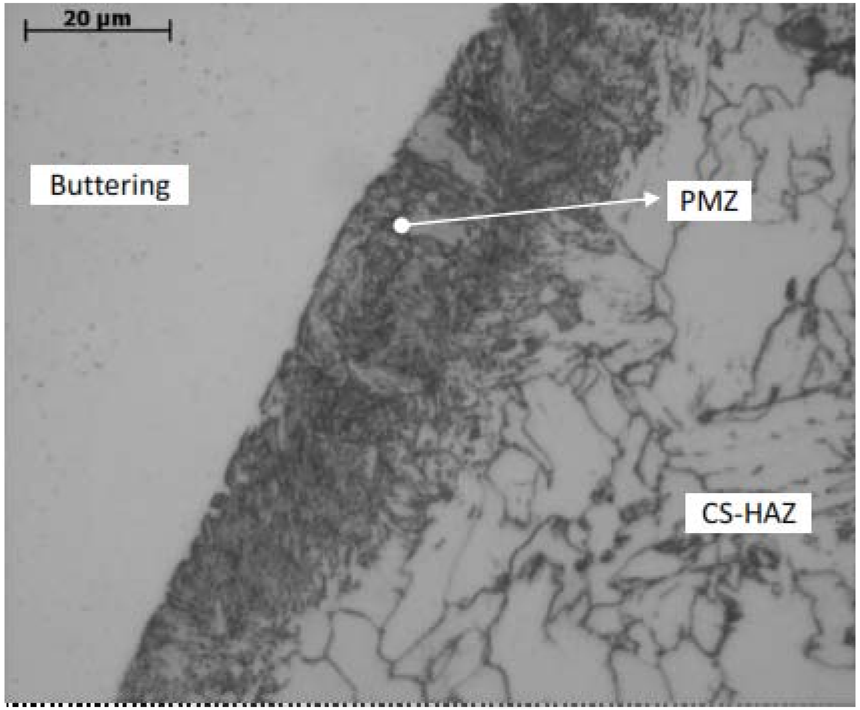
- NACE TM 0177 SSC test con sample taken from sound weld
- 2 of 3 specimens fractured after 720h
- Not fractured specimen with small cracks and signs of corrosion on CS side
- Fracture very similar the one occurred in service!



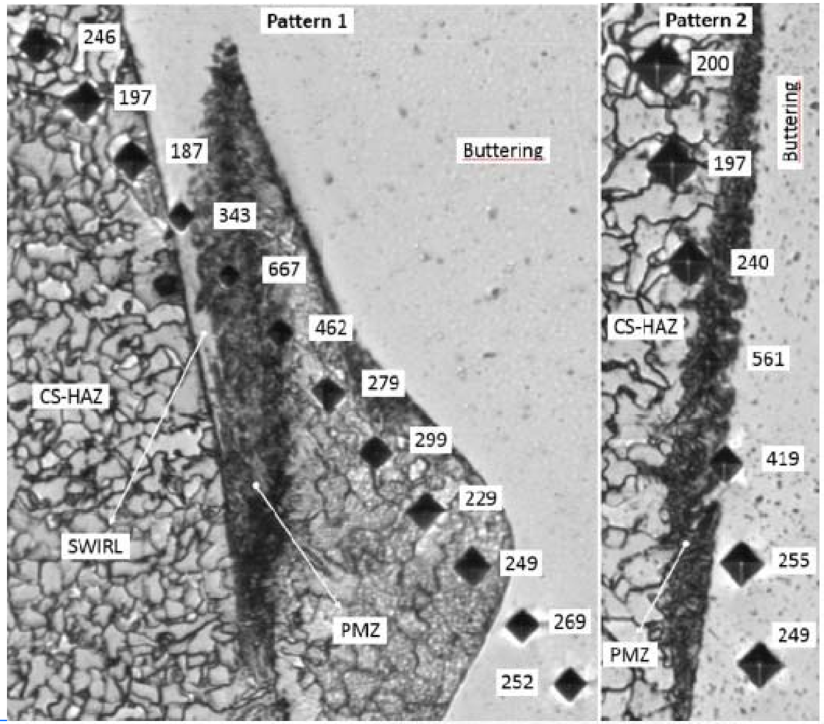
CAN PWHT MITIGATE THE CRACKING SUSCEPTIBILITY OF DISSIMILAR WELD IN SOUR SERVICE?

- PWHT induces carbon migration to PMZ with high hardness values.
- PWHT cannot relive hardness peaks in dissimilar weld CRA/CS.
- Welded joint still remains susceptible to SSC in environments that can sustain the damage mechanism.

610 °C 60 min.



610 °C 60 min.



Appendix 10

Opportunity Crude Processing and Optimized Blend Management with Crude Corrosivity Prediction System

(S. Kus)

Dr. Slawomir Kus
EFC Meeting Dalmine

Opportunity crude processing and optimized blend management with crude corrosivity prediction system

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Outline

1. Opportunity crudes processing – benefits and threats
2. Crude blending approach and corrosion
3. Crude corrosivity prediction – model development and outcomes
4. Blending and crude corrosivity prediction – static approach
5. Real time blending / prediction / monitoring
6. Summary and Q&A

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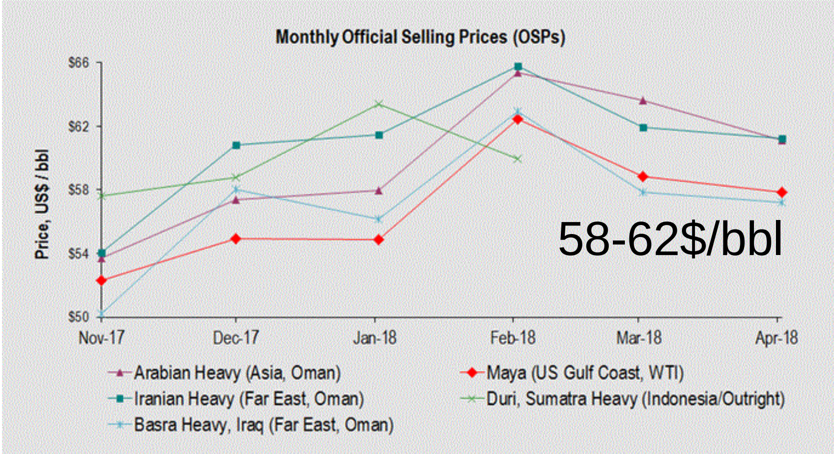
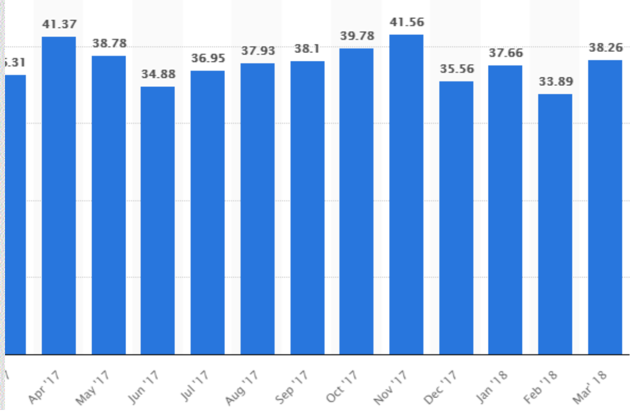
Opportunity crudes – benefits to refinery

- Reference crude oils prices (WTI, Brent etc.) increasing since mid of 2016
- Discount for e.g. Heavy Canadian Crude (WCS) typically varies from 13$ to 25$/bbl
- 13M$ of theoretical additional income for refinery – when processed a single, mid-size tanker of heavy crude (c.a. 1M bbl or 160,000m³)



WCS 32-38$/bbl



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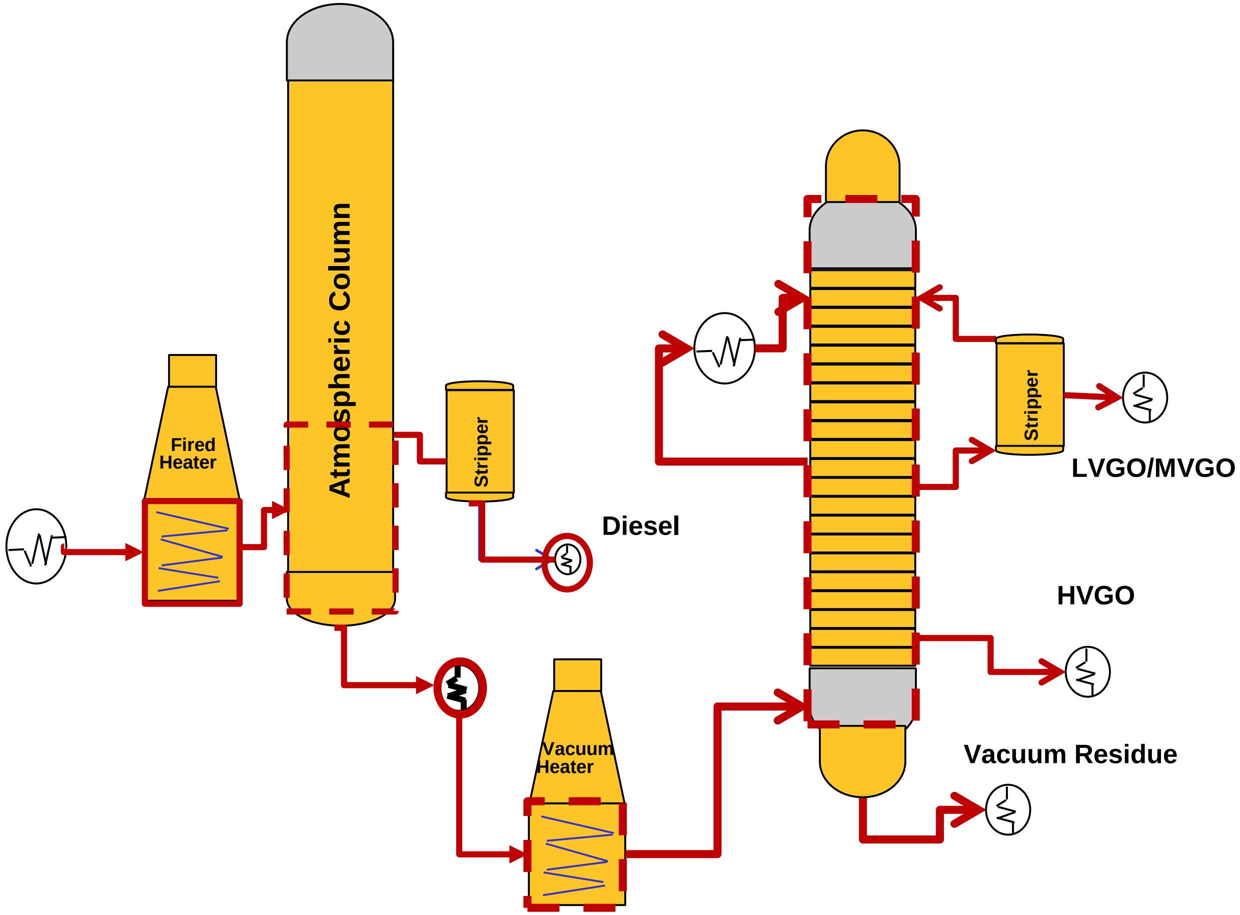
Opportunity crudes – danger to refinery

- Opportunity crudes have different corrosion characteristics than traditional light and sweet feedstock
- High conc. of naphthenic acids and organic sulphur compounds
- Dominant damage mechanisms:
  - Sulfidic corrosion
  - Naphthenic acids corrosion
- **Affected equipment:**
  - Crude heater and transfer lines
  - Bottom of CDU (>220°C) and respective side cut lines
  - Atmospheric residue transfer
  - Major part of vacuum column – especially side cut lines (VGO, MVGO, HVGO etc.)
  - Vacuum residue transfer lines



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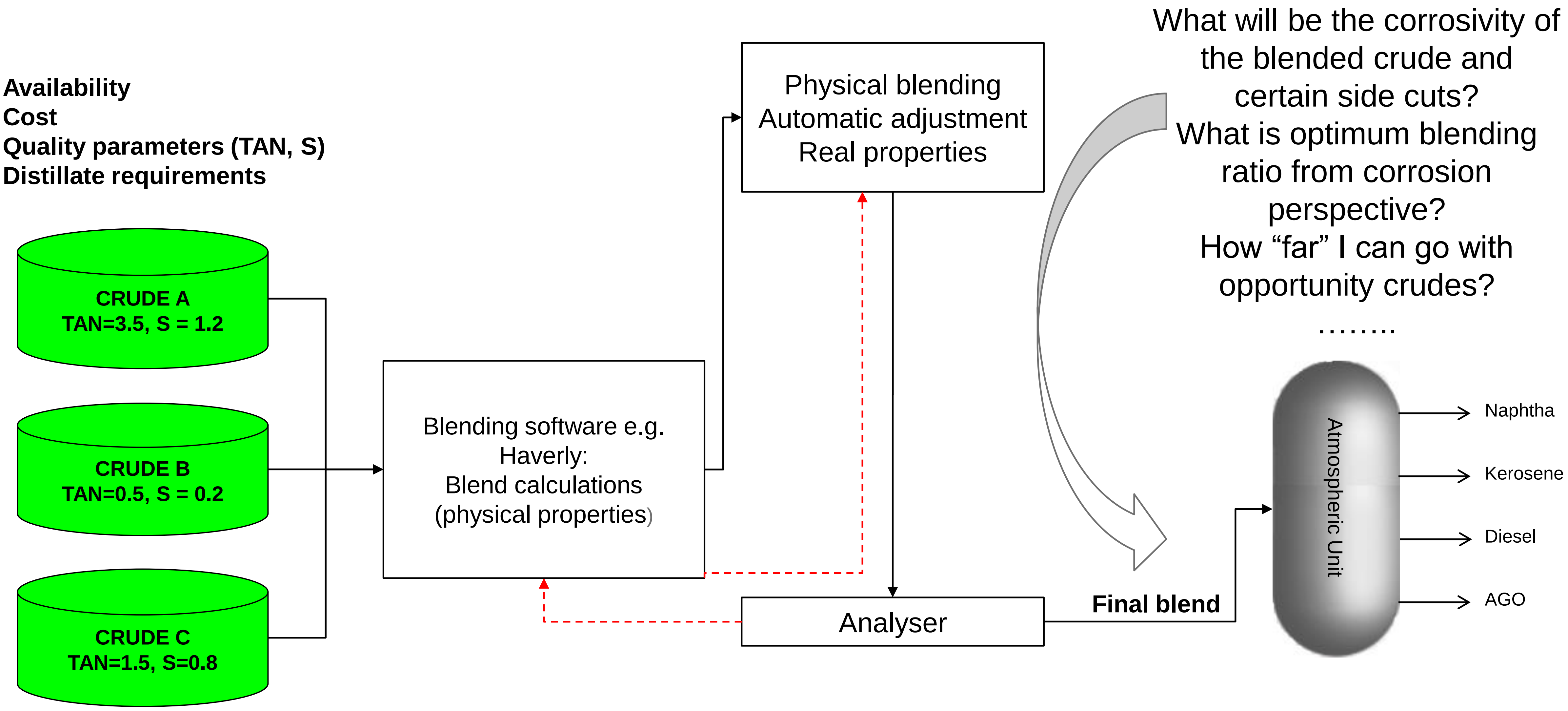
Crude blending approach and corrosion



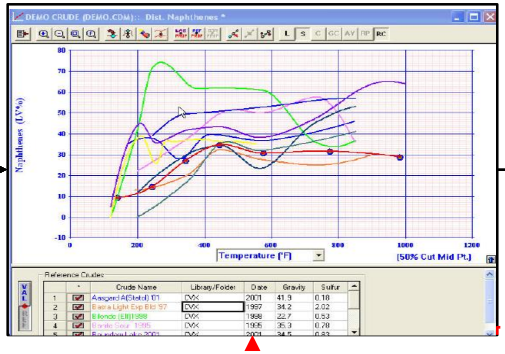
Crude blending approach and corrosion

Availability
Cost
Quality parameters (TAN, S)
Distillate requirements

CRUDE A
TAN=3.5, S = 1.2

CRUDE B
TAN=0.5, S = 0.2

CRUDE C
TAN=1.5, S=0.8

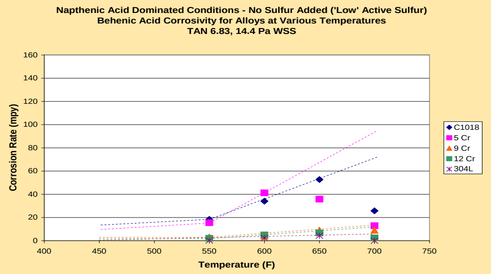


Physical blending
Automatic adjustment
Real properties

Analyser

Final blend

Corrosion prediction



Atmospheric Unit

Naphtha
Kerosene
Diesel
AGO

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Crude Corrosivity Corrosion Prediction model development

Crude Corrosivity JIP Phase 1

- Dec 2006 – June 2010
- 200+ high temp autoclave tests
- 8 steels and alloys tested (CS, 5Cr, 9Cr, 12Cr, 304, 316, 317, 904)
- Experiments at T ranged from 230 to 370°C)
- Synthetic Crude Oils with TAN values of 1, 3, 5.5
- Sulfur simulated using H2S additions (0.5% ÷ 5% H_2S/N_2)
- WSS values ranging from 0.1 to 135 Pa
- Experimental Duration (48 or 168h)
- Benchmarking with sponsor-supplied vacuum gas oils selected with various characteristics (TAN/active S)

Crude Corrosivity JIP Phase 2

- Jan 2013 - Dec 2017
- Addressed data gaps in the Phase I program
- Generated in-depth understanding of the role of active sulphur species, and corrosion in low acid content conditions
- High WSS tests (20 tests, WSS up to 1000Pa) using special HOFL (hot oil flow loop)
- 210 high temp autoclave tests
- Upgrade of Phase I Prediction Model
- Benchmarking with sponsor-supplied VGO & AGO with various TAN/active S

Crude Corrosivity JIP Phase 3

- Q2-Q3 2018 (JIP Phase III planned commencing)
- Further expand capabilities in corrosion prediction including:
  - high velocity and multiphase flow across a range of wall shear stresses,
  - conditions with high temp,
  - impact of broader range of naphthenic acid species,
  - create fundamental models for expressing active sulphur and naphthenic acid corrosivity based on principals for molecular and empirical modelling.
- JIP is still open for participants

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Corrosion prediction of blended crude – static approach

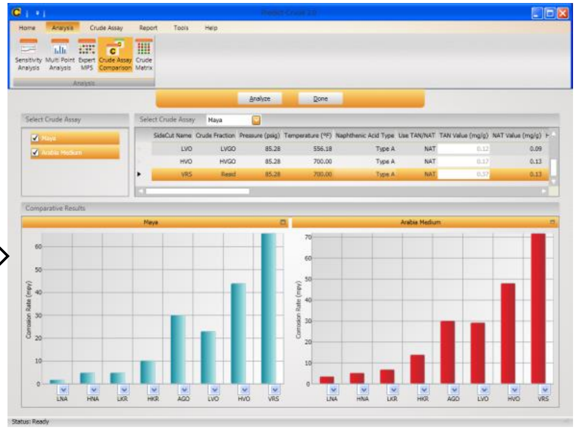
Crude A & Crude B
(blended e.g. 90/10 as per existing blending software to meet production target)

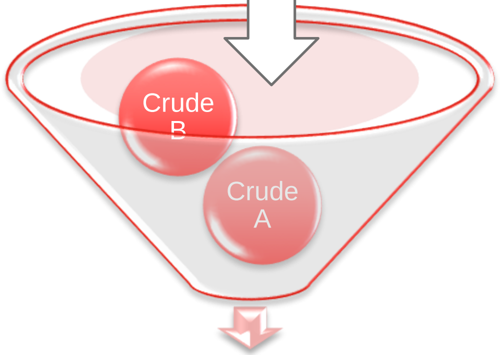
CRUDE A
TAN=3.5, S = 1.2

CRUDE B
TAN=0.5, S = 0.2

Build a database for individual crude slates / blends/ side cuts

Crude A & Crude B Analysis
Properties database (Sact/TAN/NAN/ etc.) + Fractions





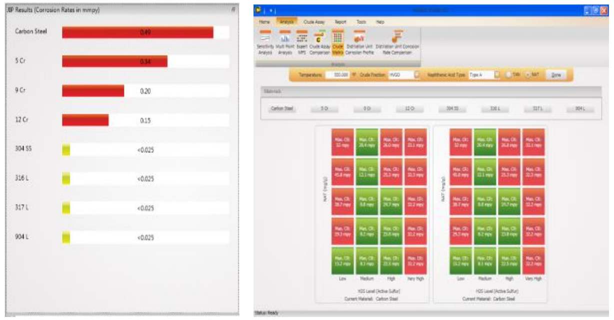
Blended slate for process

Prediction Engine
Predict® Crude

HIGH CR / Modify Blend

Predicted CR

OK for processing

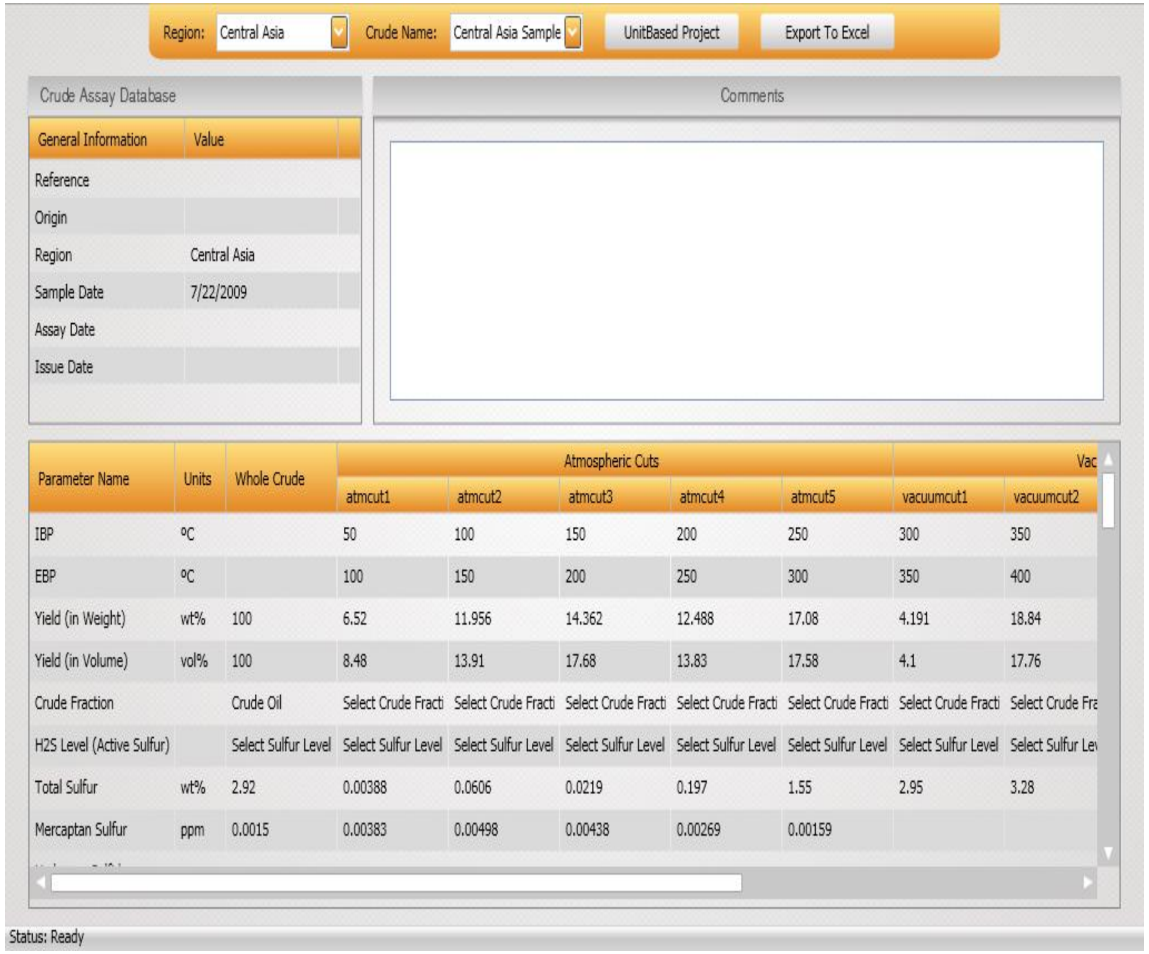


Corrosion map / Excel

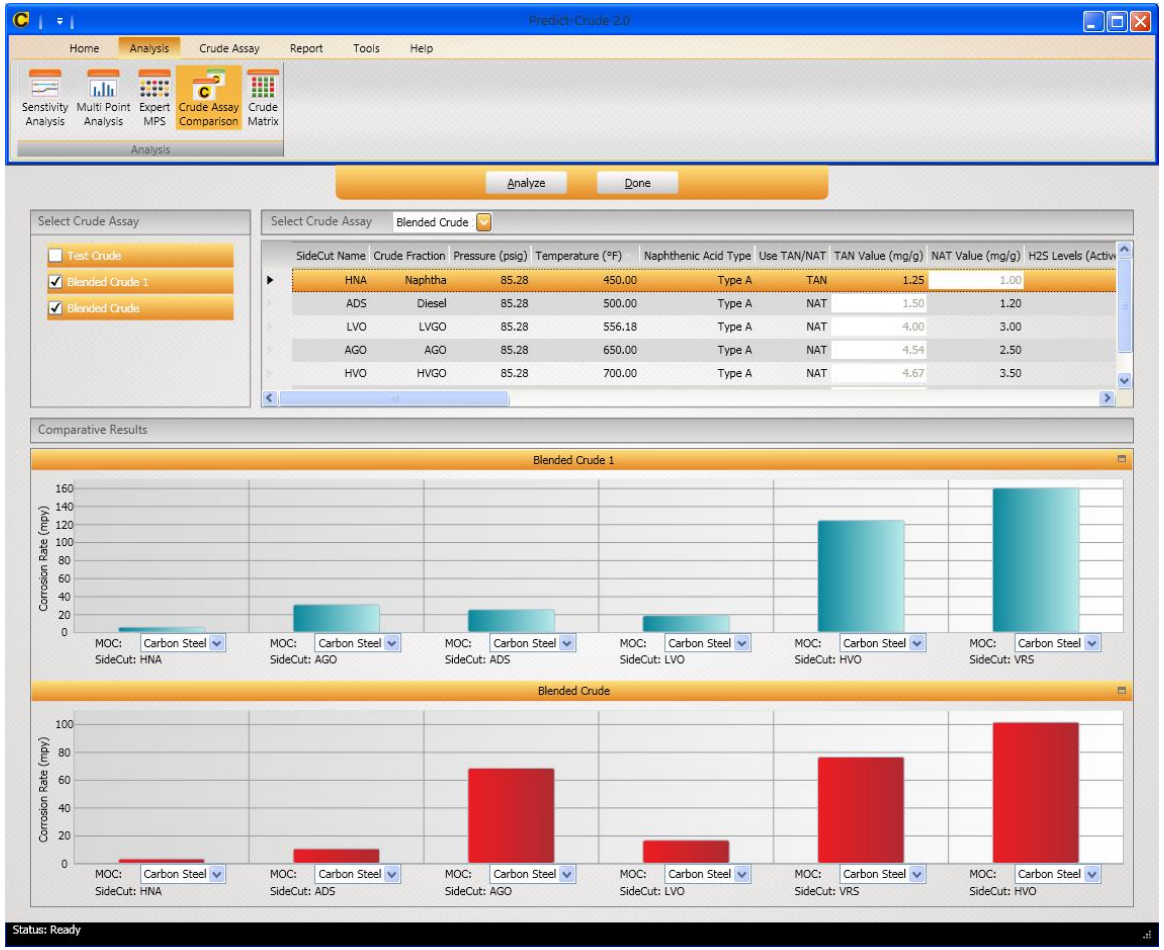
For field case description see NACE paper 2018-11381

Crude Assay Corrosivity Database

Database



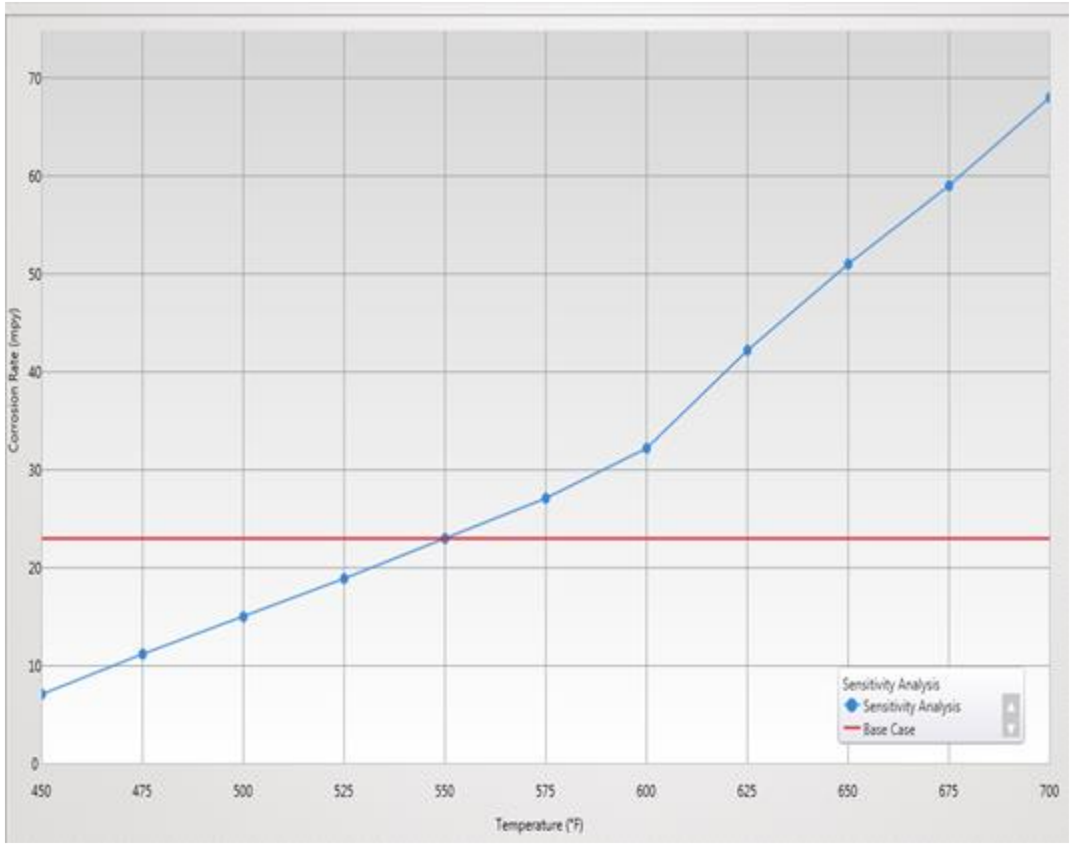
Crude/side cuts corrosivity comparison



Crude corrosivity mapping

Side-cut corrosivity mapping

Sensitivity Analysis



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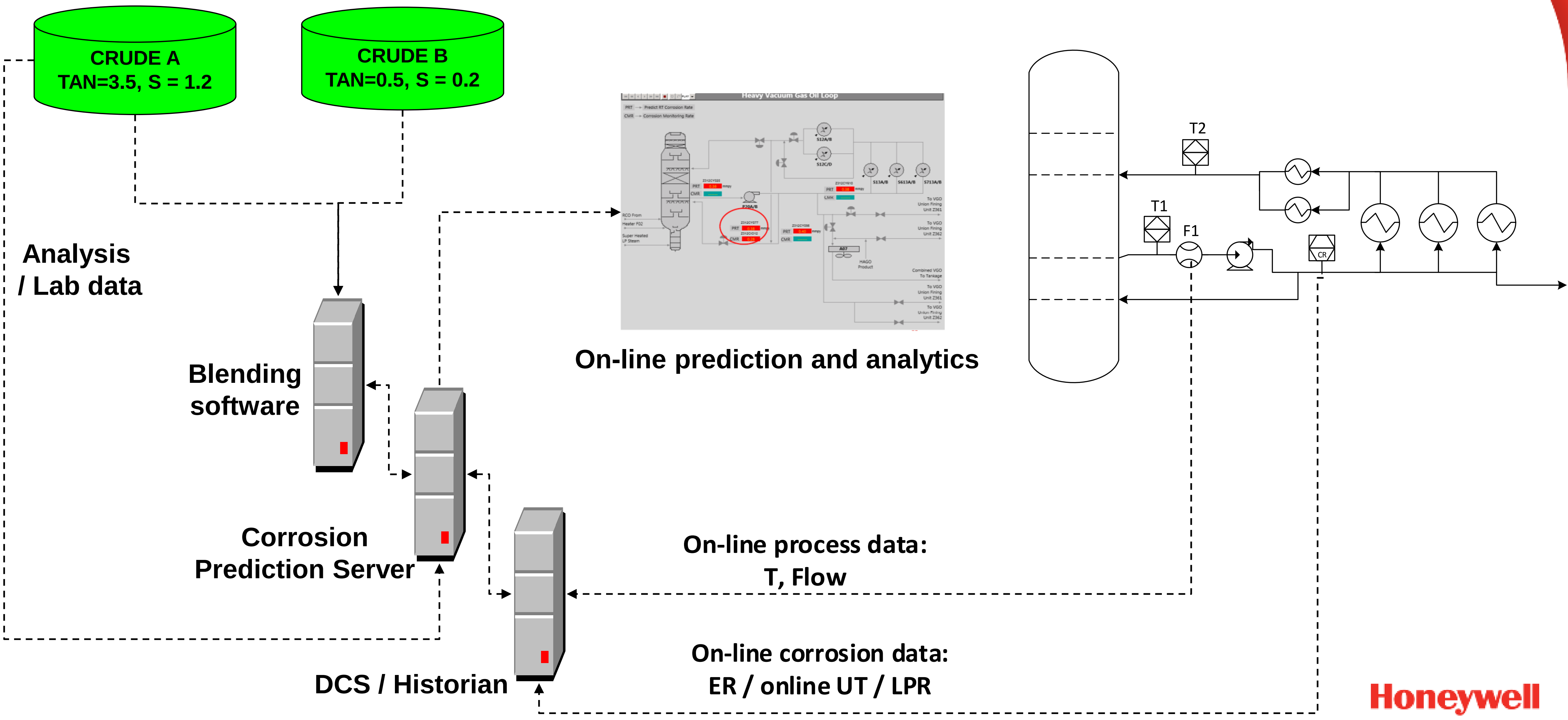
Corrosion prediction of blended crude – real time approach



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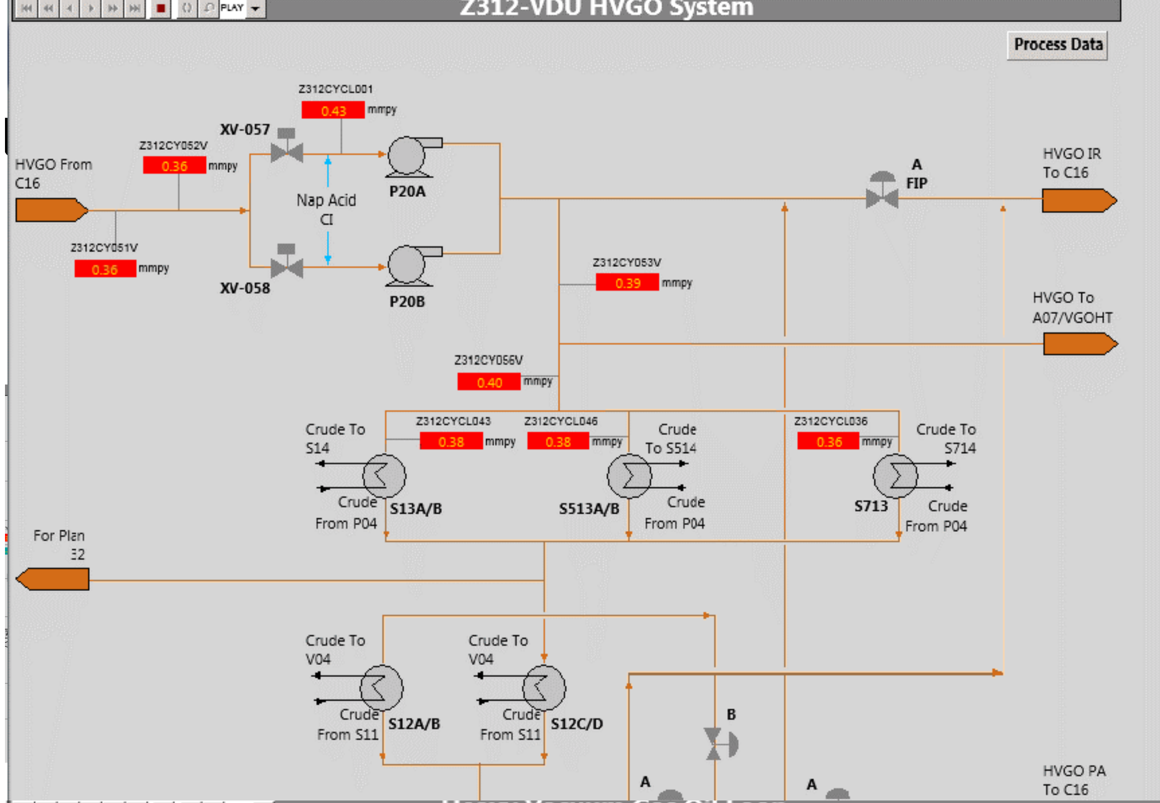
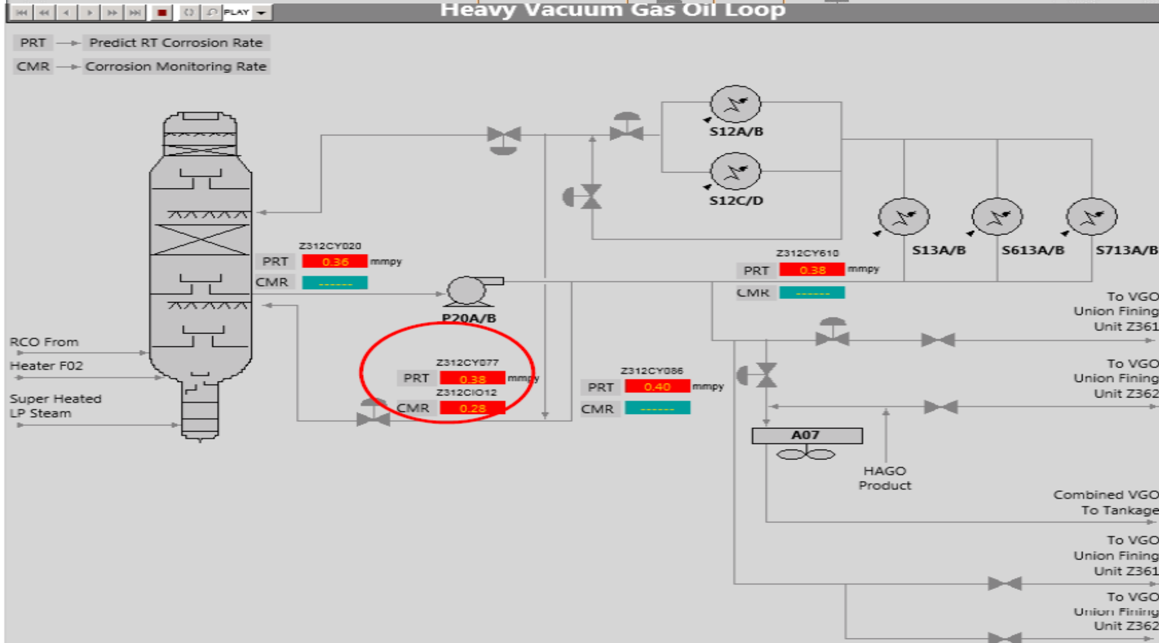
KPI	30 Days(Corrosion Rate, mmpy)	Accp.Limit(mmpy)	Inst. CR(mmpy)	30 Days Avg. CR(mmpy)	Corrosion Sensor Reading(mmpy)
FV077 Valve-Down. Elbow		0.25	0.38	0.38	0.28
FV086A Valve - Down Elbow		0.25	0.41	0.40	NA
HVGO pumps (P20A/B) -HVGO...		0.25	0.38	0.38	NA
HVGO pumps (P20A/B) HVGO ...		0.25	0.38	0.37	NA
HVGO pumps (P20A/B) to HV...		0.25	0.36	0.36	NA
HVGO pumps (P20A/B) to fl...		0.25	0.40	0.40	NA
Inlet of HVGO pump (P20A)...		0.25	0.43	0.43	NA
Old PV610 Loop-Elbow u/p		0.25	0.38	0.38	NA
Outlet of HVGO pumps (P20...		0.25	0.39	0.39	NA
P20A Suction piping		0.25	0.36	0.36	NA
VC (C16) to HVGO pumps (P...		0.25	0.36	0.36	NA
VC (C16) to HVGO pumps (P...		0.25	0.36	0.36	NA





Summary

- Refiners now have ability to make informed decisions about crude blends to process and blends to avoid
- It is now possible to validate current metallurgy (CDU/VDU) versus different blends and identify crude fractions to avoid
- On-line, real time integration of blending data and corrosion prediction allows for faster, quantitative evaluation of NAP Acids corrosion and Sulphidation phenomenon
- New data on effects of sulfur in crude and sulphidation, provides a paradigm shift, allowing use of carbon steel under certain combinations of medium sulfur and high TAN conditions
- New insights correlating role of NAP acids in determination of corrosion rate in crude fraction will enable handling of high TAN crudes
- Increase operating margins and work with opportunity crudes with consequent improved profitability

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Appendix 11

Corrosion under pipe supporting

(S. Tarentino, G. de Landtsheer)

Borealis : Static Equipment – Inspection & Materials technology
Sitech : Integrity Management Department

Corrosion Under Pipe Supports (CUPS)

⇨ Risk Assesment, Detection,& Repair

Corrosion Under Pipe Support strategy needs to be seen as part of the CUx inspection strategy
(CUx = CUI + CUPS + CUL+CUF+…)

Sebastian Tarantino,
Senior Integrity Engineer
Sitech Services (NL)

Gino De Landtsheer,
Senior Group Expert Piping & Valves
Borealis

Project & Technical Support (PTS)
Division: I-PMO & Engineering

sitech services

BOREALIS

Part 1: Introduction

Introduction

→ Why thinking about CUPS strategies?

- Recent incident in Geleen (NL), causing a fire, was a trigger to investigate inspection strategies
- CUPS was not yet recognized as a possible safety factor

→ Scope:

- Definition of guidelines for inspections, maintenances strategies, lifting procedures for pipes
- Definition of parameters to perform a dedicated risk assessment

→ Stakeholders:

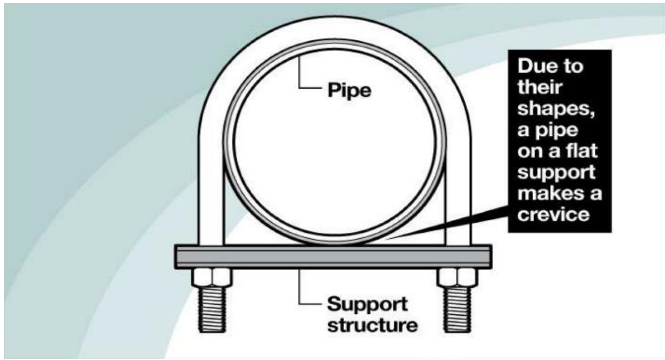
- Sitech Services, Borealis, DSM, Chemelot Chemical Site (NL)

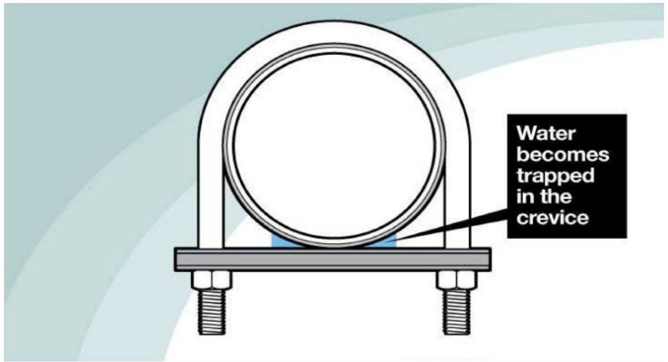
→ Necessary actions:

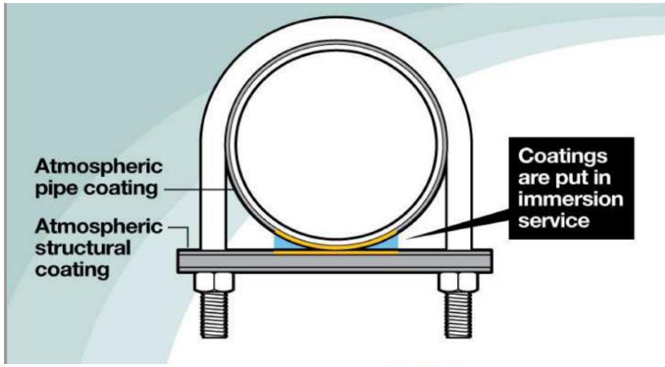
- Check & evaluation of possible existing CUPS strategies in the industry
- Preparation of specifications and procedures, fit for purpose in our operational plants
- Definition of risk rating tool, to allow a decision making process, when to take the necessary actions

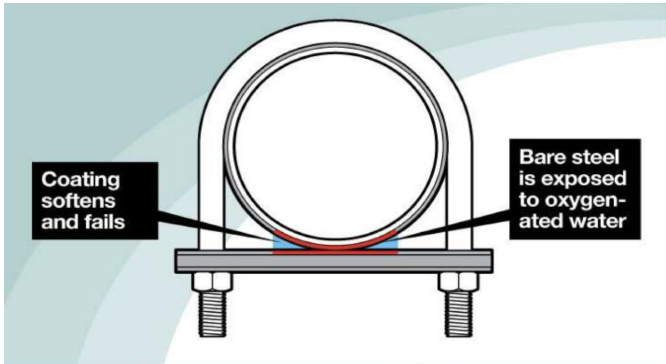
Part 2: Results of ongoing actions

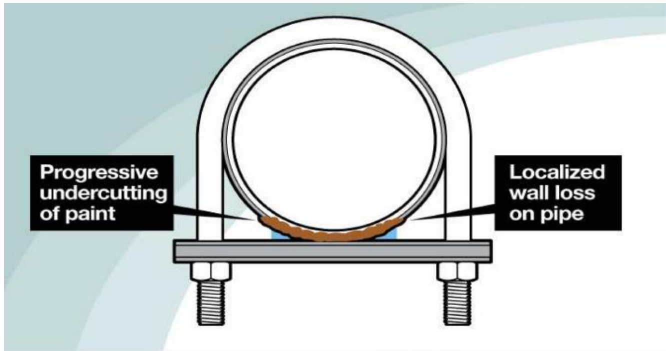
CUPS – Damage & Degradation Mechanism











CUPS – Strategy Document

→ Introduction:

- Cause of external corrosion failures on above-ground piping in aging facilities
- This document applies to all carbon steel, low allow steel and stainless steel piping.
- Main risk are that CUPS is:
  - It is not easily visible
  - May be under estimated

→ Target:

- Implementation of a CUPS strategy, that can be independent but preferable integrated in a general CUx strategy.

→ Parameters taken into consideration / probability assessment:

$$\begin{matrix} Probability \\ factor \end{matrix} = P_{AC} \times P_{PF} \times P_{PM} \times P_{WT} \times P_{T} \times P_{YSP} \times P_{YSC} \times P_{ST} \times P_{SM} \times P_{Pad.M}$$

Prob. Factor	Description
P_{AC}	Atmospheric condition
P_{PF}	Piping failure
P_{PM}	Piping material
P_{WT}	Piping wall thickness
P_{T}	Process temperature

Prob. Factor	Description
P_{YSP}	Years in service (piping)
P_{YSC}	Years in service (coating)
P_{ST}	Support type
P_{SM}	Support material
$P_{Pad.M}$	Pad material

CUPS – Strategy Document

→ Parameters taken into consideration / probability assessment:

- Draft of probability ranking defined as:

Probability Ranking	Consequence Value
5	> 28
4	12 – 28
3	5 – ≤12
2	2 – ≤5
1	≤ 2

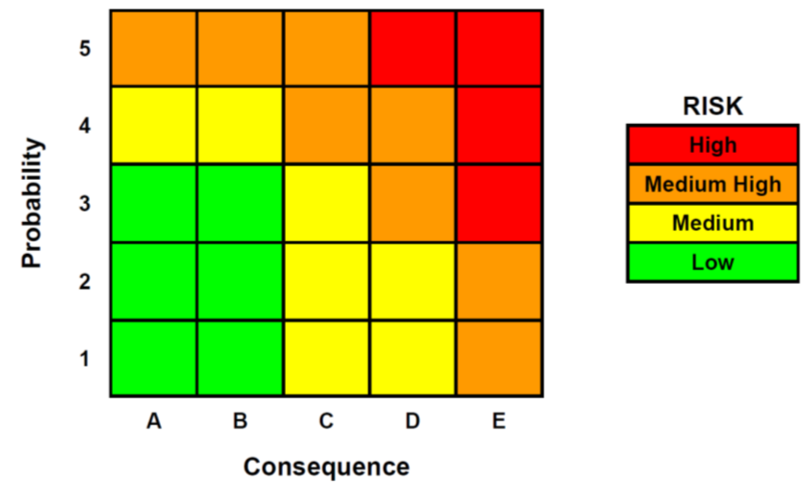
→ First lessons learned:

- Formula too complex – simplified version to be created
- Probability weight of the different parameters was questioned
- Few experience about aging towards CUPS
- CUPS should part of the overall CUx Consequence Assessment exercise, taking care about:
    - Safety and health impacts
    - Environmental impacts
    - Economic impacts

CUPS – Strategy Document

→ Replacement assesment:

- In order to evaluate which piping shall be replaced, a procedure linked to the history of the piping and the risk value of the piping supports, for each line, is developed :
  - 3 or more incidents in the same line, related or not to piping supports, or
  - 30% or more of the piping support with a risk value equal to “High”, or
  - 50% or more of the piping support with a risk value equal to “Medium High”
- Remaining wall thickness < 50% of the nominal thickness = Replacement!



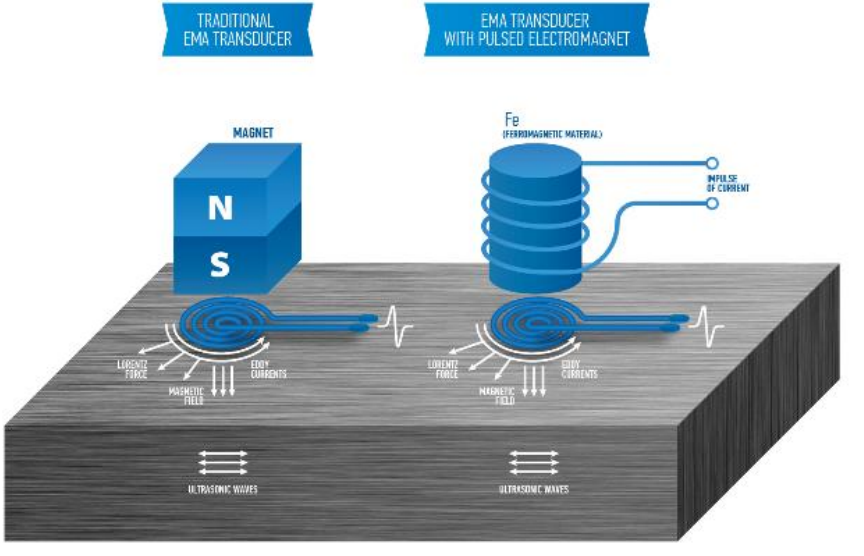
Note: (evaluation parameters still under discussion)

CUPS – Strategy Document

→ Non Destructive Examinations (NDE):

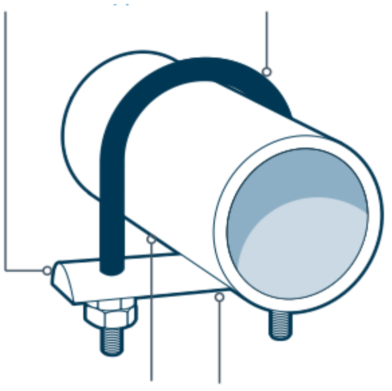
- EMAT techniques / comparison:
  - Verkade technique ⇨ good results ≤ 60°C (due to improves sensor design)
  - Normal EMAT techniques are possible in a broader temperature range, but not as accurate

- Evaluation of possible techniques:
  - Visual
  - EMAT technology (Electro Magnetic Acoustic Transducers)
  - RT (not easy!)



CUPS – Strategy Document

→ Prevention of CUPS:



- Use of pipe shoe shall be mandatory in new design and evaluated in retrofits.
- The crevices at the pipe surface and their ability to trap water must be eliminated.
- As a secondary concern, metal-to-metal contact should be eliminated if possible.
- The solution should allow easy maintenance and inspection of the pipe at the support point.
- The system must provide complete support to the piping system.
- It must be applicable to new construction and retrofits

Pipe Lifting Procedure

→ Introduction:

- Due to lifting, forces/stresses in axial and radial direction will arise in the pipeline. Those forces/stresses will increase if;
  - The lifting height increases, or
  - The distance between the supporting columns or the “arched length” (see Annex 1) increases, or
  - The diameter of the pipeline increases.

→ Target:

- Creation of a typical calculation set-up, which acts as guidance to serve the users in the decision process when to lift and how to lift

→ Risk Assessment:

- Risk assessment shall be an integral part of the supply of lifting equipment;

Pipe Lifting Procedure

→ Lifting Tools:

- Cranes
- Fixed Lifting Beams
- Special Tools
  - Pipe Rack Jack
  - Hydraulic Pipe Lifting

Pipe Lifting Procedure

→ **Categorization:**

- On-Stream Lifts:
  - Consequence ranking ≤ 3
  - Process temperature ≤ 60°C
  - Acceptable stress calculations

- Shutdown Lifts:
  - Consequence ranking ≥ 3
  - Process temperature ≥ 60°C
  - Not acceptable stress calculations

For both cases, it is mandatory to perform a risk assessment and a lift plan

Appendix 12

JIP proposal corrosion under insulation on

(J. Sentjens)

Leonardo Caseres, Ph.D.

Senior Research Engineer

Environmental Performance of Materials

CUI JIP – Southwest Research Institute
Research Objective and Goals

- **Determine the performance of coating/insulation systems applicable to CUI using the *framework of the TG516 test method*. This program will enable:**
  - An accurate coating/insulation durability evaluation using two temperature regimes
  - High quality data to support the development/optimization of existing/new coatings and insulations
  - Make/revise recommendations for coating/insulation selection based on durability, define acceptance criteria and safe integrity operating window

NACE TG 516

Corrosion under Insulation JIP

Test Company	Single or multi Specimen testing CUI test	Reproducibility Demonstrated (Externally)*	Cyclic temperature (Range °C)	Immersion conditions or Saturated	Pipe Orientation	Insulation
Sherwin Williams	S	N	Y(Amb – 177°C)	S	N/A	Y
Hempel	S	N	Y(70-450°C)	S	V	Y
PPG	M	?[2]	Y(Amb – 250°C)	I	H	N
Belzona	S	N	Y(70 – 150°C)	S	H	Y
International Paint	S	Y[1]	Y(Amb – 600°C)	S	V	Y
Juton	M	N	Y(Amb -500°C)	I	H	N
Statoilhydro	M	N	Y(Amb -140°C)	I	H	Y
Shell	S	N	Y(Amb – 191°C)	S	N/A	Y

Test proposal stage

Corrosion under Insulation JIP

- **Task 1**: Refine CUI-EM test procedure (in parallel with NACE TG516)
- **Task 2**: Selection of coatings and insulation combinations.
- **Task 3**: Testing
  - 70-175°F (20-80°C)
  - 70-400°F (20-200°C)
  - 70-600°F (20-315°C)

- **Task 4**: Develop durability predictions to make “more timely and better informed decisions on the selection of CUI coatings and insulation materials”

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Appendix 13

Experiences of MIC damage occurred under non-operating conditions

(M. Arzuffi)

Microbiological Induced Corrosion

Experiences of MIC damage occurred under non-operating conditions

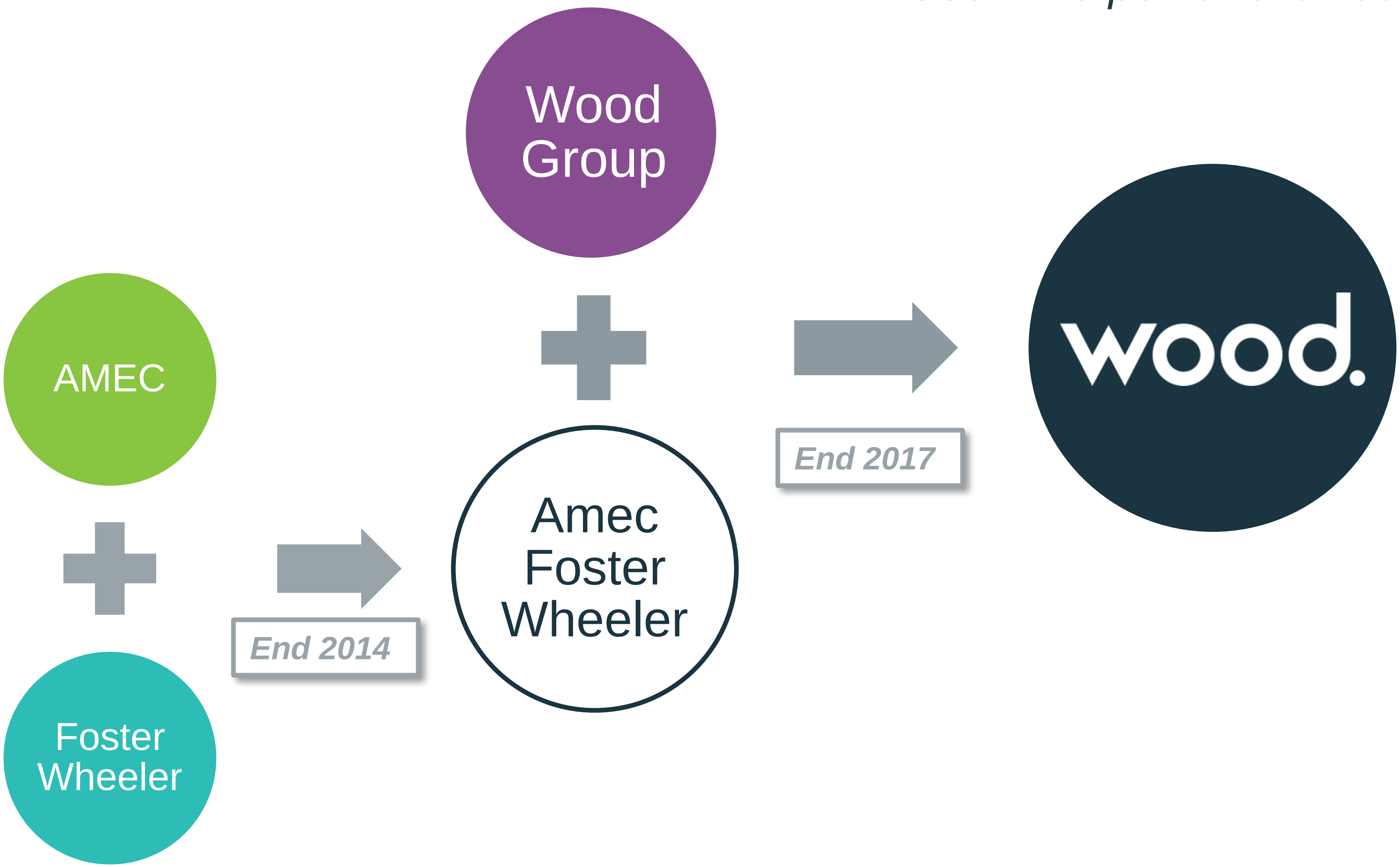
EFC WP15 Spring Meeting

03 May 2018, Tenaris - Dalmine

Introduction to Wood.

Schematic history of the new group

Wood. *The power of three*



Wood facts…

160+
Year history

55,000
People

60+
Countries

400+
Offices

- Clean Energy
- Chemical
- Refining
- Environment and Infrastructure
- Manufacturing
- Marine and Defence
- Mining and Minerals
- Nuclear, Power and Process
- Oil & Gas

Design & Engineering

Procurement, Construction & Commissioning

Maintenance & Repair

Modification & Upgrade

Decommission & Disposal

Wood Italian office…

Refining & Downstream

Power plants

Pharma / Biotech

Environment

Oil & Gas

Chemicals

Mining and Minerals

Engineering & Design
- Studies
- Concept
- FEED
- Detailed Design
- Grassroot / Brown field

Build
- Procurement
- Construction
- Commissioning
- Start-up

Improve
- Modifications
- Upgrades
- Optimisation
- Project management
- PMC

60+
Years experience
(in Milan since 1957)

800
Currently ~800
employees

800+
Plants and Process
Heaters designed

Background

MIC in Material Selection activity for refinery plants

Background

Considered Scenarios

- Normal operating process fluid
- Normal operating & design conditions /Temp. Press.)
- Possible Upset (both fluid & temp./press.)
- Transient Conditions (start-up / shutdown)

Material Selection Activities

Results

- Choice of suitable material of construction
- Special and additional requirement for material, fabrication, handling to avoid corrosion and failure

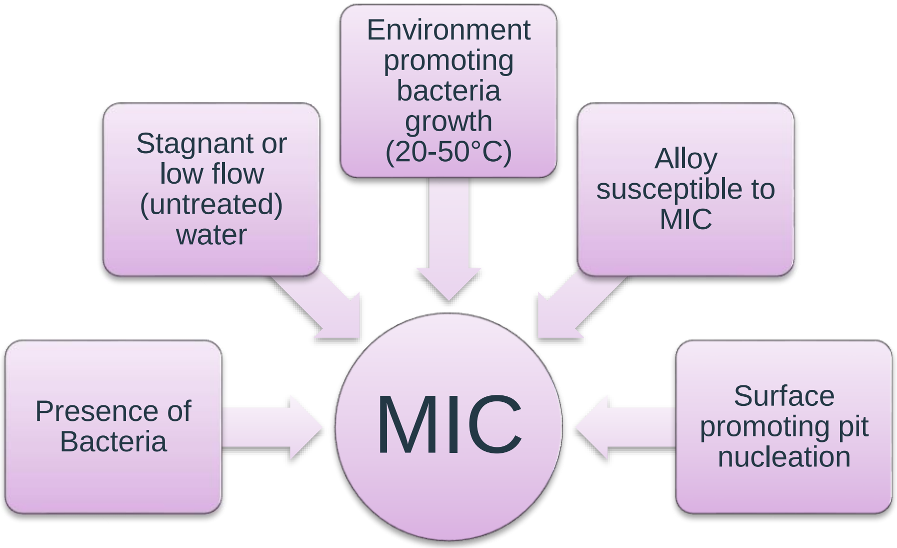
A recent experience highlighted

the importance of material preservation

To avoid contamination and corrosion during

fabrication & pre-commissioning activities

Background



MIC rarely occurs in Refinery plant as a consequence of **process operations**

- Water is usually flowing and chemically treated (e.g. WWT or CW systems)
- Where stagnant water is expected, proper coating is specified (e.g. water tanks)

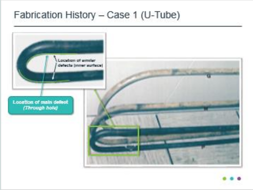
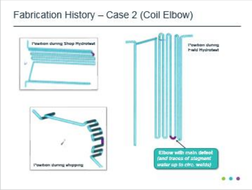
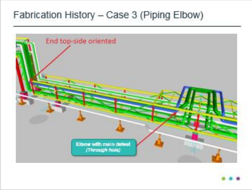
Over the years we experienced 3 cases of MIC damage related to:

- Surface treatment
- Hydrotest operation
- Transportation and Erection

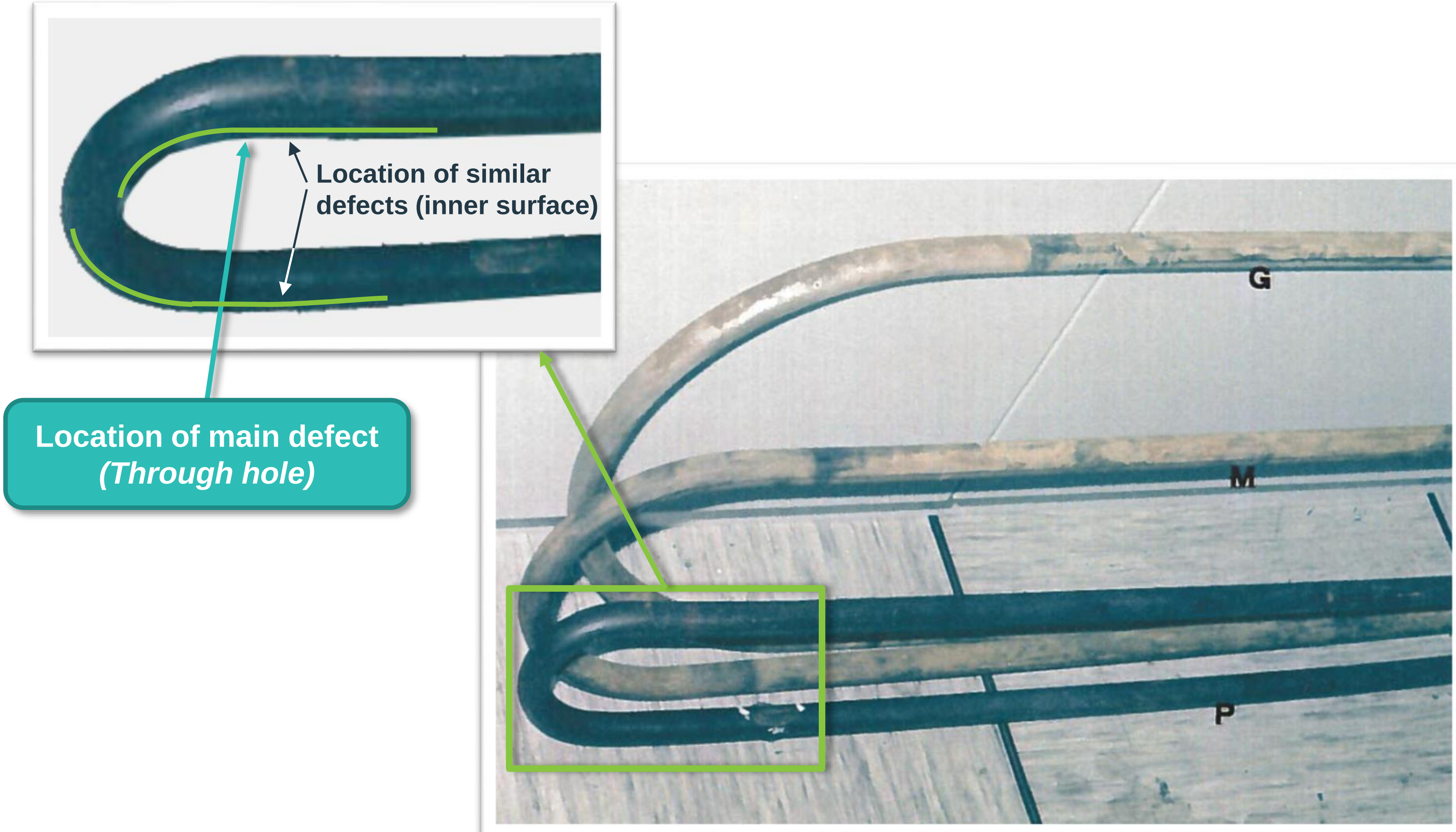
Failure cases

Analysis and comparison of 3 failures over 20 years

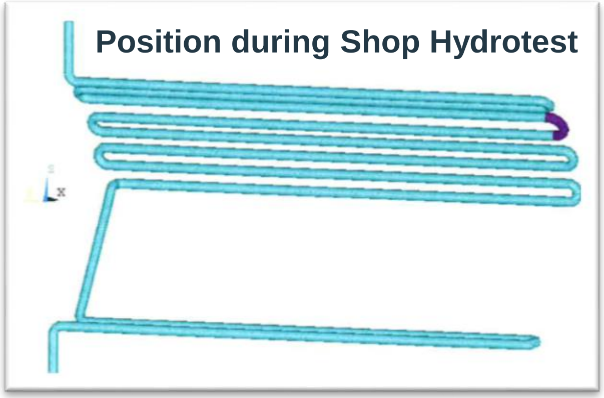
Fabrication History

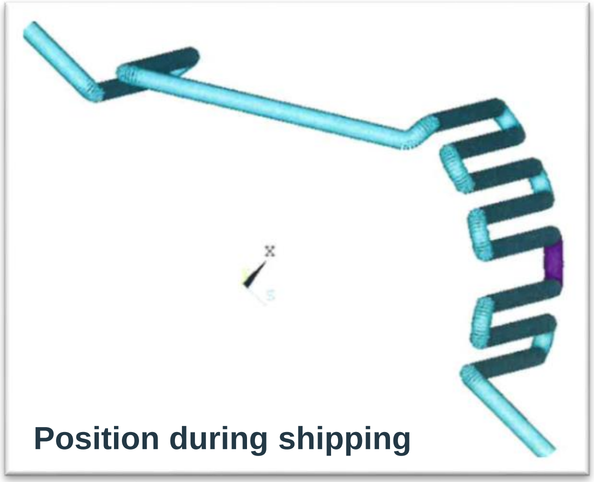
	Case 1	Case 2	Case 3
Component	H.E. U-bend Tube	180° Elbow - Fired Heater Radiant Coil	90° Elbow – Piping line
Material	SS 321	A403 WP 347	A403 WP 304L
Fabrication	SMLS Tubes bent & stress relieved	Wrought SMLS NPS 5 x 6.5 mm	Wrought SMLS NPS 8 x 9.6 mm
History	Shop Hydrotest Delivering on site **Pickl./Passiv./Rinsing** on TS Hydrotest ShellSide → FAILURE	Shop Hydrotest (horiz. pos.) Shipment (horizontal pos.) **Field hydrotest** (vertical pos.) NDE (RX) → FAILURE	**Shop Hydrotest** **Sea shipment** (heavy storm) **Site Bevelling** (ends left open) Site hydrotest → FAILURE
Layout			

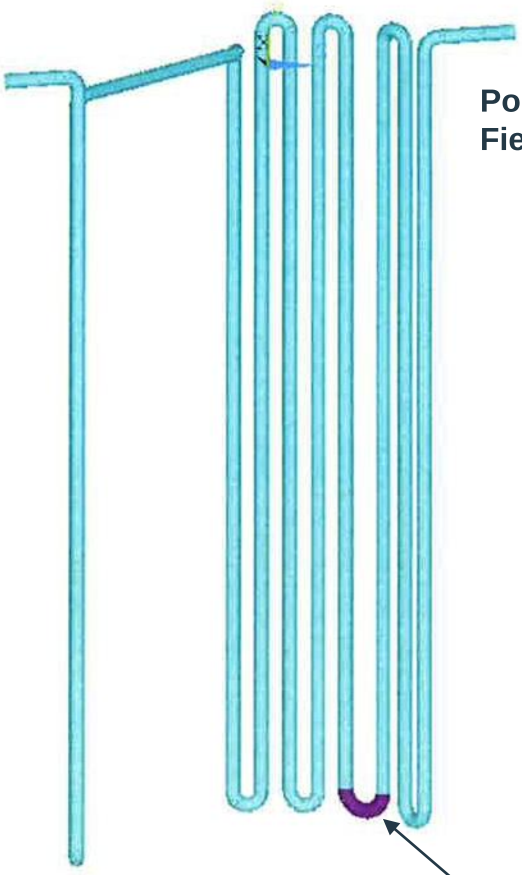
Fabrication History – Case 1 (U-Tube)



Fabrication History – Case 2 (Coil Elbow)



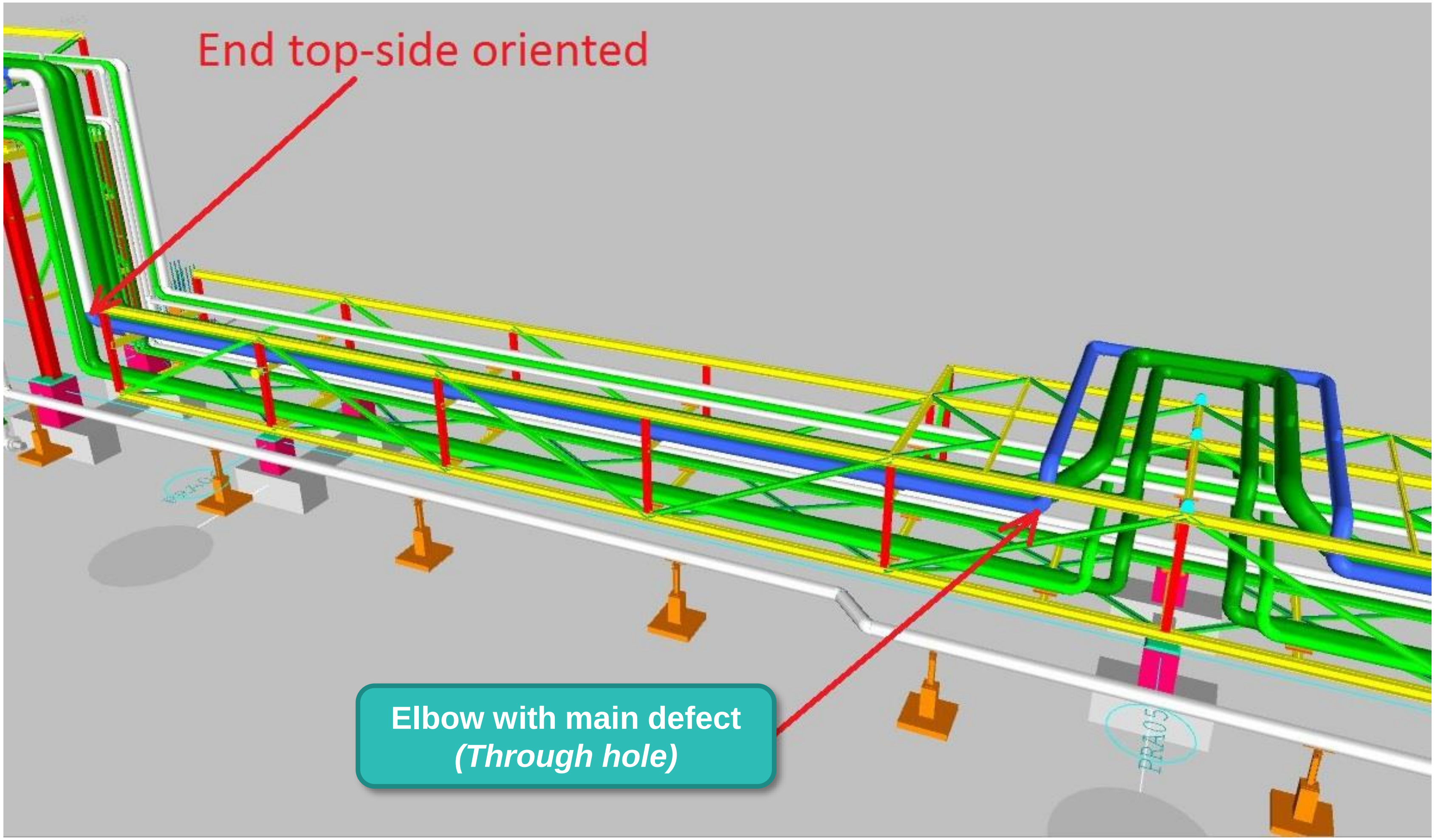




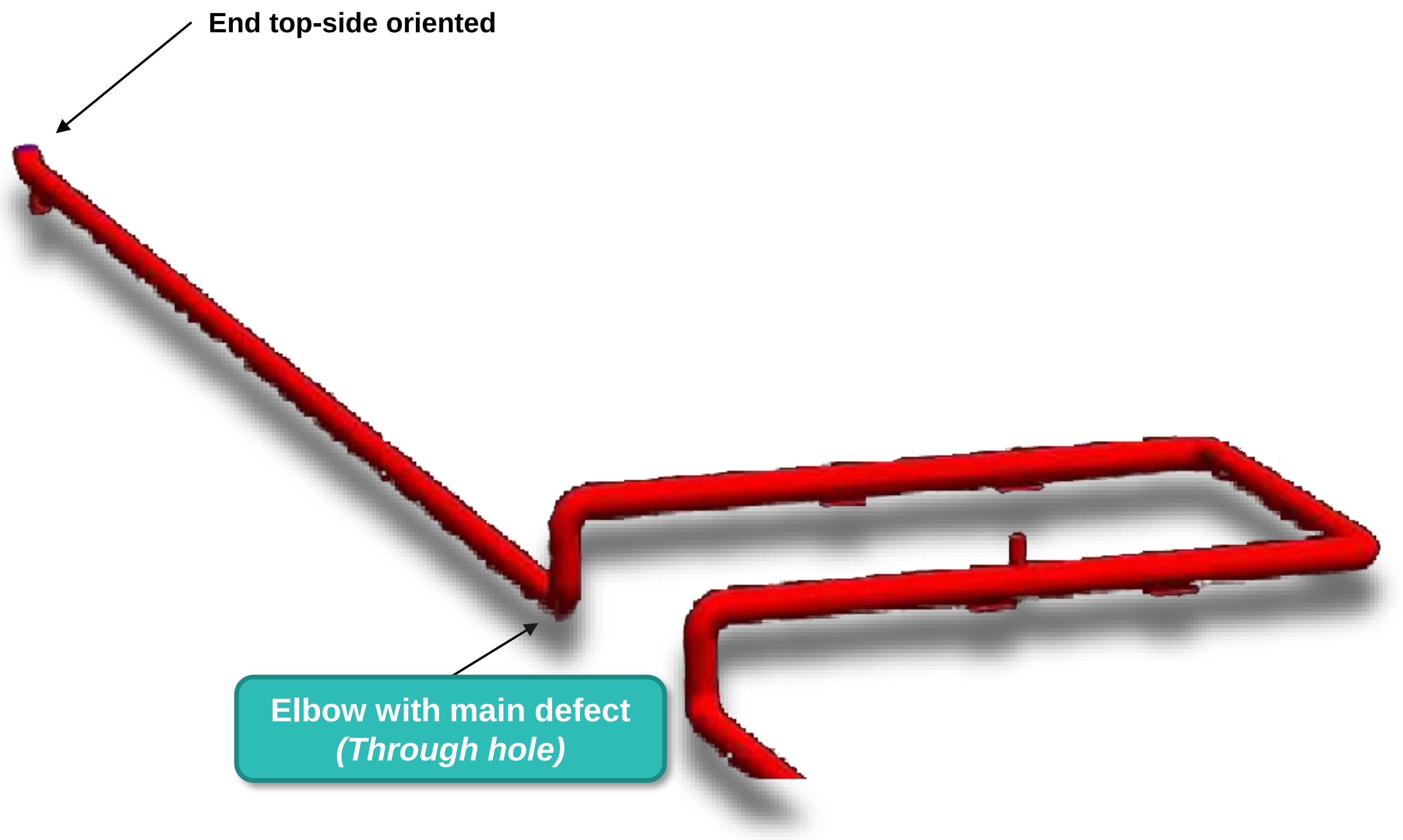
Position during
Field Hydrotest

Elbow with main defect
(and traces of stagnant water up to circ. welds)

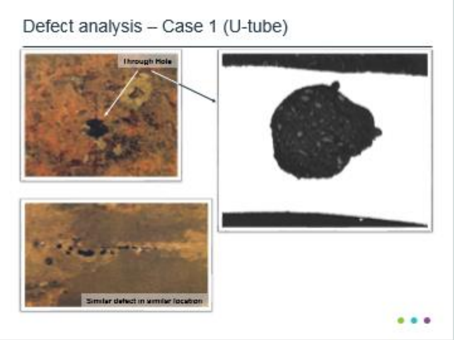
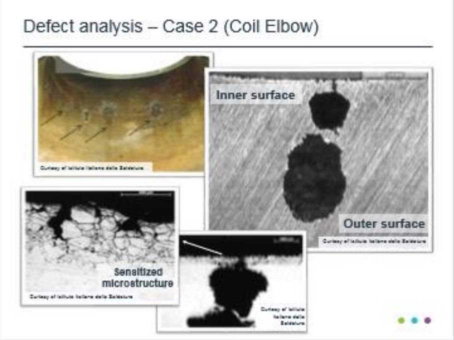
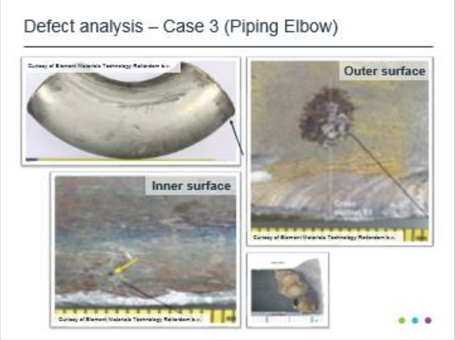
Fabrication History – Case 3 (Piping Elbow)



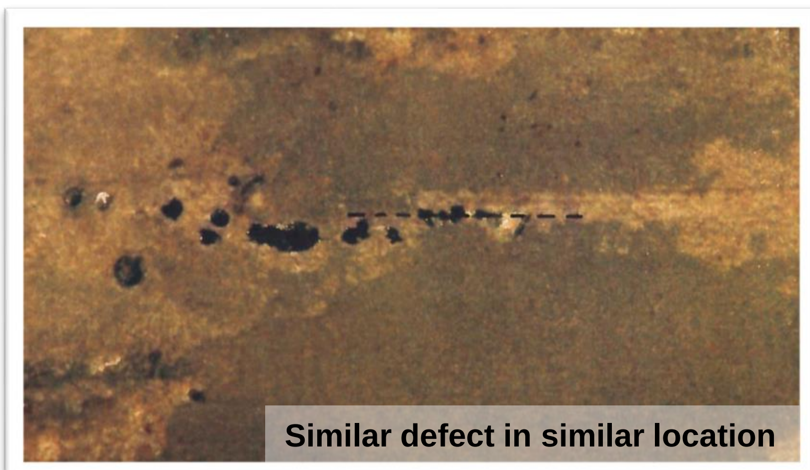
Fabrication History – Case 3 (Piping Elbow)



Defect analysis

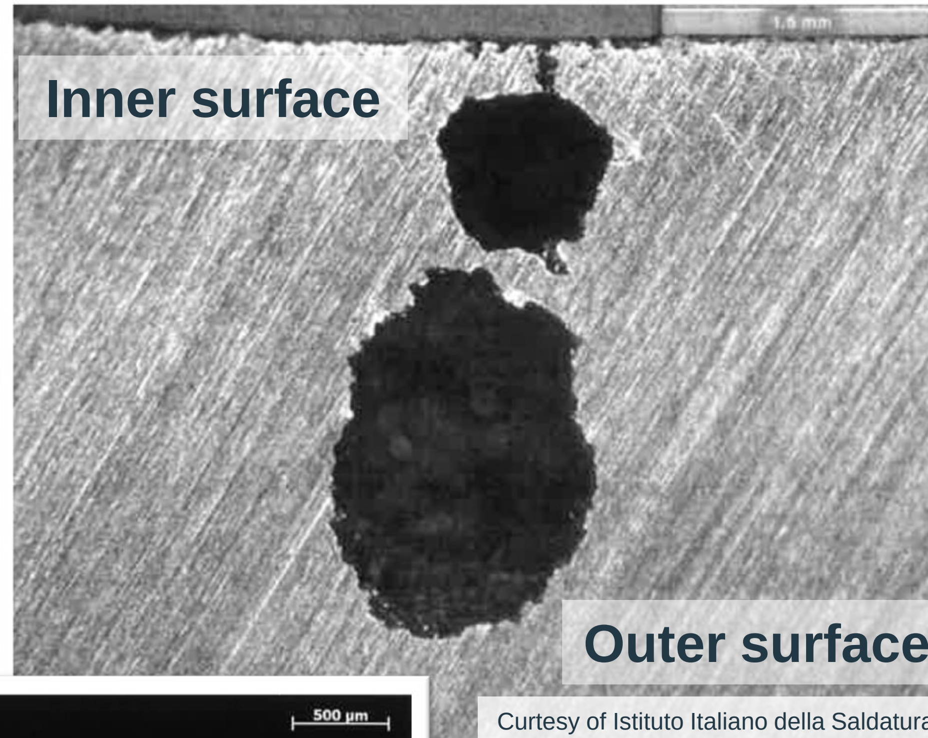
	Case 1	Case 2	Case 3
Defect			
Position	Intrados	Intrados	Extrados
Type	Through hole	Deep occluded pit	Through hole
Morphology	**Occluded cavern pit**, **needle shaped walls**, **small starting hole** (Ø ~0.5 mm)		
Notes	Most corr. indication on the 6h lines	Traces of stagnant water (elbow full of water)	Traces of stagnant water (water pool)

Defect analysis – Case 1 (U-tube)



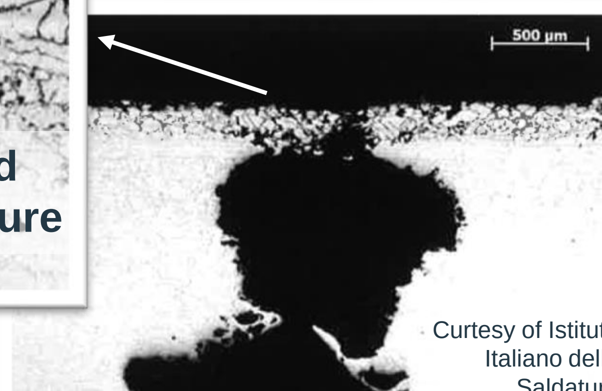
Defect analysis – Case 2 (Coil Elbow)


Curtesy of Istituto Italiano della Saldatura



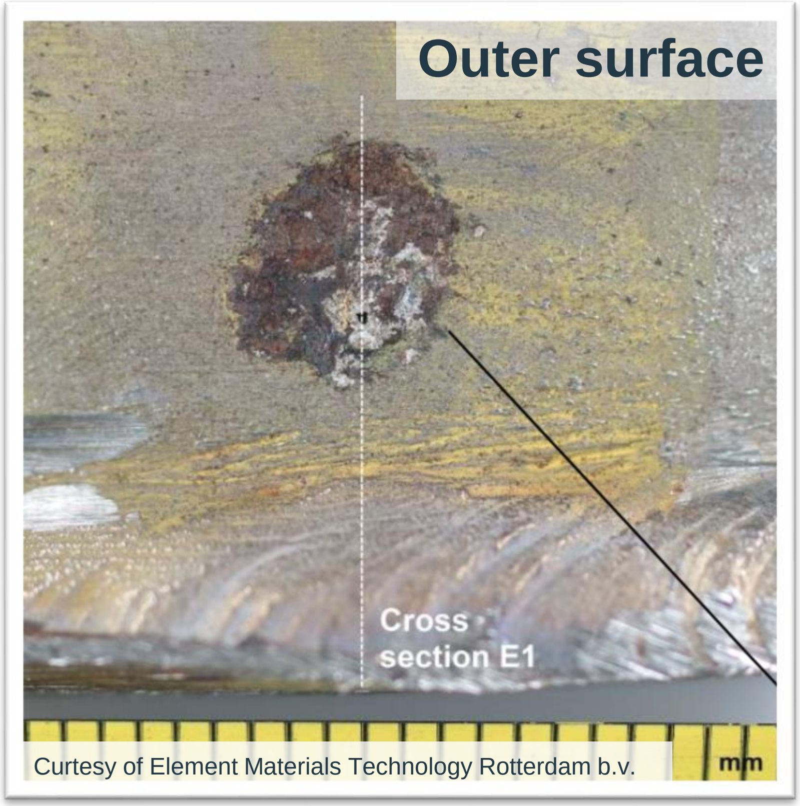
Curtesy of Istituto Italiano della Saldatura

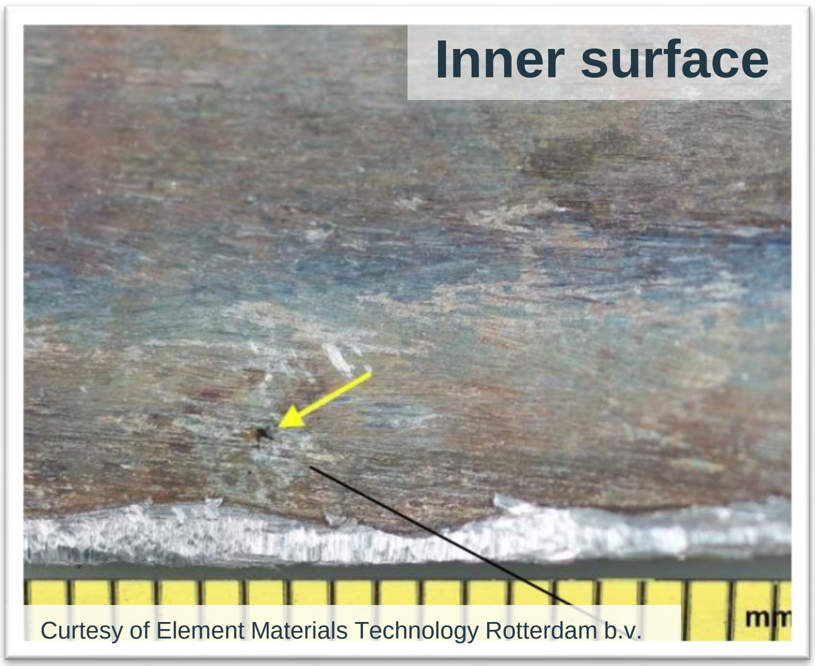
Curtesy of Istituto Italiano della Saldatura

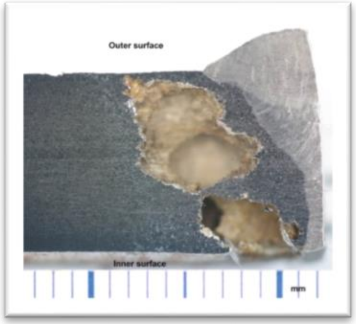


Curtesy of Istituto Italiano della Saldatura

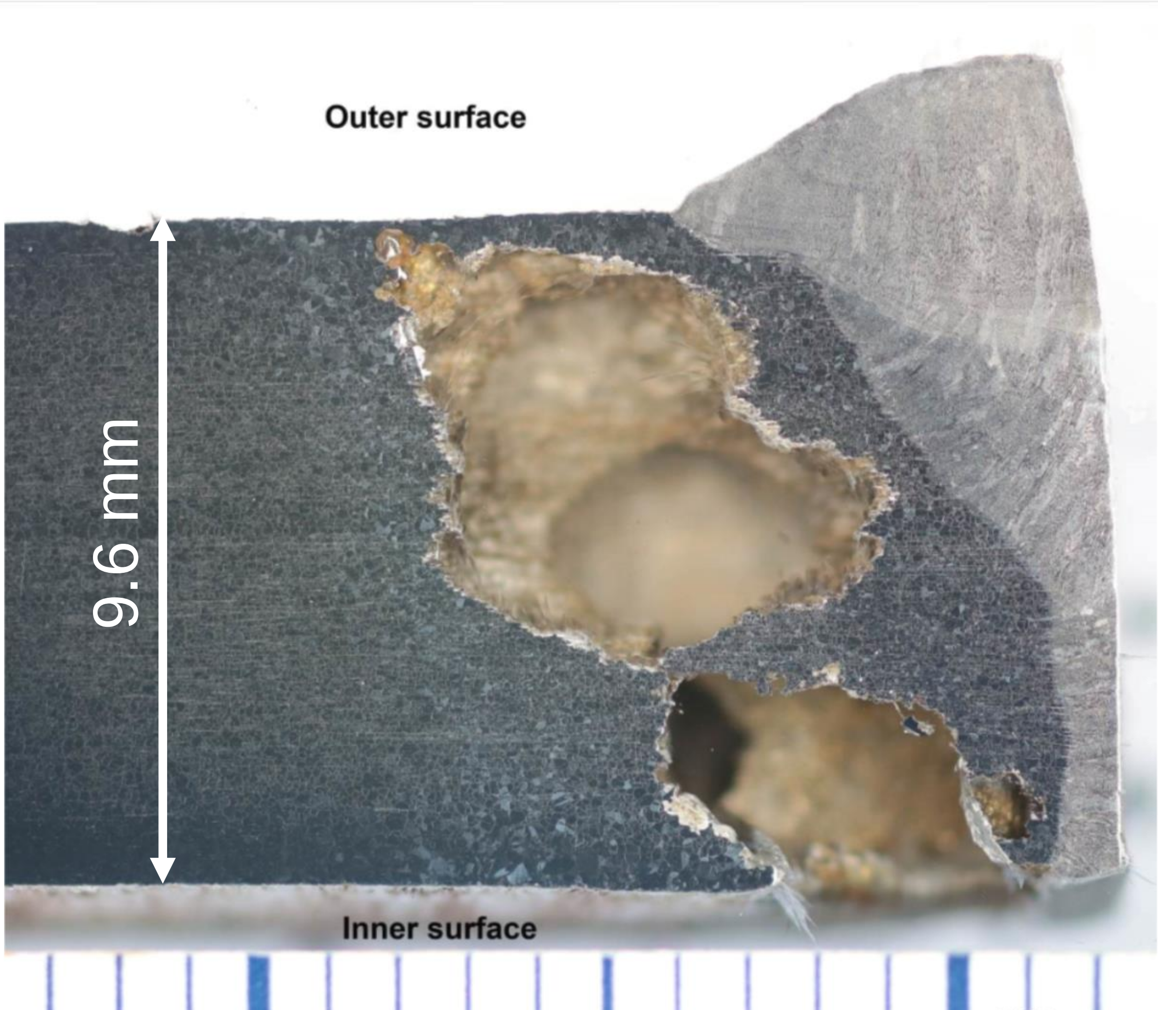
Defect analysis – Case 3 (Piping Elbow)







Defect analysis – Case 3 (Piping Elbow)



Curtesy of Element Materials Technology Rotterdam b.v.

Defect analysis

	Case 1	Case 2	Case 3
Pit nucleation	*(Not identified)*	Non-homogeneous grain dimension (due to bending)	High residual stress (weld HAZ)
Corrosion products	Brown reddish deposit crown around internal hole	Brown reddish deposit haloes around internal hole	Brown reddish deposit around external hole, discoloration on inner surface
	Chlorine, Phosphorus	Sulphur	Sulphur, Chlorine
Other defects	Small pitting & local depassivation	Elongated cavities & holes	Small isolated & rounded pits
	Similar defects in similar location → onset of same type of corrosion as main defect		
Notes	All corr. indication **where water pool was likely**		

Corrosion phenomenon	Severe Localized corrosion **(now deemed to be MIC)**	**MIC**	**MIC**
Promoting environment	High conc. Residual Chlorine	Contaminated stagnant water	Contaminated stagnant water
Water source	Surface chemical treatment	Field Hydrotest	**Not yet fully clear.**

Lessons Learnt

Awareness and attention to fabrication, pre-commissioning and non-operating conditions

Possible source of water & bacteria

Hydrotest operations (shop & field)

- Contaminated hydrotest water *(Bacteria)*
- Handling of water in contaminated facilities *(Bacteria)*
- Not fully reliable Drain & Drying method *(Water)*

Sea shipping

- Possible Sea Water entrapment *(Water & Bacteria)*
  - Missing or damaged openings protections
    - Improper handling or heavy storm

Storage & Erection operations (shop & field)

- Unprotected openings during storage and erection activities
  - Collection of debris in stored materials *(Bacteria)*
  - Carry-over of dirt and rain water *(Water & Bacteria)*

Lessons learnt

Material

- Although in principle most of commonly used materials are susceptible to MIC, the real concern is for **Austenitic Stainless Steel**.

Water

- **Demi Water** should be used for hydrotest
- **Certificates and sampling** should be required for all batch of water

Drain & Drying

- Review of Contractor's **procedure for drain & drying**
- **Piping design** to be fully drainable in hydrotest condition
- Pigging or biocide injection where complete drying is not assured

Open Ends

- All **openings shall be always protected** (fabrication, shipping, storage)
- Ends protections shall be **immediately restored after any works**
- **Check for integrity of protection** caps shall be planned

Sea Ship.

- **Sea shipping** requires additional care:
  - **Handling** during loading/unloading operations
  - Check after **heavy storm** during shipping

Appendix 14

Influence of fluorides leak on cooling system corrosion (case study)

(V. Bour-Beucler)

Eurocorr WP15 Spring Meeting

Case study regarding fluorides leak in cooling water systems

Dalmine May 3rd

Background

- Refinery in Middle East after turn around
- 4 recirculating cooling systems feed with reuse water (soft water with high level of chlorides and sulfates).
  - Stress conditions are make up water quality
- Start up without heat exchangers passivation
  - High soluble iron level (>15mg/L)
  - SRB spot measurements at 40

- Carbon steel heat exchangers and small part of copper alloys.
- Leak of fluorides in reuse water tank over 100 mg/L
  - Heat exchangers cleaning process side (alkylation)

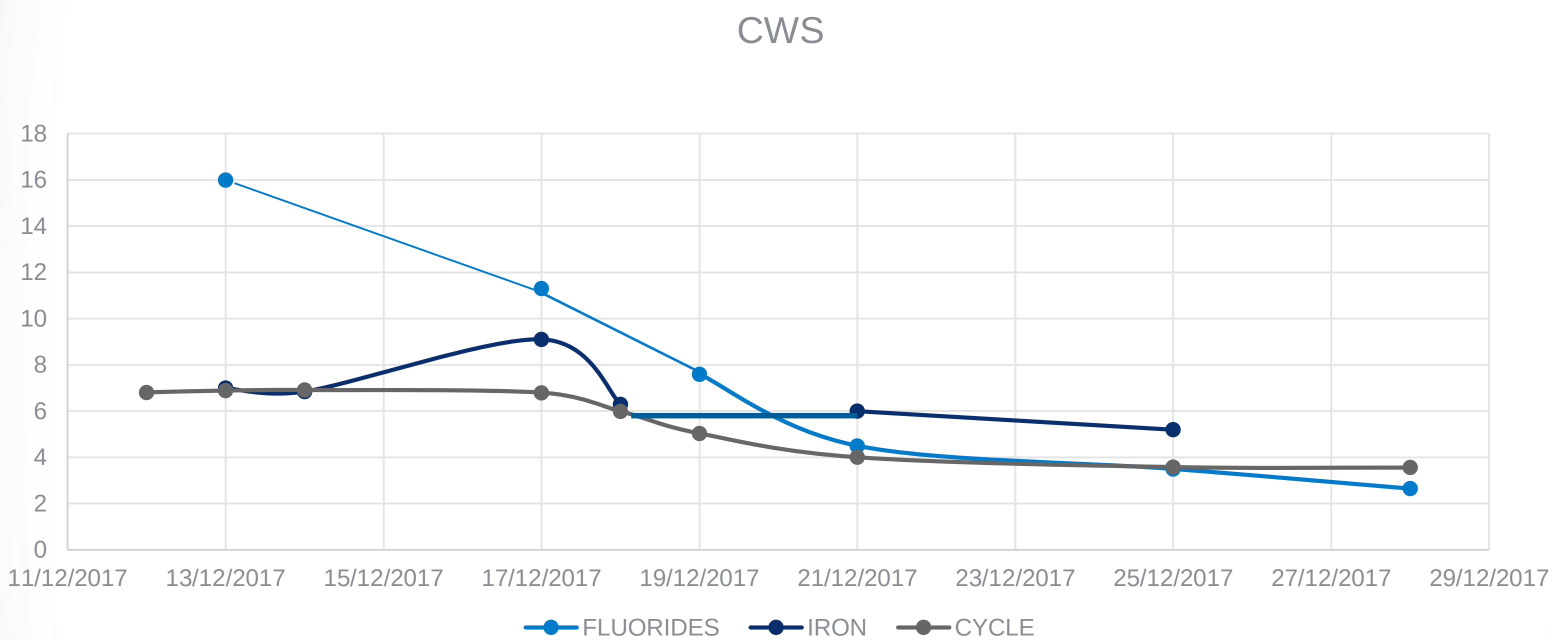
Consequence and direct impact

- Carbon steel corrosion high increases
  - several mm/an
  - Fouling and deposit
- Blowdown increase (water and treatment consumption)
  - Economical impact
  - Water limitation
- Biofouling and mineral fouling in low velocity part of the system.
- Overconsumption of anodic corrosion inhibitors (OPO4)

Root causes analysis

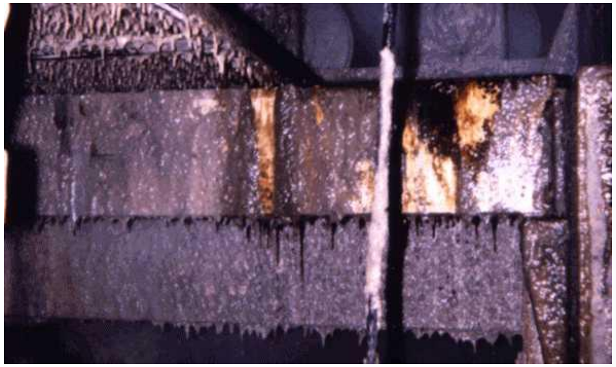
- Unpassivated cooling water system and unpassivated heat exchangers
  - High level of iron
    - ACTIVE CORROSION
- Présence of fluorides
  - Iron fluoride formation and corrosion increase (agressive ions)
  - Iron oxide and iron fluoride fouling
  - Complexing cleaning solution process side (NTA) cooling water system impact (copper transportation)
- SRBs
  - Growth in the deposit and localized corrosion formation
- Under deposit corrosion
- Biofilm growth non adapted oxidizing biocide

Iron and fluorides follow up



Heat exchanger tubes

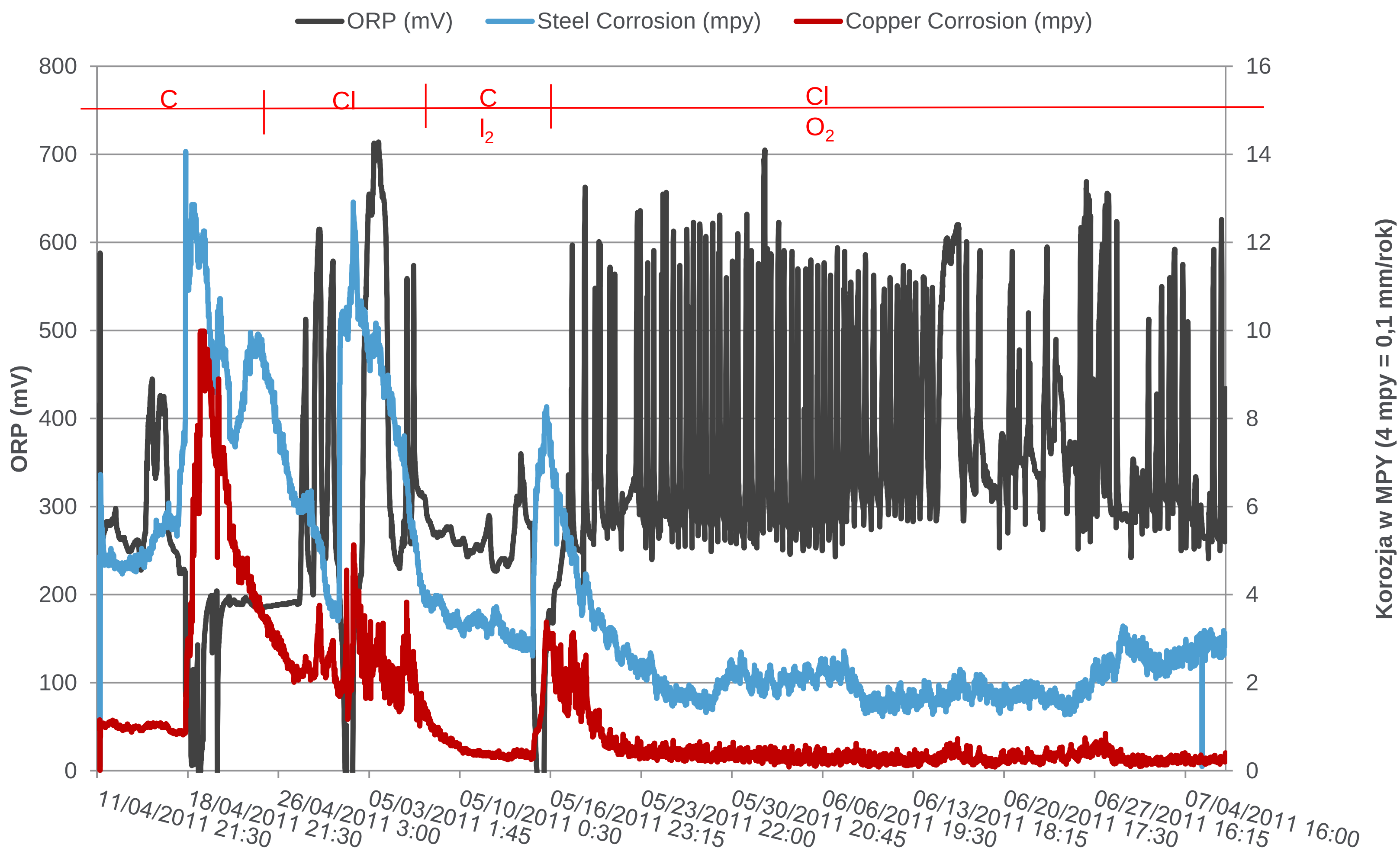
Deposit with mainly iron fluoride



Action plan

- Replacement of reuse water by city water
- Blowdown to maintain low fluorides level
  - Fluoride <3mg/L
- Critical heat exchangers shutdown and cleaning
- Reuse water Pre chlorination with chlorine dioxide (Purate system)
- Cooling system passivation with PSO (corrosion inhibitor).

ClO2 and corrosion



NALCO Champion
An Ecolab Company

Purate case study results

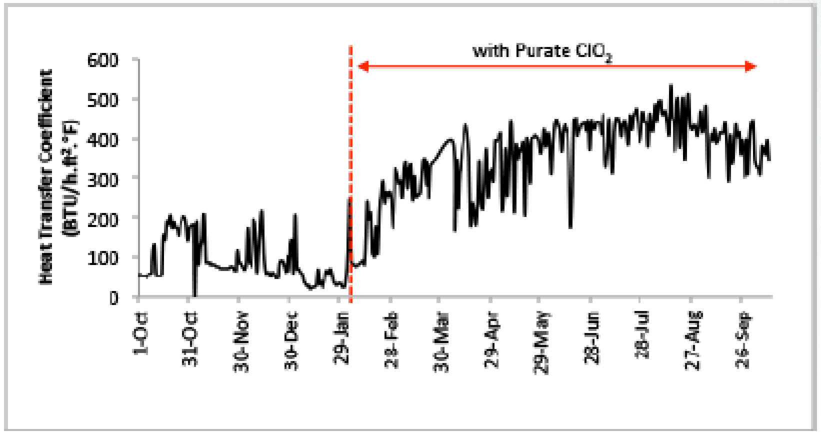


Figure 3: MED train C heat transfer coefficient improvement

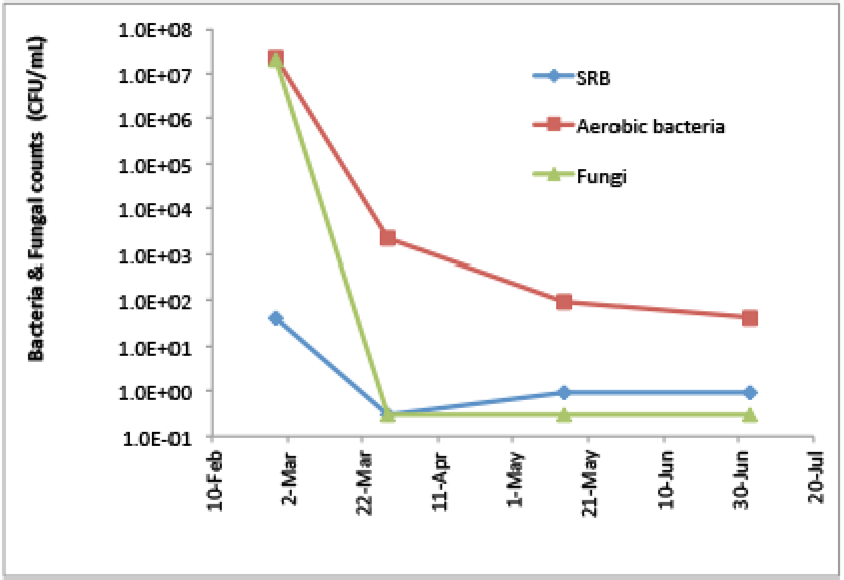


Figure 2: Microbial and fungal counts in seawater system