Appendix 1

List of participants

Participants EFC WP15 meeting 11th September 2019 Seville (Spain)

NAME	SURNAME	COMPANY	COUNTRY
Al Aithan	Jehad	Saudi Aramco	SAUDI ARABIA
Al Musharfy	Mohamed	ADNOC Refining Research Center	UNITED ARAB EMIRATES
Bateman	Colin	IGS	UK
Bhamji	Imran	TWI	UK
Chmielarski	Jarema	Armacell	POLAND
Claesen	Chris J	Nalco Champion	BELGIUM
De Landtsheer	Gino	Borealis	BELGIUM
Dean	Frank	Ion Science Ltd	UK
Demma	Alessandro	Omnia Integrity	SPAIN
Dodelin	Laure	Total Refining & Chemicals	FRANCE
Escorza	Erick	Tenaris Dalmine	ITALY
Fischbacher	Peter	Emerson Automation Solutions	ITALY
Fullin	Luna	Tenaris Dalmine	ITALY
Gregoire	Vincent	Equinor	NORWAY
Hasek	David	ATI Metals	USA
Hofmeister	Martin	Bayernoil Raffineriegesellschaft mbH	GERMANY
Holmes	Briony	TWI	UK
Houlle	Patrice	Patrice Houlle Corrosion Service - MTI	FRANCE
Höwing	Jonas	Sandvik	SWESEN
Kawakami	Tadashi	Nippon Steel European Office	GERMANY
Kus	Slawomir	Honeywell	UK
Lasarte	Carlos	Combustión, Energía & Ambiente, S.A.	SPAIN
Lee	Chi-Ming	TWI	UK
Lheureux	Mathieu	NEOTISS	FRANCE
Lorkin	David	Ionix Advanced Technologies	UK
Lucci	Antonio	Rina Consulting	ITALY
Maddi	Mohamed	ADNOC Refining	UNITED ARAB EMIRATES
Madeddu	Enrico	SARTEC SARAS	ITALY
Magel	Chis	PPG Protective & Marine Coatings	UK
Magel	Chris	PPG Protective & Marine Coatings	BELGIUM
Monnot	Martin	Industeel	FRANCE
Olahova	Natalia	Kubota Materials	CANADA
Onodera	Yoichi	Mitsui & Co Ltd	JAPAN
Prencipe	Roberta	Rina Consulting	ITALY
Rangel	Pedro	CEPSA	SPAIN
Rodriguez Jorva	Javier	CEPSA	SPAIN
Ropital	François	IFP Energies nouvelles	FRANCE
Schempp	Philipp	Shell Deutschland Oil GmbH	GERMANY
Serra	Mario	SARLUX	ITALY
Sharma	Prafull	Corrosion RADAR	UK
Soltani	Askar	South Pars Gas Complex	IRAN
Suardi	Edoardo	SARLUX	ITALY

Suleiman	Mabruk	ADNOC Refining Research Center	UNITED ARAB EMIRATES
Surbled	Antoine	A.S – CORR CONSULT	FRANCE
Tabaud	Frederic	BP RTE	NETHERLANDS
Ulm	Philipp	Bayernoil Raffineriegesellschaft mbH	GERMANY
Van Rodijnen	Fred	Oerlikon metco	GERMANY
van Roij	Johan	Shell Global Solutions International B.V.	NETHERLANDS
Vlad	Gogulancea	LUKOIL Neftochim Bourgas JSC	ROMANIA
Zhang	Jian-Zhong	SABIC	UK
Zlatnik	Ivan	MITSUI & Co Deutschland	CZECH REPUBLIC

Appendix 2

EFC WP15 Activities

(Francois Ropital)

EUROPEAN FEDERATION OF CORROSION

EFC Working Parties

http://www.efcweb.org

- WP 1: Corrosion Inhibition
- WP 3: High Temperature
- WP 4: Nuclear Corrosion
- WP 5: Environmental Sensitive Fracture
- WP 6: Surface Science and Mechanisms of corrosion and protection
- WP 7: Education
- WP 8: Testing
- WP 9: Marine Corrosion
- WP 10: Microbial Corrosion
- WP 11: Corrosion of reinforcement in concrete
- WP 12: Computer based information systems
- WP 13: Corrosion in oil and gas production
- WP 14: Coatings
- WP 15: Corrosion in the refinery and petrochemistry industry
  (created in sept. 96 with John Harston as first chairman)
- WP 16: Cathodic protection
- WP 17: Automotive
- WP 18: Tribocorrosion
- WP 19: Corrosion of polymer materials
- WP 20: Corrosion by drinking waters
- WP 21: Corrosion of archaeological and historical artefacts
- WP 22: Corrosion control in aerospace
- WP 23: Corrosion reliability of Electronics

- Task Force on Corrosion in CO_2 Capture Storage (CCS) applications
- Task Force on atmospheric corrosion

EUROPEAN FEDERATION OF CORROSION

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://efcweb.org/WP15.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 (2020 Brussels-Belgium, 2021 Budapest-Hungary, 2022 Berlin-Germany)

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)
10 April 2019	Roma - Italy (Rina CSM)

Publications from WP15

•EFC Guideline n° 55 Corrosion Under Insulation
A revision is in progress by a task force

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

• Best practice guideline on corrosion in sea water cooling systems (joint document WP9 Marine Corrosion and WP15)
In progress by a task force

•Future publications – task forces : suggestions ?
  •best practice guideline to avoid and characterize stress relaxation cracking ?

Information :
Future conferences related to refinery corrosion

15-19 March 2020
CORROSION 2020 NACE Conf Houston Texas

6-10 September 2020
EUROCORR 2020 Brussels Belgium

19-23 September 2021
EUROCORR 2021 Budapest Hungary

4-8 September 2022
EUROCORR 2022 Berlin Germany

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

Best practice guideline on corrosion in sea water heat exchangers systems

1- Introduction **M. Suleiman** (chapter leader)

2- Main seawater heat exchangers systems and other uses, **M. Suleiman** (chapter leader)**,** V. Bour-Beucler (contributor)

3- Seawater environment: aggressivity, living organisms, deposits and scale formation, pretreatment **A.M. Grolleau** (chapter leader) *.* M. Suleiman

4- Different forms of corrosion in sea water heat exchangers systems (galvanic, crevice, erosion…) **A.M. Grolleau** (chapter leader), F. Ropital

5- Biocide treatments (chlorination) – how they can affect the corrosion resistance **V. Bour-Beucler** (chapter leader) A.M. Grolleau, P. Bleriot

6- Corrosion and scale inhibitors **P. Bleriot (**chapter leader)

7- Corrosion tests **A.M. Grolleau** (chapter leader)

Best practice guideline on corrosion in sea water heat exchangers systems

8- Materials used **A. Surbled** (chapter leader)
- Carbon steels and coating and concrete A. Surbled F. Dupoiron
- Stainless steels D. Thierry, A.M. Grolleau A. Philipp
- Nickel base alloy D. Thierry, A.M. Grolleau , A. Philipp
- Copper alloys A.M. Grolleau
- Aluminium, Titanium alloys A. Surbled F. Dupoiron
- Plastics , composites, non metallic J.M Daubenfeld, M. Suleiman

9- Corrosion protection **J.Z. Zhang** (chapter leader)
- Material selection to avoid galvanic corrosion J.Z. Zhang
- Coatings J.Z. Zhang
- Corrosion control by use of cathodic protection A.M. Grolleau, J.Z. Zhang

10-Maintenance and tube cleaning **F. Dupoiron** (chapter leader) J.Z. Zhang A. Surbled,

11- Control and monitoring, inspection techniques **A. Surbled** (chapter leader)

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

Integrity operating window in amine units

(Askar Soltani)

Integrity operating window in amine

Askar Soltani

South Pars Gas Complex, Inspection Department, Asaluyeh, Iran

askarsoltani824@gmail.com

Introduction

One of the most challenging issues in amine units is to find out the basic culprit and prove its effect as the main corrosive component. However corrosive agents such as HSAS (Heat Stable Amine Salts), amine degradation byproducts, oxygen ingress and acid gases can play the main role in corrosion scenario in amine units but there is another hidden player which sometimes stands in safe side and takes no responsibility of not being within the limits of IOW (Integrity Operating Window) as shown in figure 1, and doesn't accept its role in this kind of corrosion. After observing severe corrosion in the bottom of regenerator and also the reboiler of AGE unit, it was decided to conduct a root cause analysis by further internal inspection in other trains, reviewing the operational conditions and also amine solution laboratory analysis. Comparing operational conditions in different amine treating units revealed that the rich amine inlet temperature into the regenerator column was lower than the design value due to the problems in lean/rich cross exchangers. In order to compensate the low temperature in the top portion of the stripper column the operator increased steam rate into the reboiler and the elevated temperature was exceeded the maximum allowable temperature for steam which increased the probability of thermal degradation of amine in the bulk solution. Lab results revealed that the amine was degraded and the content of HSAS were considerable. Comparing the corrosion extent in different amine treating units revealed that however amine solution in all of the trains were degraded but the corrosion was observed in trains with poor operating conditions (i.e. low temperature of rich amine feeding into the regenerator column).

Methods

To investigate the root causes of amine corrosion two methods followed:

- Internal closed visual inspection
- Laboratory analysis of amine solution

A closed visual inspection was conducted in the first overhaul of the AGE (Acid gas Enrichment) unit in sulfur recovery plant. Severe corrosion with more than 3 mm of metal loss was observed on the bottom portion of the regenerator column (from the bottom dish end up to the chimney trays) and also on the side locations of the regenerator reboiler and some parts of weir plate. Further internal inspections were conducted in six other trains in gas sweetening units in order to compare the conditions from corrosion points of view. The corrosion was observed in only one of these trains. Samples were taken from suspected amine solutions in order to do more laboratory analysis. Comparative lab results in different amine units have been illustrated in figure 3.

Figure 1: Comparison of corrosion extent in different amine treating units: a) Chimney tray area of GTU1, b) Chimney tray area of GTU 3, C) Chimney tray area of GTU4, d) Chimney tray area of GTU 5, e) Chimney tray area of GTU 6 , f) Chimney tray area of SRU

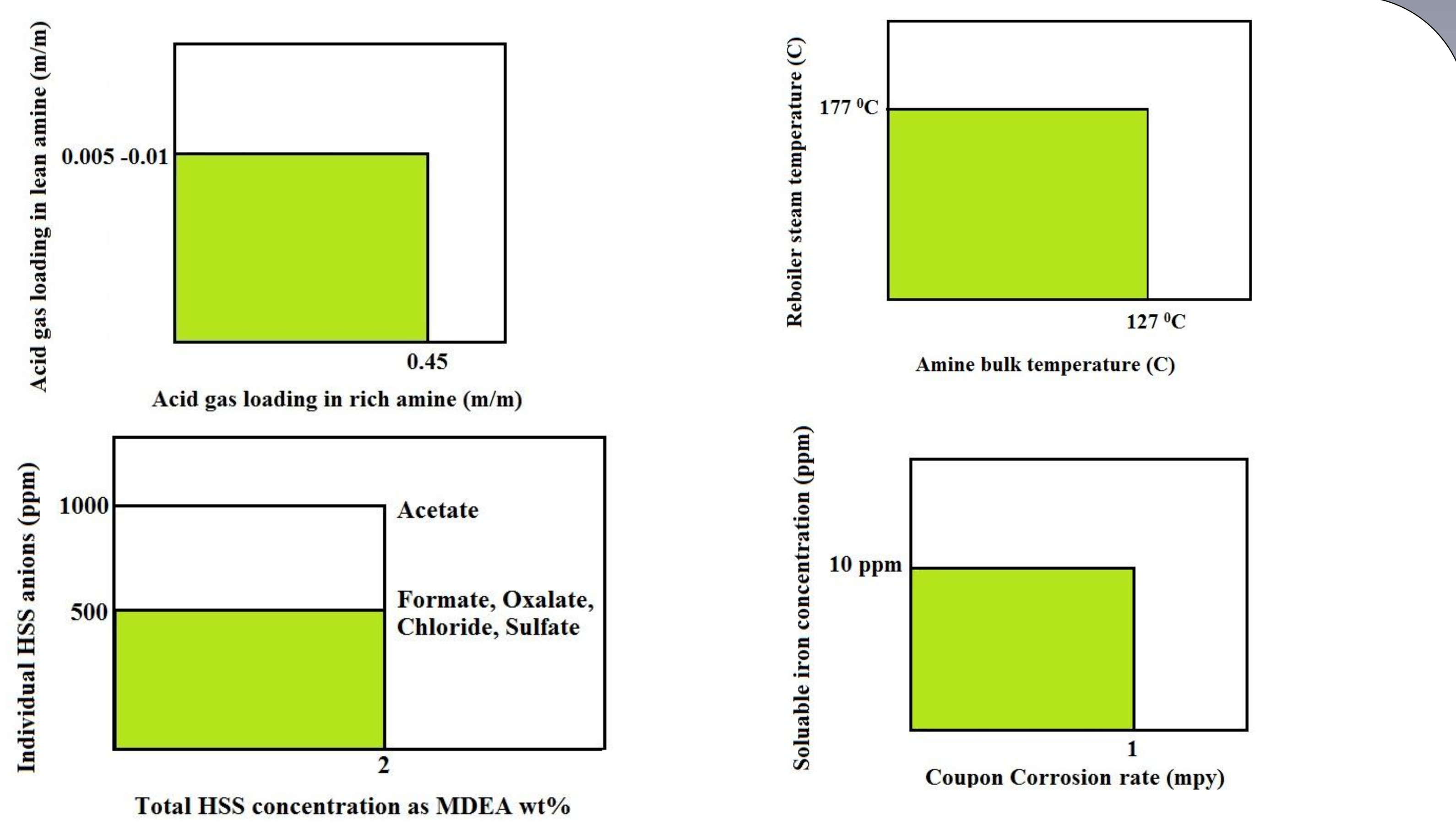

Figure 2: Some important IOW in amine units

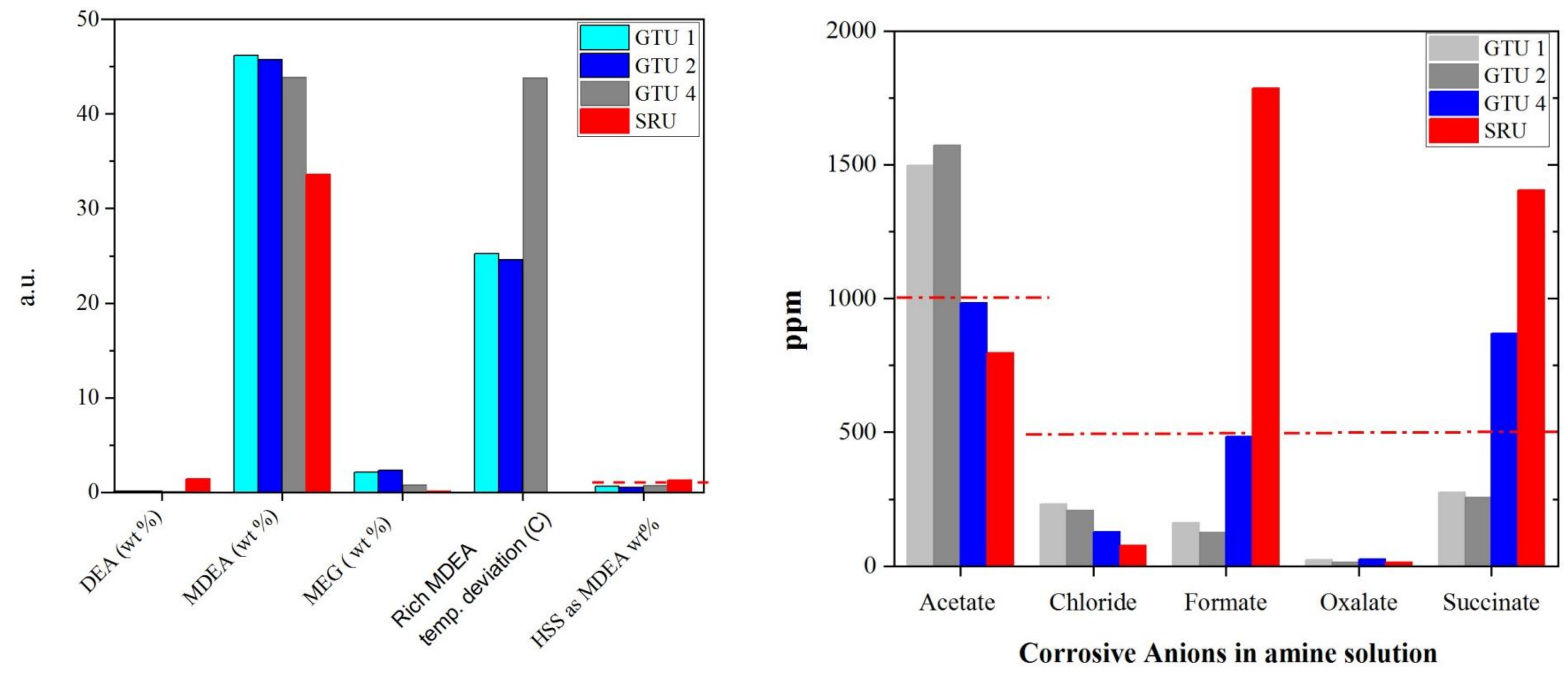

Figure 3: Comparative plots of amine specification in different amine treating units

Results

Results of internal inspection and laboratory analysis were as following:

- However almost all the amine solutions in different treating units were degraded but corrosion was occurred only in 2 number of trains with more deviation in rich amine inlet temperature to the stripper column
- Corrosion in the reboiler was more severe compared to the regenerator bottom
- Considerable amount of DEA in the amine solution of AGE unit revealed thermal degradation of amine due to elevated temperatures because of excessive steam flow during a short period of time
- In corroded units the concentration of formate and acetate anions were considerably more than other trains
- It seems that acetate anion compared to formate and succinate is less effective on corrosion in amine units

Conclusions

Conclusions from our research categorizes as following:

- Comparing the corrosion extent in different amine treating units revealed that however amine solution in all of the trains were degraded but the corrosion was observed in trains with poor operating conditions (i.e. low temperature of rich amine feeding into the regenerator column).

- Due to the safety problems, retrieving the corrosion coupons is not applicable during the operation of amine units, so we need to have an applicable inspection plan in reasonable intervals. But a big question arises here and that is what interval is reliable before the corrosion occur after the last inspection? Is it reliable to plan future inspection based on the last inspection history ? This question has a simple response which highlights the necessity of establishing and implementing an IOW program for amine operational parameters. This is a reliable troubleshooting recommendation.

- **Without having an appropriate IOW**, the RBI program would not have its required efficiency in maintaining the integrity of equipments and it is not enough to plan the future inspections only on prior records and prior history of the equipments and understanding of the process conditions

- Our experience showed us, a continuous monitoring of process conditions is required to prevent premature failures. Inspection intervals needs to be modified based on the changes in the operational conditions and this is **an IOW program** which is able to help the inspector in this regard.

Paper ID: 227316

Appendix 4

CUI, practical approach from a coating perspective

(Chris Magel)

CUI, practical approach from a coating perspective

Content

- Corrosion under insulation and approach
- Testing of coatings serving under insultation
- Clarification of the CUI coating range
- Typical systems

Corrosion under insulation

CUI is defined as the external corrosion of piping and vessels that occurs when water gets trapped beneath insulation. CUI damage takes the form of localized corrosion in carbon and low alloy steels. Factors that affect CUI include

- Duration, frequency of exposure to moisture
- Corrosivity of the aqueous environment
- Condition of protective barriers (cladding, coating,…)
- Design
- Temperatures (-4°C to +175°C // also outside this zone!)
- Cyclic temperatures??
- Insulation type
- Climate
- Site maintenance practice
- General environment (proximity of saltwater, cooling towers,…)

API 583

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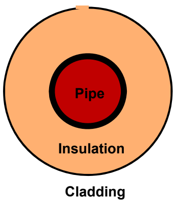
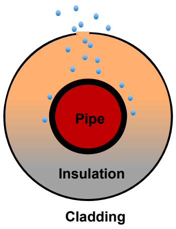
3

Corrosion under insulation

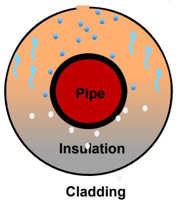
Gaps exist in cladding
- Damage
- Poor sealing
- Improper fit
- All cladding leaks eventually



Via rain, water enters the system down to the insulation and steel.



- Water boils at the pipe
- Electrolytes in the water concentrate
- Steam condenses when it reaches the cladding



Very Aggressive Corrosion

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4

Corrosion under insulation

- Nothing stays hot forever
- Water under cladding is never completely expelled
- Additional water can enter damaged cladding
- Electrolytes in the water may concentrate
- Eventually the insulation becomes saturated or will hold water (depending on insulation)

The substrate will corrode if not properly protected


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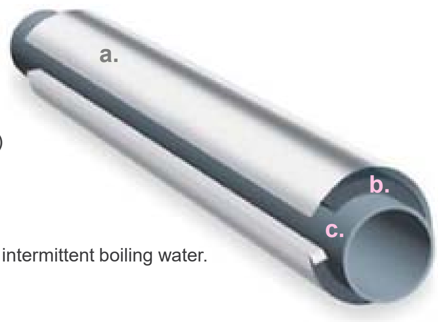
Corrosion under insulation

It is important to take all aspects of the application into account as they all are equally important to reduce the problem of corrosion under insulation. The most important aspects are

a. Sheeting
- correct sheeting selected
- correct application
- correctly sealed

b. Insulation
- reduced or no water uptake (water repellant)
- very limited chloride content
- designed to serve the purpose (not more, not less)

c. Coating
- suited for the temperature range
- immersion resistant
- able to serve under cyclic temperature conditions, intermittent boiling water.
- easy to repair if damaged
- must be able to withstand a worst case scenario



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Corrosion under insulation

Protective coating

- **Select the correct coating: This is the LAST barrier to the steel!**
- **Define temperature range,**
- **Define possible surface preparation**
- **Select coating which serves the goal!**
- **Weigh coating cost up to expected service life!**

ALL OPERATING CONDITIONS SHOULD BE CONSIDERED, INCLUDING OUT OF SERVICE STATE WHEN SELECTING THE CORRECT PROTECTIVE SYSTEM

Testing of coatings that serve under insulation

- **No specific test standard until last month**
- **Several guidelines addressing the subject of CUI**
  - API 583
  - EFC WP13 and WP14
    - These a very detailed documents addressing all aspects in mitigating CUI starting from the design phase.
    - All “last barriers” towards the steel are addressed (wrapping, TSA, coating)
    - general approach towards coatings (“conventional coating”)
  - NACE 0198-2010
    - Standard practice document (control of corrosion under thermal insulation and fireproofing materials)
    - Defines typical recommended generic coating systems based on different temperature zones

Testing of coatings that serve under insulation

Typical Protective Coating Systems for Carbon Steels Under Thermal Insulation and Fireproofing

System Number	Temperature Range [(A)(B)]	Surface Preparation	Surface Profile, µm (mil) [(c)]	Prime Coat, µm (mil) [(D)]	Finish Coat, µm (mil) [(D)]
CS-1, CS-2, CS-3	Epoxy, Fusion Bonded Epoxy, Epoxy Phenolic minus 110° to 302°F [minus 45° to 150°C]				
CS-4	-45° to 205°C (-50 to 400°F)	NACE No. 2 / SSPC-SP 10	50-75 (2-3)	Epoxy novolac or silicone hybrid, 100-200 (4-8)	Epoxy novolac or silicone hybrid, 100-200 (4-8)
CS-5	-45° to 595°C (-50 to 1100°F)	NACE No. 1 / SSPC-SP 5[15]	50-100 (2-4)	TSA, 250-375 (10-15) with minimum of 99% aluminum	Optional: Sealer with either a thinned epoxy-based or silicone coating (depending on maximum service temperature) at approximately 40 (1.5) thickness
CS-6	-45° to 650°C (-50 to 1200°F)	NACE No. 2 / SSPC-SP 10	40-65 (1.5-2.5)	Inorganic coplymer or coatings with an inert multipolymeric matrix, 100-150 (4-6)	Inorganic coplymer or coatings with an inert multipolymeric matrix, 100-150 (4-6)
CS-7	Petroleum wax primer; ambient to 140°F [60°C]				
CS-8	Shop primers and topcoats for inorganic zinc (IOZ) minus 110° to 750°F [minus 45° to 400°C] Novolac, phenolic, inorganic copolymer and inert polymeric matrix				

Testing of coatings that serve under insulation

Test standard published in DECEMBER 2018 under committee ISO TC 67 WG 11 (ISO19277)

Standard defines:

- **CUI environments**
- **Temperature ranges**
- **Specific testing to be done depending on the environment like**
- Neutral salt spray
- Water condensation test
- Immersion test (if applicable)
- Thermal cycling test
- Specific CUI test (Houston pipe test/PPG CUI chamber test,…this is still to be defined

Classification	Minimum	Peak Temperature Range		Description
CUI-1	-45ºC	-45ºC	60ºC	Wet
CUI-2	-45ºC	60ºC	150ºC	Warm
CUI-3	-45ºC	150ºC	204ºC	Hot

Testing of coatings that serve under insulation

Typical test methods for elevated temperature coatings
- **ASTM B-117:**
  - Salt Fog Chamber 3500–4500 hours
- **ASTM 2485:**
  - This test ensures adhesion based on CTE after severe thermal shock
- **ASTM 2402:**
  - Mass loss is critical in determining the porosity and longevity of a coating

Specific CUI test methods
- Shell Test; Cyclic Wet / Dry Immersion Testing 16 weeks
- Modified Houston Pipe Test 21-30 days
- ASTM G189
- PPG HTC CUI Chamber Test (1008 hours, 252 cycles)

Other tests only focus on dry exposure and/or thermal shock.

Testing of coatings that serve under insulation

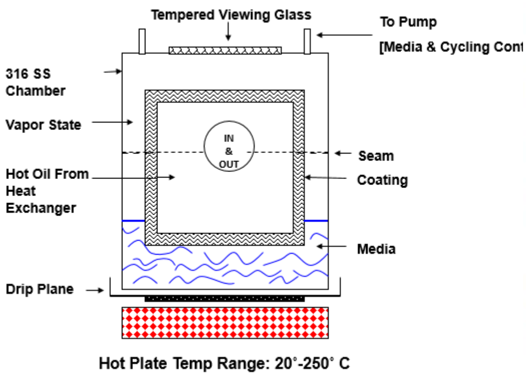
PPG CUI Chamber Test 2008

Uses ASTM G189 as a model
- For simplicity the insulation is omitted
- Temperature control: ambient to 250°C
- Consistent and repeatable results.
- The chamber environment can be totally controlled

Approvals: Shell Oil 2008, Aramco 2010

Method B:
- 5% NaCl solution
- Set wet/dry cycle time [4 hours]
- 42 day duration [252 cycles] 1008 hours
- Internal temp 350°F [179°C]
- Steam-out immersion temp 212°F [100°C]

Testing of coatings that serve under insulation



Before Test

After 6 Weeks Front View

After 6 Weeks Bottom View

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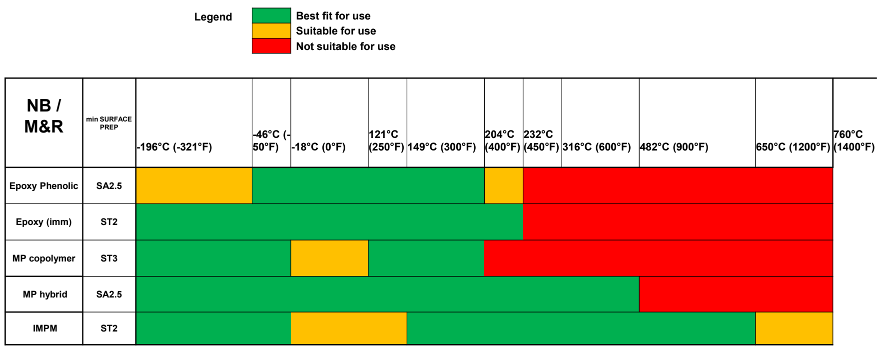
Positioning of PPG CUI coating range

CUI solutions can be classified by generic type, temperature or type of application

Generic Type	Temperature	Type of application
• Epoxy Glass Flake • Epoxy Phenolic • Multipolymeric Generic type discussions are usually held by asset owners and engineering companies. Depending on the assets, they specify technologies that will give the best protection and contribute to extending the life cycle of the assets	• Insulated assets can be exposed to extreme conditions ranging from -196°C to 650°C The operating temperature of the insulated asset will determine the type of technology needed for certain job	• New build (NB) • Maintenance & Repair (M&R) M&R scenarios might require from your solution to be surface tolerant, applicable by brush or roll, one-component material. NB scenarios will require blast cleaned surfaces and a coating less prone to mechanical damages

16

Positioning of PPG CUI coating range



17

Typical systems

INORGANIC ZINC

STRENGTHS

- **High temperature limits**
- **Good sacrificial corrosion protection**
- **SP0198 CS-8 as a bulk shop primer and when used - a top coat is recommended**

WEAKNESSES

- **Thin film coating (75µm)**
- **Corrosion can occur with zinc consumption in corrosion cell**
- **Will not survive long in wet environments**
- **Thermal shock and cycling may reduce life expectancy**
- **May suffer "reverse galvanic" corrosion between 60 and 80ºC**
- **SA2,5 absolute minimum**

Not recommended

PPG HI-TEMP™ heat-resistant coatings

Typical systems

TSA

STRENGTHS

- Mechanical bond to substrate
- High durability
- High temperature limits
- Automated application possible

WEAKNESSES

- SA2.5 absolute mimimum
- Limited suitability for maintenance
- Coefficient of thermal expansion not matched to substrate. Can lead to stress in thermal cyclic conditions
- costly

PPG HI-TEMP™ heat-resistant coatings

Typical systems

EPOXY AND EPOXY PHENOLIC

STRENGTHS

- Very good chemical resistance
- High durablity
- Hard and durable coatings
- Provides extremely good corrosion protection in immersion service

WEAKNESSES

- SA2.5 absolute mimimum
- Limited suitability for maintenance
- Coefficient of thermal expansion not matched to substrate. Can lead to stress in thermal cyclic conditions
- Temperature limitations

PPG HI-TEMP™ heat-resistant coatings

Typical systems

INORGANIC COPOLYMER – HYBRID COPOLYMER - IMPM

STRENGTHS

- Large temperature range
- CTE matches almost the substrate, so thermally durable
- Can whithstand thermal cycling
- Can whithstand thermal shock
- Surface tolerant (ST2)
- Easy to apply
- Hot application possible!

WEAKNESSES

- Slightly higher initial cost
- Moderate chemical resistance (PH5 to 10)
- Good but not best solution below 120°C

PPG HI-TEMP™ heat-resistant coatings

We protect and beautify the world™

Appendix 5

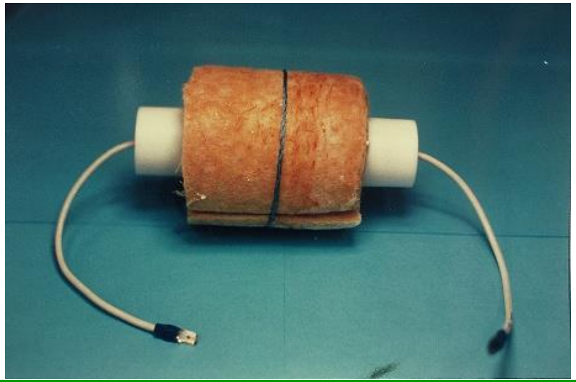
Design of probes to evaluate the performance of the different options of coatings to be used under insulation

(Carlos Lasarte)

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

The Control of Corrosion Under Thermal Insulation and Fireproofing Materials



Paper No.
438

CORROSION94
The Annual Conference and Corrosion Show
Sponsored by NACE International

EVALUATION OF PROTECTIVE COATINGS UNDER THERMAL INSULATION

AT HIGH TEMPERATURES BY THE USE OF AN INNOVATIVE DESIGN

Carlos Lasarte
PEQUIVEN, S.A., Petroquímica de Venezuela
El Tablazo. Apartado 159
Maracaibo, Venezuela

Oladis T. de Rincón and Albenix Montiel
UNIVERSIDAD DEL ZULIA - Centro de Estudios de Corrosión
Apartado 10482
Maracaibo, Venezuela

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Location

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Evaluation - Characterization of the Macro and Micro Environments in each area of the plants to select the best coating options

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials








The test of the various options of coatings in each critical area of the plants, to select the best performance

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

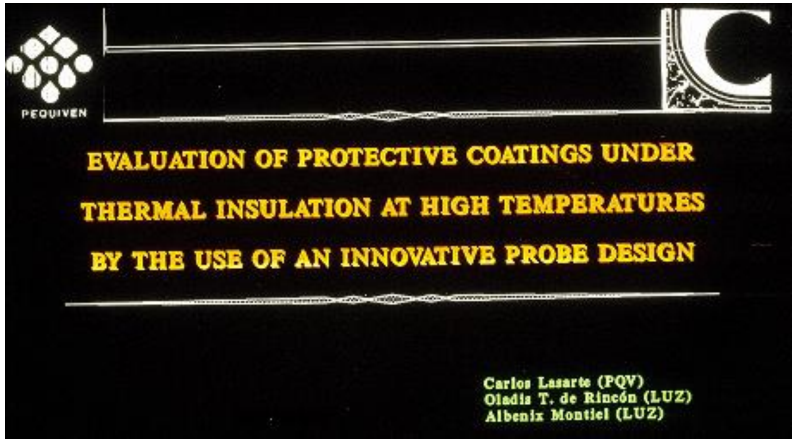
... To achieve the best possible protection, with the best cost-benefit ratio, in each plant area

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials



... But we had neglected the protection of pipes and equipment under thermal insulation.

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

A high percentage of equipment and pipes are thermally insulated.
The Facilities, with more than 35 years usually do not have
Metallic Surface Protective Coatings

For Different Reasons the Vapor Barrier and Waterproofing Covers Fail.

Once the Thermal Insulation System Becomes Permeable to the Humidity of the Environment, the Metallic Surface begins a Wet Corrosion Process, which will basically depend on the Operation-temperatures Cycles and the Pollution Levels of the Environment.

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Typical misuse of thermally insulated equipment and pipes

Carlos Lasarte

Combustión, Energía & Ambiente, s.a.

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

At that time:

References on Corrosion Problems Under Thermal Insulation

Technical Committee Report

NACE International Task Groups

✓ T-6H-31 Coating for Carbon and Stainless Steel Under Insulation

✓ T-5A-30 Corrosion Under Thermal Insulation

Reporte:

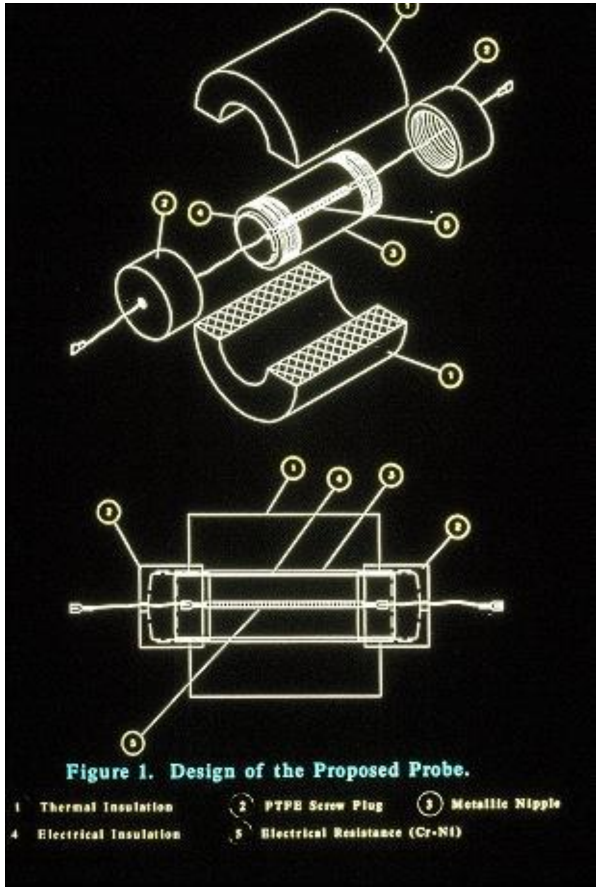
"A State–of–Art Report of Protective Coatings for Carbon Thermal Insulation and Cementitious Fireproofing – última emisión: Marzo 1996"

How to Select the best Protective Coating Option?

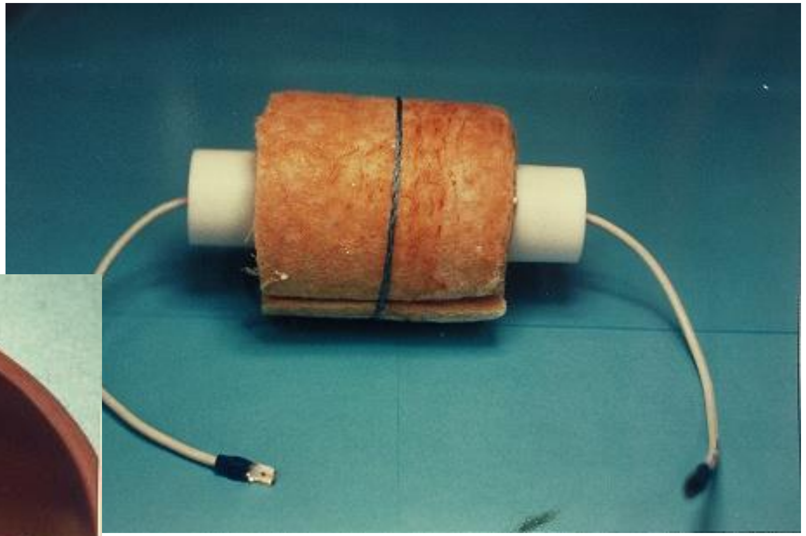
Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

How to Select the best Protective Coating Option?



To evaluate the various options of protective coatings, to be used under thermal insulation, the ASTM standards were searched and since a specific design was not found, a test tube was designed to achieve an evaluation with accelerated results



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Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

EXPOSURE CONDITIONS

Nipples Material: ASTM-53 GrB

Coatings

- ✓ Inorganic Zinc (silicate)
- ✓ Silicone Aluminiun
- ✓ Aluminium Metallized

Surface Preparation: SSPC-SP5

Insulating Materials Used:

- ✓ Fiberglass
- ✓ Mineral Wool
- ✓ Calcium Silicate

“Saline Chamber”	4% p/v
Thermal Cycles	12 hours
Maximum temperature	150 ºC
Minimum temperature	30 ºC

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Al Silicona

Al Metalizado

Zinc Inorgánico

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Probeta	Tiempo de Exposición	Relación Vs. Blanco
Blanco Control	120 horas	……….
Al Silicona	816 horas	6.8
Zinc Inorgánico	1.104 horas	9.2
Al Metalizado	4.800 horas sin ningún daño	> 40

RESULTADOS:

Insulating Coating	Performance
Calcium Silicate	Best
Fiberglass	Intermedium
Mineral Wool	Deteriorated most

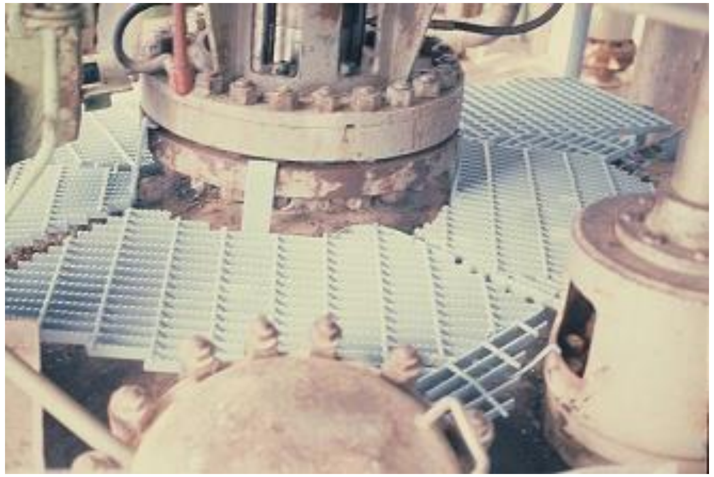
Aluminium-Silicone and Inorganic Zinc failed by blistering first in combination with Mineral Wool

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Almost immediately the results were used in the painting of the heating jacket of a polymerization reactor (Polystyrene), making use of the combination: Inorganic Zinc and Fiberglass, with apparent good results after inspection done two years later.

It was necessary to implement protections against misuse by operators, who had to walk on the insulation to act some valves



The rehabilitation process continued with the insulated pipes, located in areas - very high humidity microenvironments

Carlos Lasarte

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Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

The next protection system to be implemented was the one used in the structures covered with fire protection system

Corrosion Under Insulation (CUI)

thermal insulation and fireproofing materials

Using Chlorinated Rubber paint for direct protection of steel structures and sealing of fire protection cement

Muchas Gracias por su Atención

Carlos Lasarte

Phone-WhatsApp +34-625898225

Skype: carlosluislasartev

carlos.lasarte@ceaca.com

Appendix 6

Overview of the research done recently at TWI

(Che Ming Lee)

TWI

JOINING
INNOVATION
AND EXPERTISE

Update on CUI research at TWI - WP15 Eurocorr 2019

Global Training and Technology Services

1) Risk-based assessment of CUI (Work done with Kaefer)

- Paper in Eurocorr 2019 – 226986 (Watt, Lee, Jopen, Patterson)
  - (WP13, Thurs 12/9/19, 3pm, Room Sevilla 3+4)

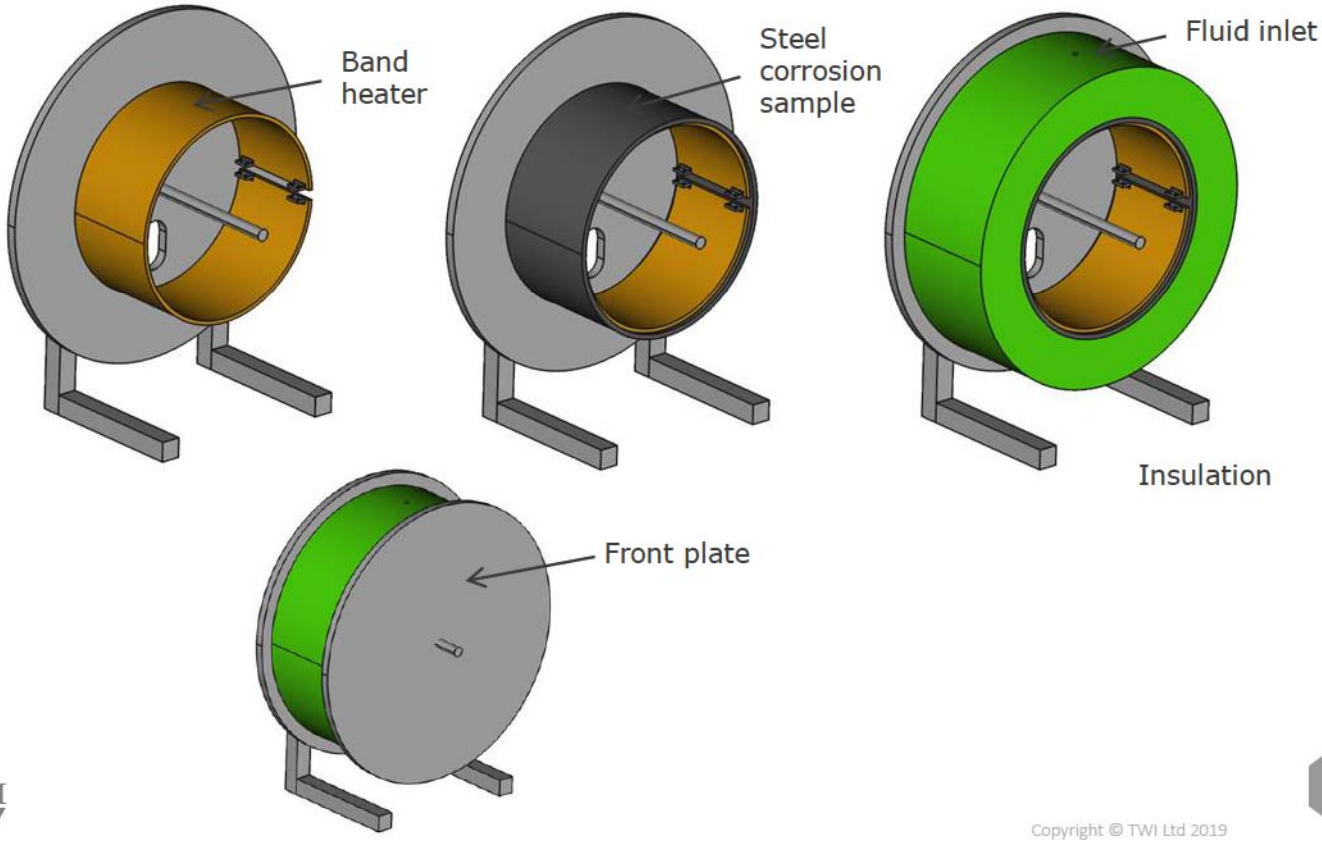
- Review of CUI RBI methodologies
- Review of literature on plant CUI data
- Compare with case study using actual historical plant data

- Public guidance/standards (API, NACE, EFC)
- 8 in-house methods (dating from 2006-2017)
- Historic gas plant CUI inspection data

2) CUI TSA testing project

- Extensive testing programme to investigate the behaviour of TSA in solutions containing leachants from insulation material.
- A range of insulation materials were investigated
- Plus the effects sealant and of paint overlap
- DI water and artificial seawater

3) Development of CUI simulation test rig



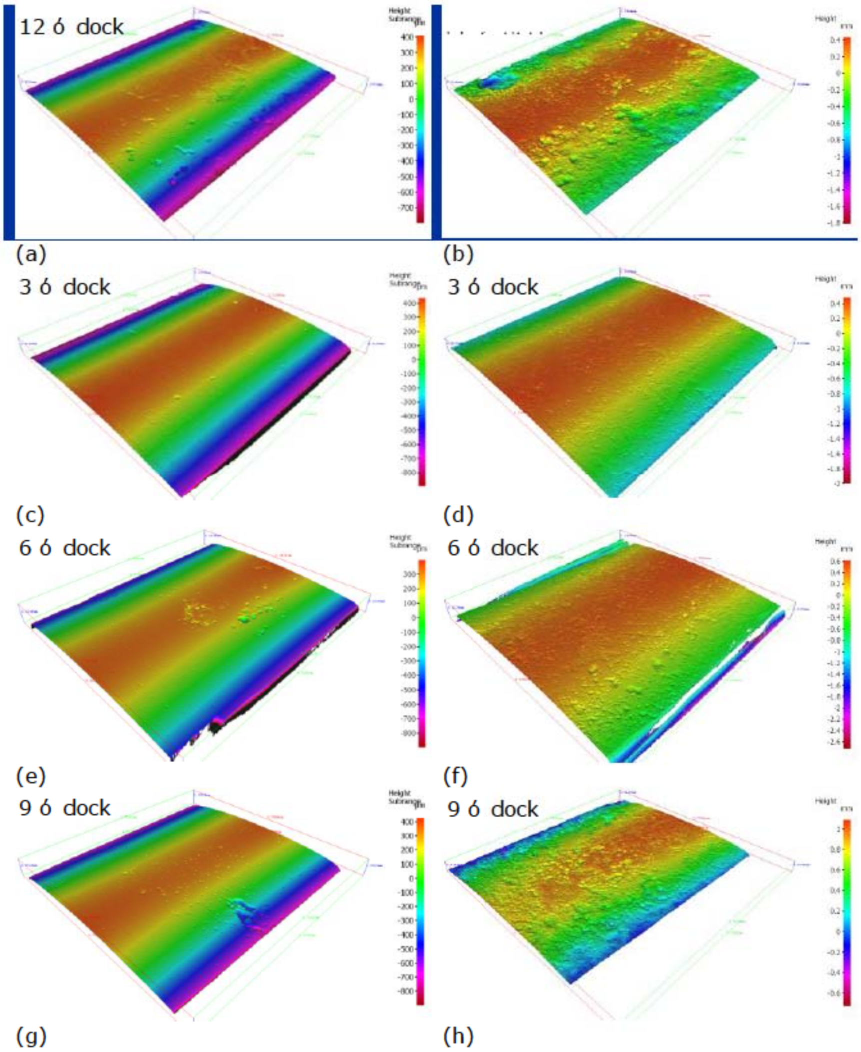
Uncoated pipe, 30 days, ~80ºC, 0.1wt% NaCl

Glass Foam

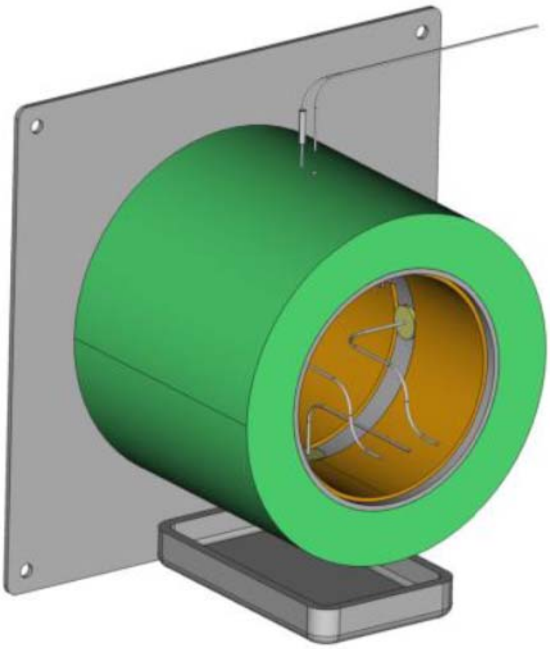
Mineral Fibre

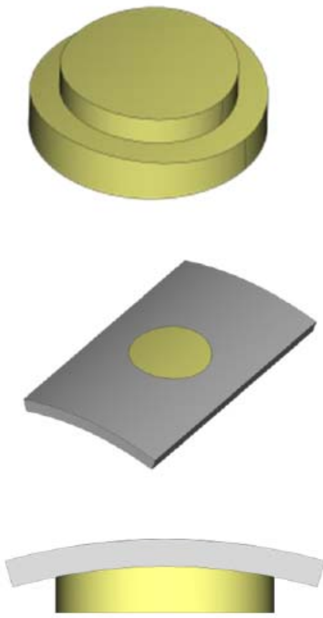
Max pit depth ~0.7mm

TWI


12 ó dock
(a)
(b)
3 ó dock
(c)
3 ó dock
(d)
6 ó dock
(e)
6 ó dock
(f)
9 ó dock
(g)
9 ó dock
(h)

With Sensors

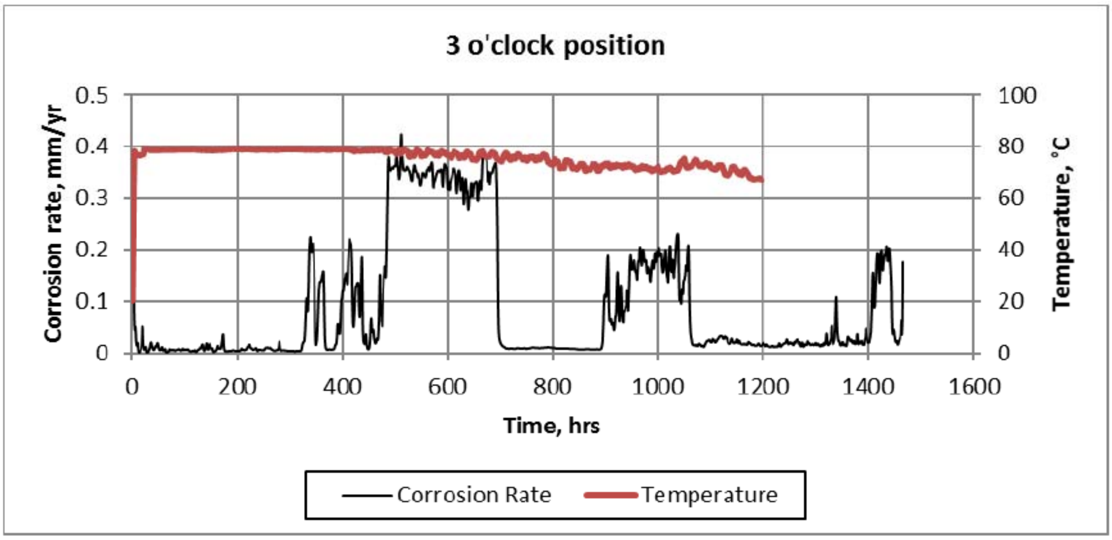




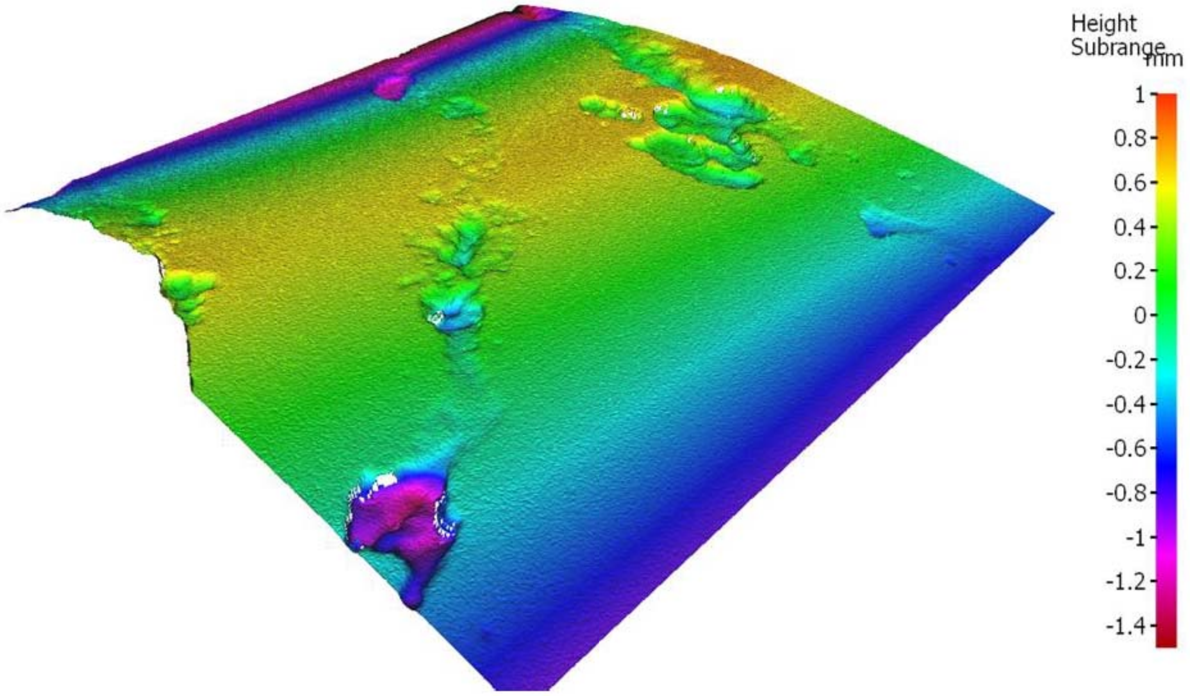
TWI

Uncoated pipe, Mineral Fibre, 60 days, 80ºC

Example of Sensor Data



Max depth ~1.19mm



TWI

Future Plans at TWI for CUI

- Propose new JIP to include:
  - Developing an improved RBI methodology for CUI
  - Further testing of TSA and other coatings in simulated CUI test rig
  - Generate baseline CR vs Temp data for model
  - Collate and review any new CUI plant data
- Continue research on effective NDT for CUI (Projects + PhDs)
- Engage with API 581 committee on development of CUI RBI model

Appendix 7

CorrosionRADAR CUI monitoring and prediction system - Recent case studies

(Prafull Sharma)

corrosion RADAR

CUI Monitoring System and Predictive Corrosion Management: Case Studies

www.corrosionradar.com

A Cranfield University Spinout

EUROPEAN FEDERATION OF CORROSION

EFC Work Party 15
Annual Meeting
September 11th 2019
Seville, Spain

Inspection 4.0

A New era of Asset integrity

Inspection 1.0
Manual observation, Leaks

Inspection 2.0
Visualisation, NDT instruments

Inspection 3.0
Statistics, RBI

Inspection 4.0
Automated, Analytics, Prediction

Manual → Automated

Detection → Prediction

Reaction → Prevention

Problem

Hidden Corrosion

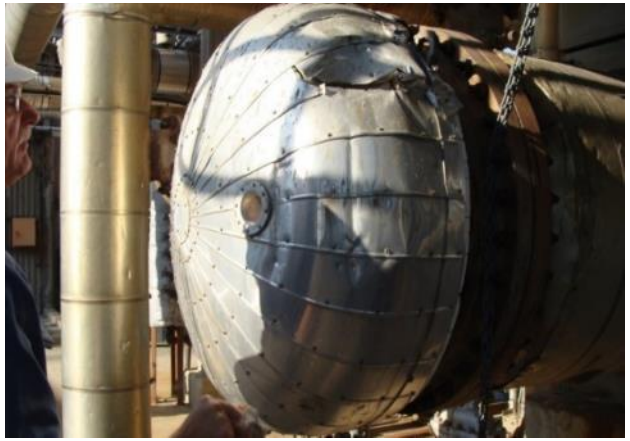
Oil & Gas

Chemical Industry

Renewable Energy

Civil & Construction

Corrosion Under Insulation (CUI)



Imagine an ideal world with no CUI

Prevention

(Coatings, Insulations, Metallurgy..)

Monitoring

(NDT, Sensors, Data)

Solution

The Current Practice

WHERE?

WHEN?

CURRENT PRACTICE

Human judgement + guessed risk ↔ Periodic Manual Inspection → { WHERE / WHEN } →

Reactive Maintenance

- Labour Intensive
- Unscheduled Shutdowns
- Safety Risk
- High cost

Cost of CUI in Oil and Gas → **> £3.5B** Annual spent on CUI

IDEAL PRACTICE

Automated risk profiling → Continuous Monitoring → { WHERE / WHEN } →

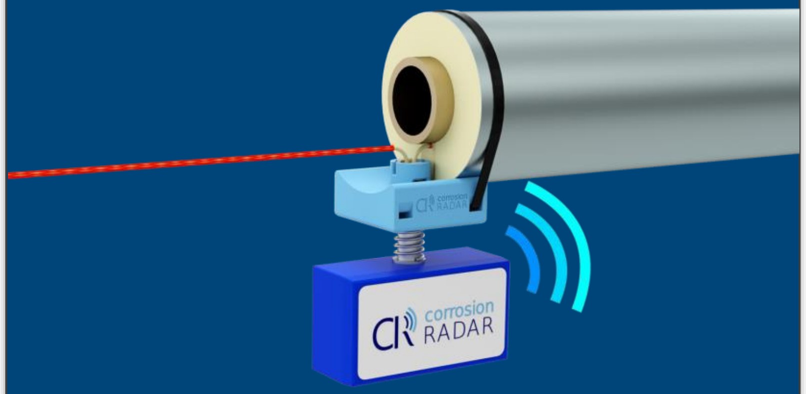
Predictive Maintenance

- Minimal labour effort
- Scheduling Maintenance
- Improve safety
- Reduce cost

Solution

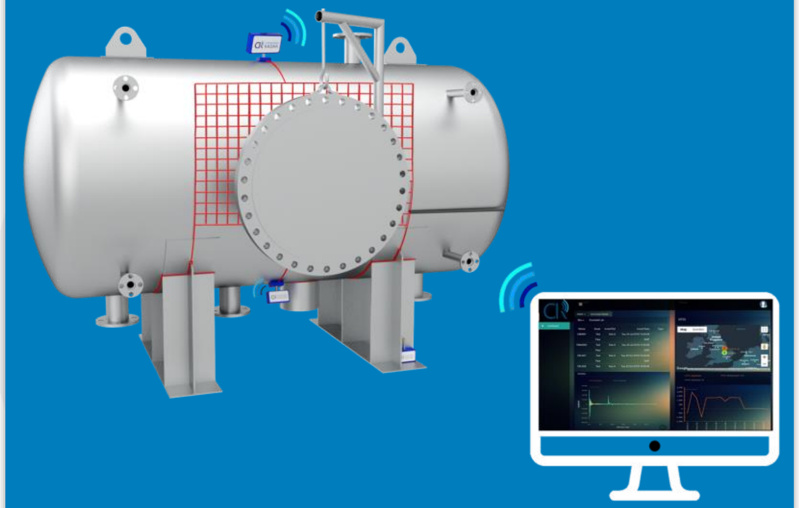
CorrosionRADAR Technology

DETECT



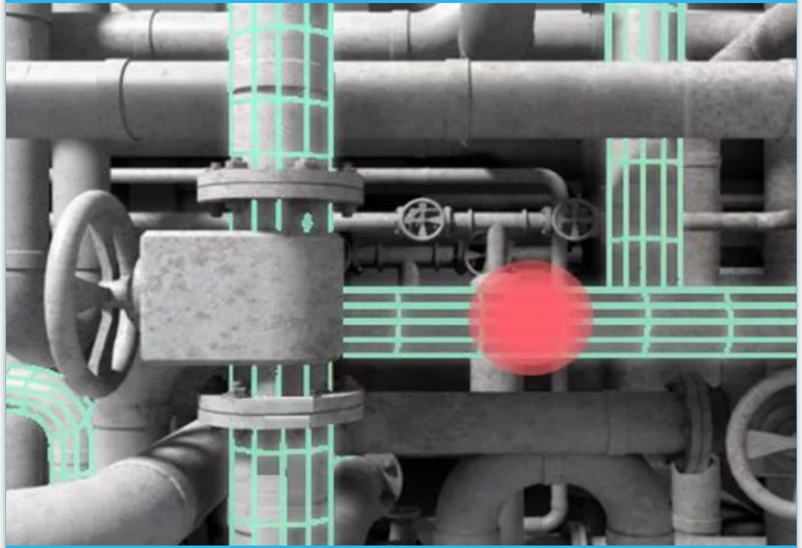
- Distributed Corrosion & Moisture Sensors
- Long Range Coverage
- Cost Effective Installation
- Covering Complex Pipe works

CONNECT



- Long-Life Battery Powered
- Remote Wireless Communications
- Continuous Monitoring
- Dashboard for Actionable Intelligence

PREDICT

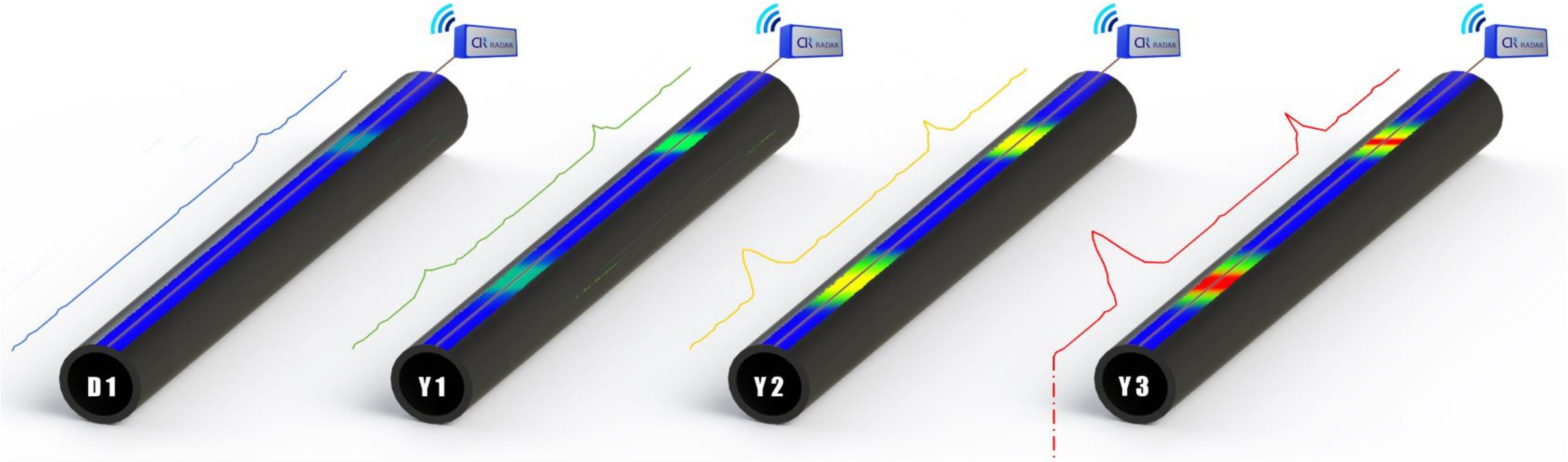


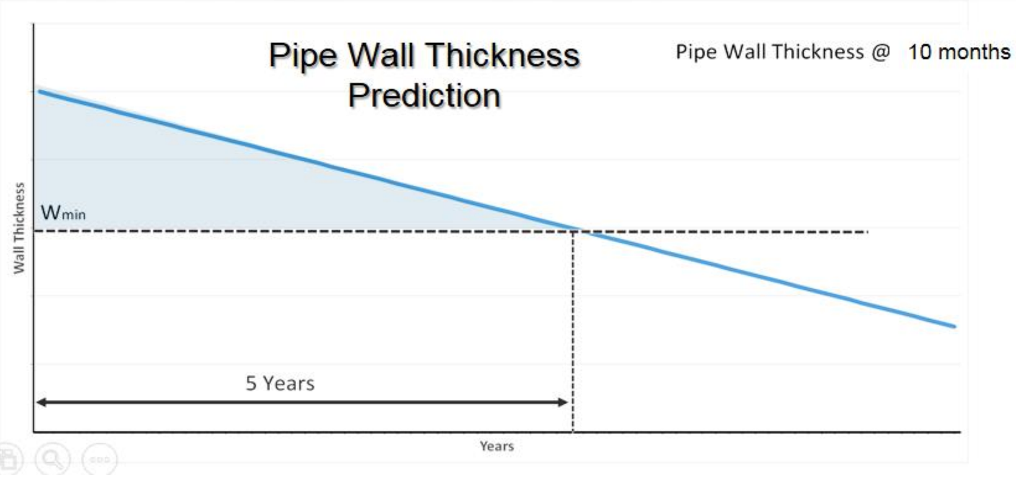
- Predictive Asset Management
- Asset life extension
- Effective Risk Management
- Historical Data & Analytics

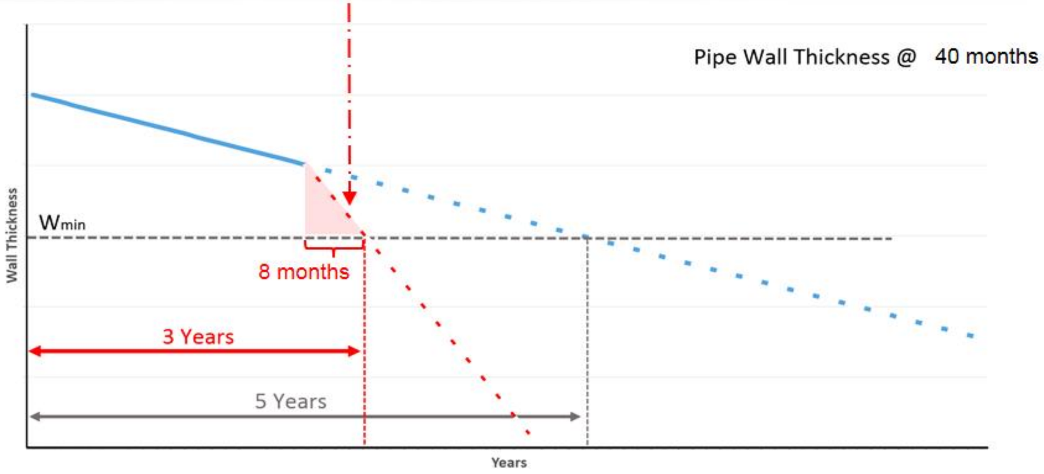
Principle

Electromagnetic Guided Wave Radar

Wave reflection time-of-flight locates the corrosion on sensor







CorrosionRADAR System

SPECIFICATIONS - SENSORS

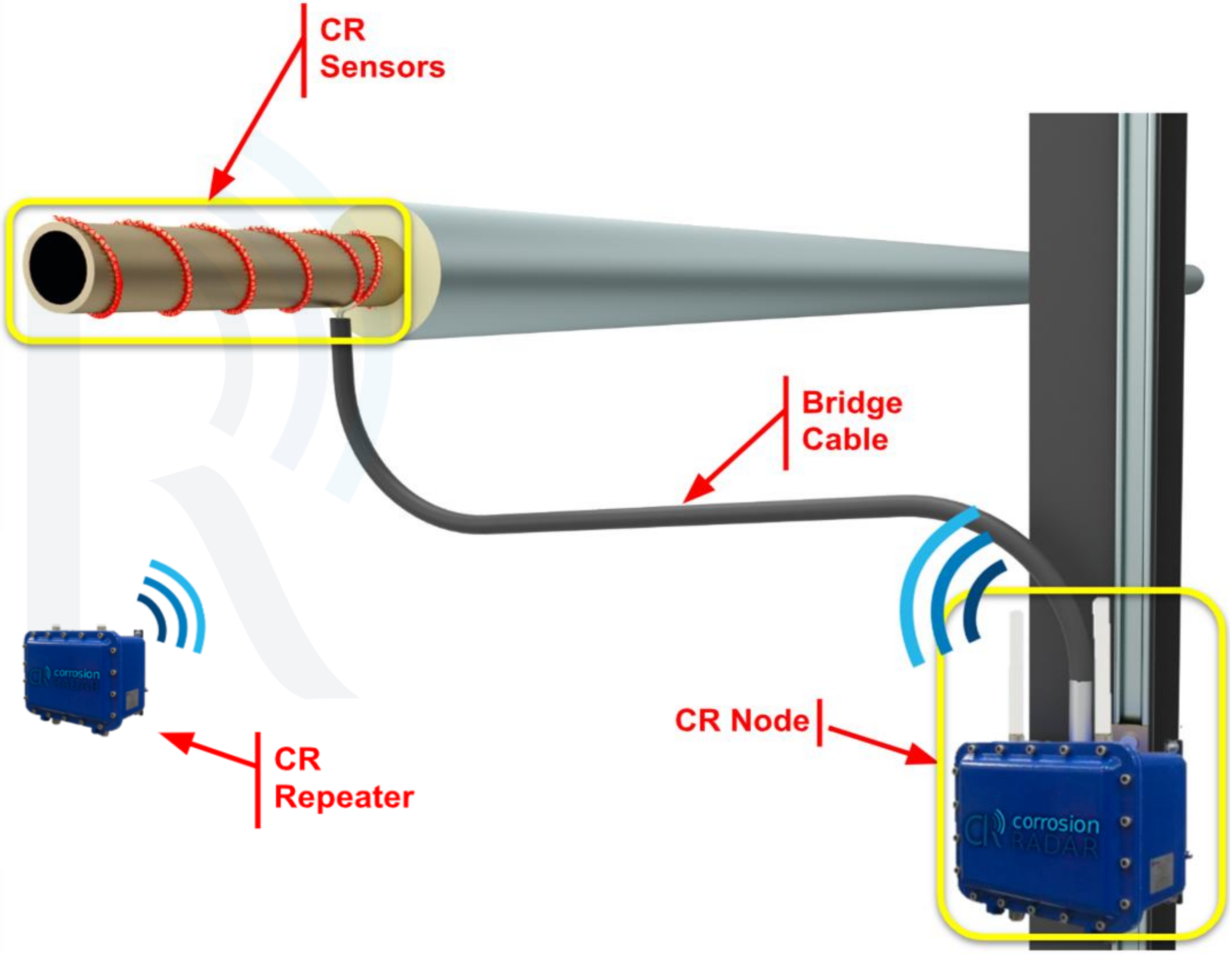
Technology Fundamental:

The CorrosionRADAR (CR) technology is based on Guided-wave Electromagnetic principle and embedded sensors inside the insulation. CR sensors are designed in such a way to carry an electromagnetic wave unaffected by the field complexities (flanges, bends, pipe support, …).
Thanks to the sacrificial layer of the sensors, the locations prone to corrosion activity can be pinpointed as the sensor reacts to a potential corrosive environment surrounding the monitored asset. The sacrificial layer of the sensors can be made out of various different materials and close to the material of the asset.
The data obtained from CR sensors can be used as a "Risk Profiling Tool" to enhance and optimise the RBI maintenance programs.

Material of CR Sensors

Most commonly used sensors are made out of carbon steel, however, other sensor materials are also available. Moreover, in the case of difference between CR sensor material to the asset's material, corrosion correlation approach can be used.

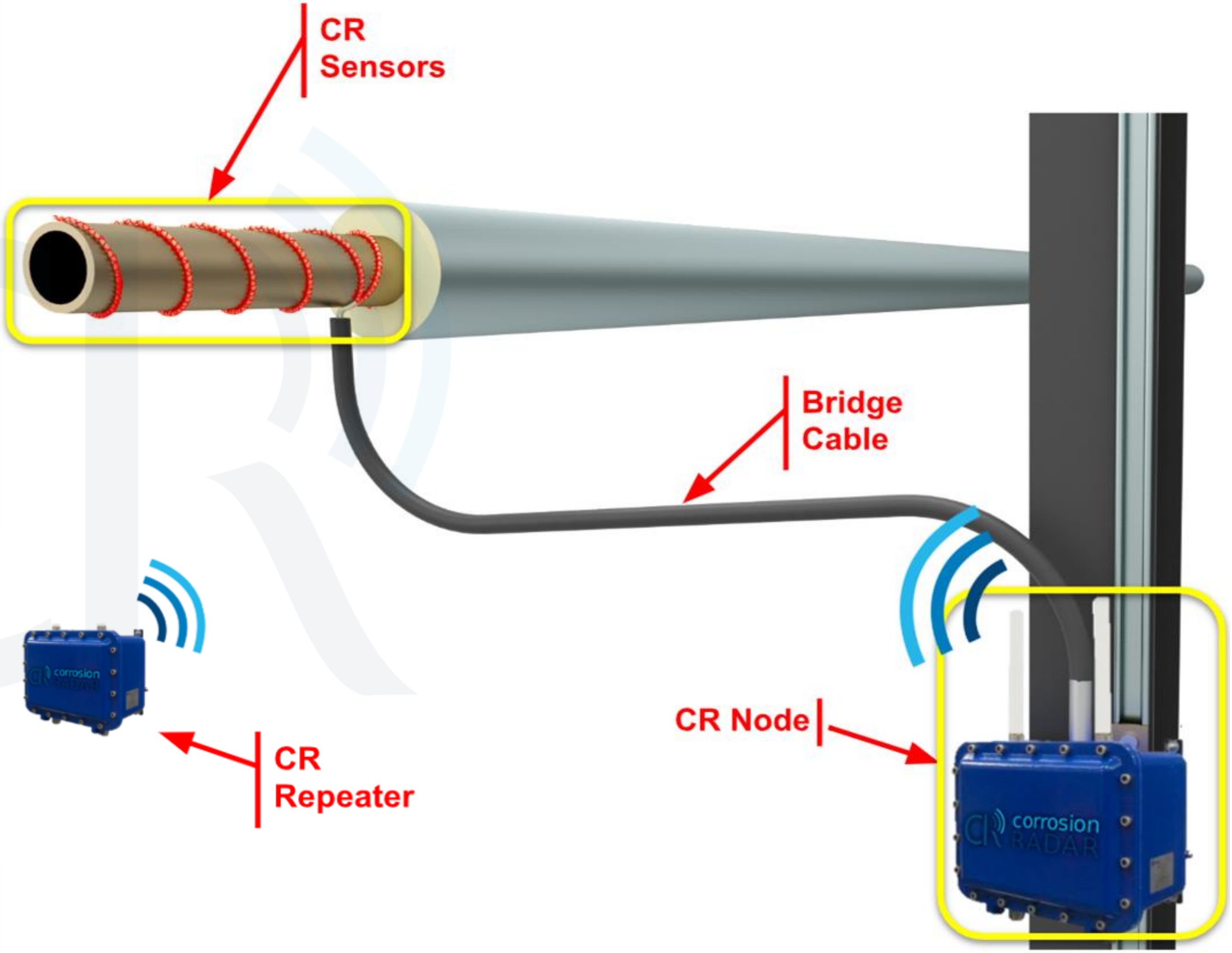
Sensors Type	**Corrosion Sensor**	**Moisture Sensor**
Sensor Length	Up to 100m	Up to 50m
Temperature Range	-50 to +300 ^{0}C	-50 to +200 ^{0}C



CorrosionRADAR System

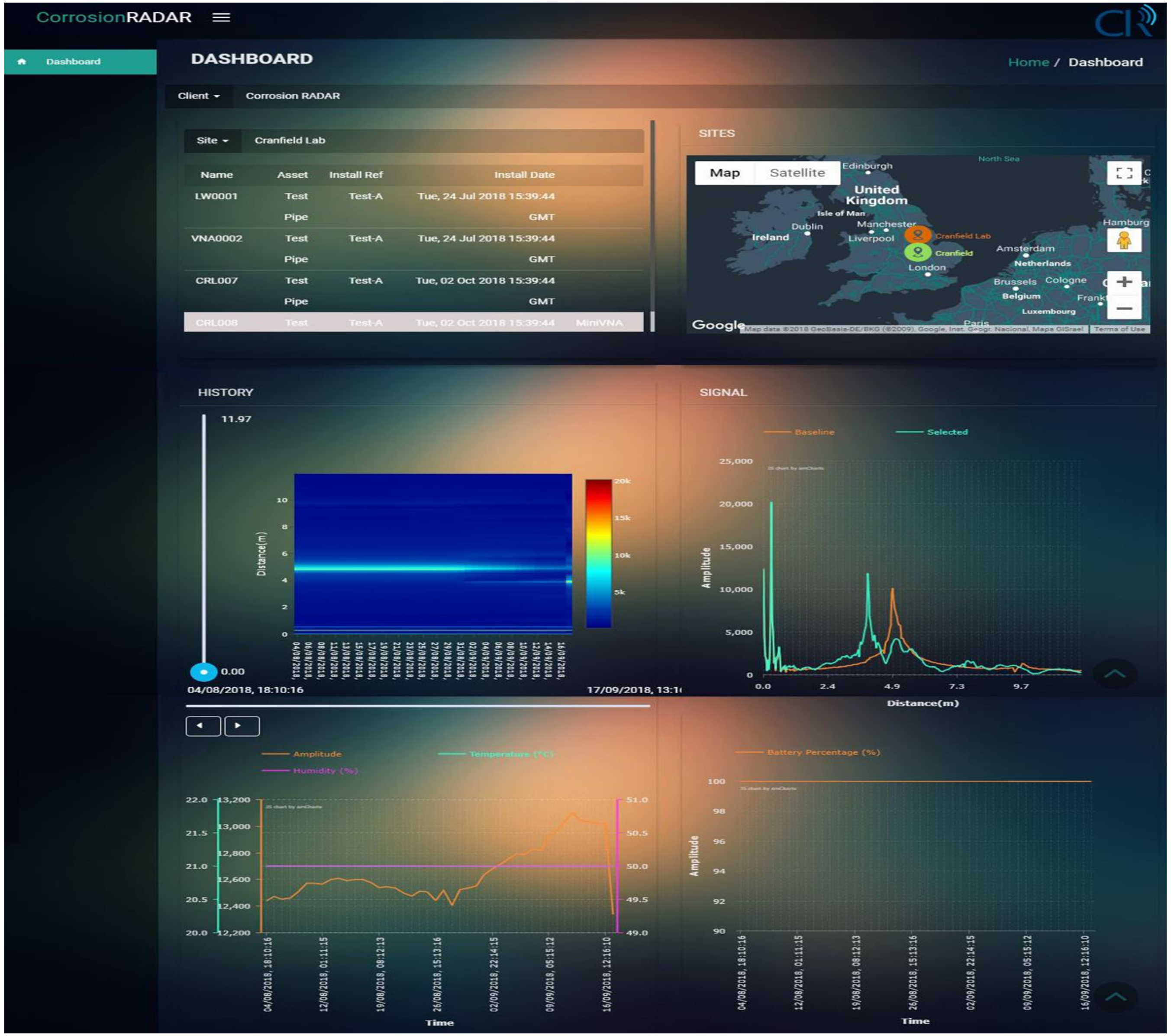
SPECIFICATIONS - ELECTRONICS

Dimensions (mm) excl. antenna	284x245x169	**Mass (kg)**	11.2 Kg
Ports	1x power cable 2x SMA	**Power requirements**	220V AC
ATEX certification	EXd Zone1 Group2	**IP rating**	IP66
Connectivity/ Data transfer	Cellular, Wi-Fi, WirelessHART, LoRa	**Ambient temperature range (°C)**	-20 to +60



CorrosionRADAR System

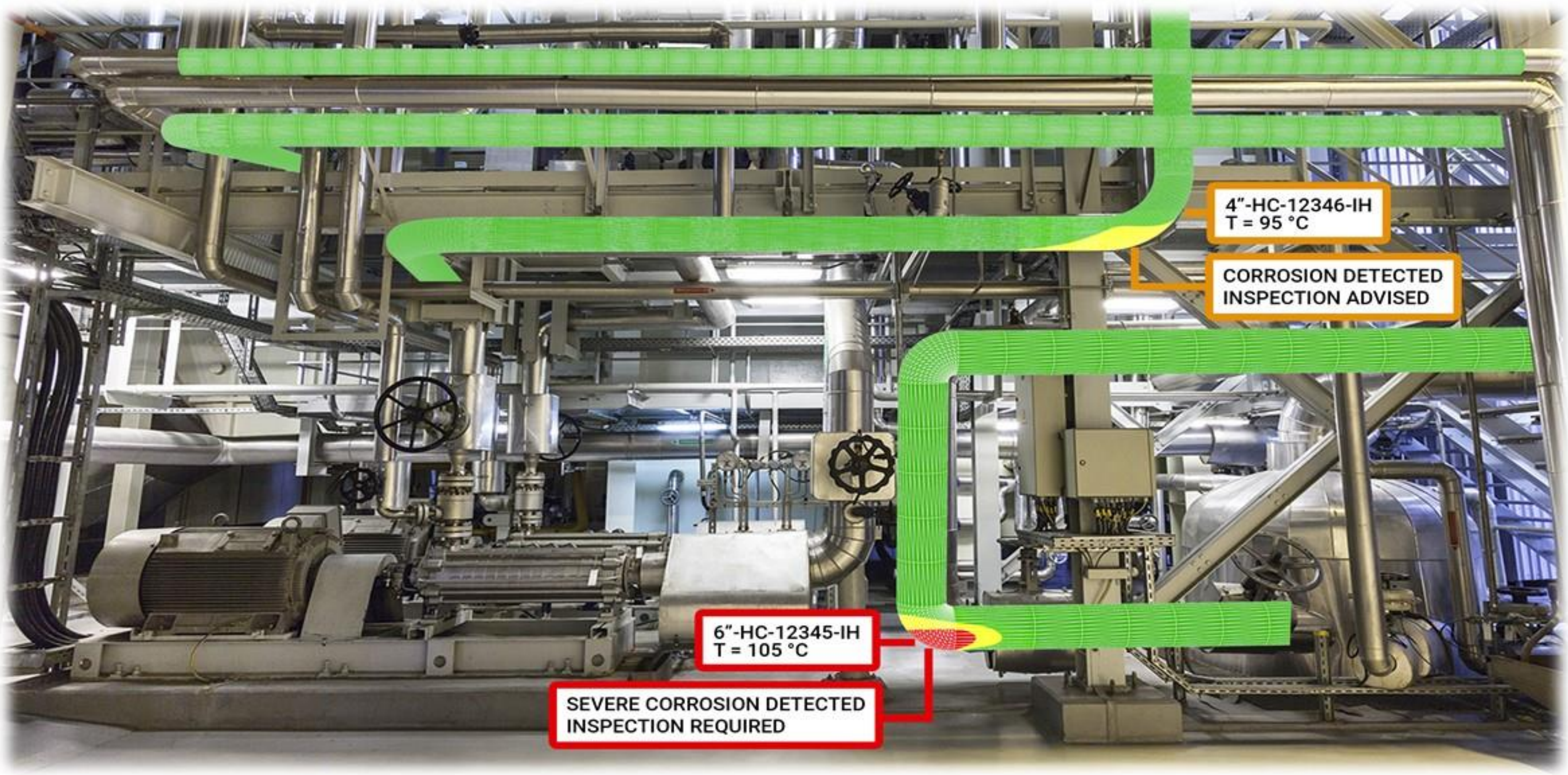
Specifications – Online Dashboard



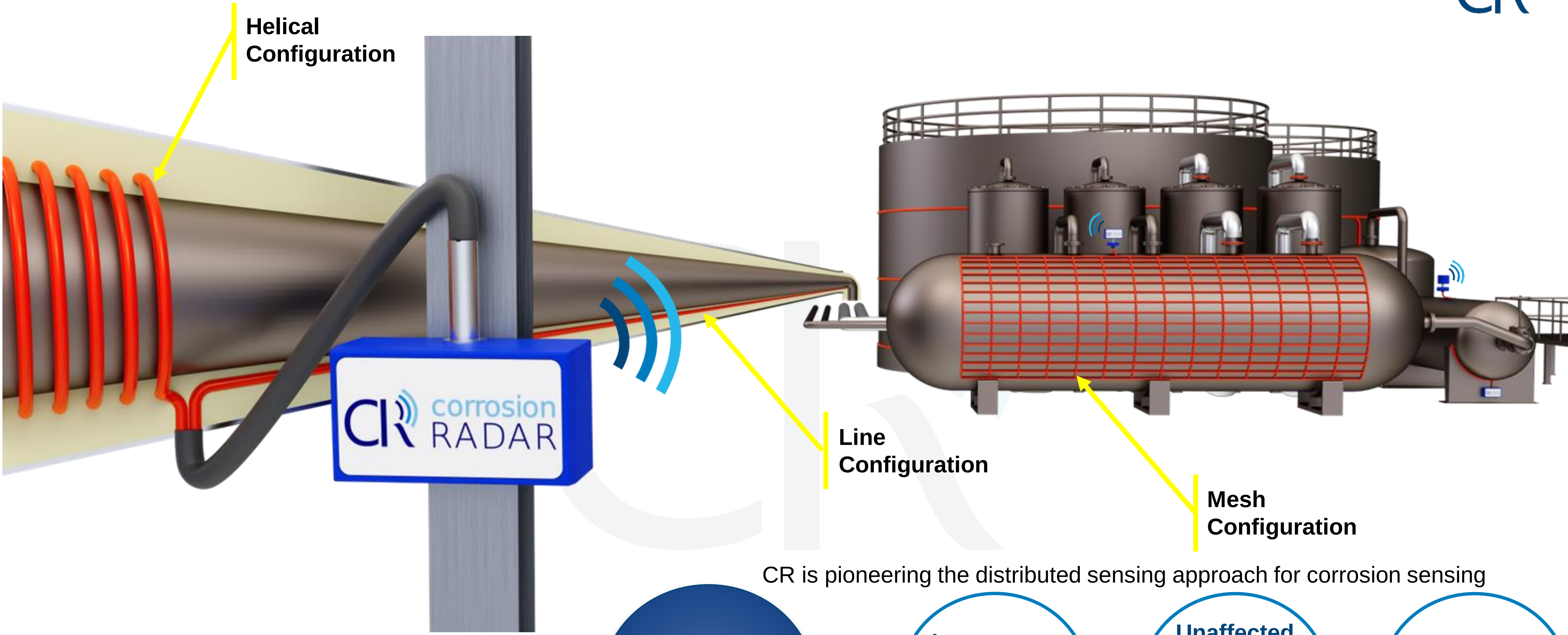
Towards Asset Digitalisation

DIGITAL TWIN OF ASSET INTEGRITY

100% Pipe length coverage for assets digitalisation and enabling digital twins



CR Use Cases



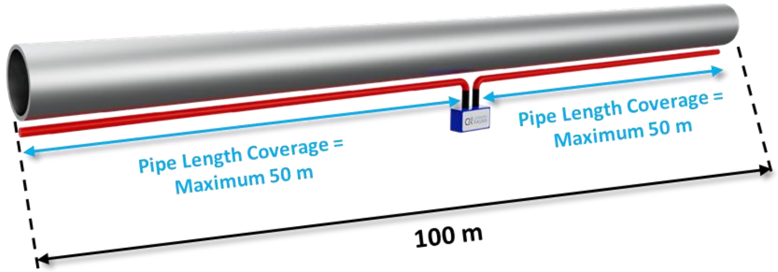
CR is pioneering the distributed sensing approach for corrosion sensing

Embedded Sensors = **Long-range & Modular** (each sensor unit can cover up to 1 km) + **Unaffected by Complex Geometries** (e.g. vessels, pipe bends, flanges...) + **Cost Effective for Mass Deployment**

Installation Configurations

Sensor Length = 50 m (max per channel)

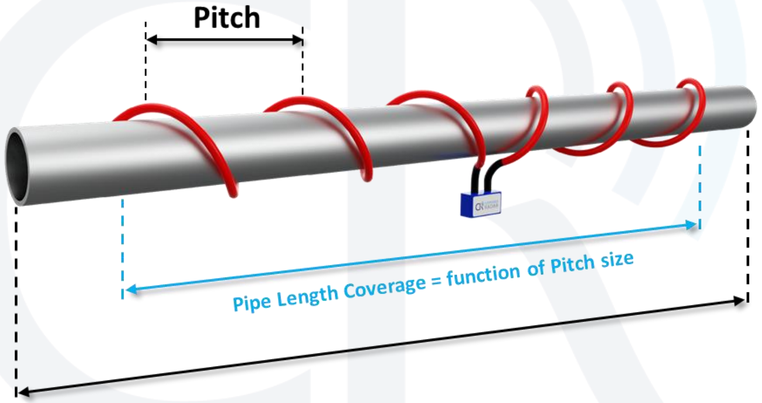
Pipe Length Coverage = 100 m



Bi-directional configuration-> More pipe **length** coverage

Sensor Length = 50 m (max per channel)

Pipe Length Coverage = function of Pitch size



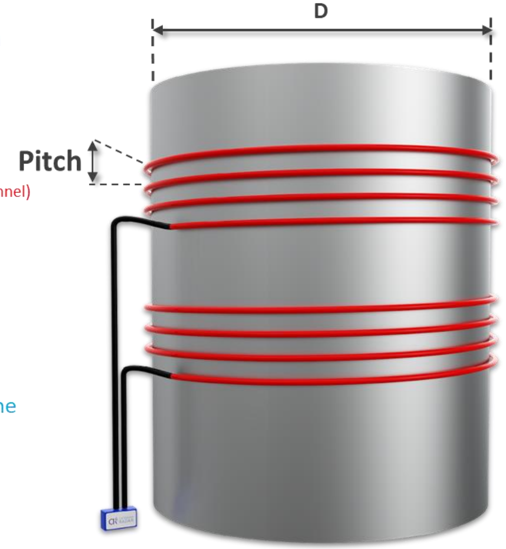
Helical Configuration

Sensor Length =

Up to 50 m (50 m max per channel)

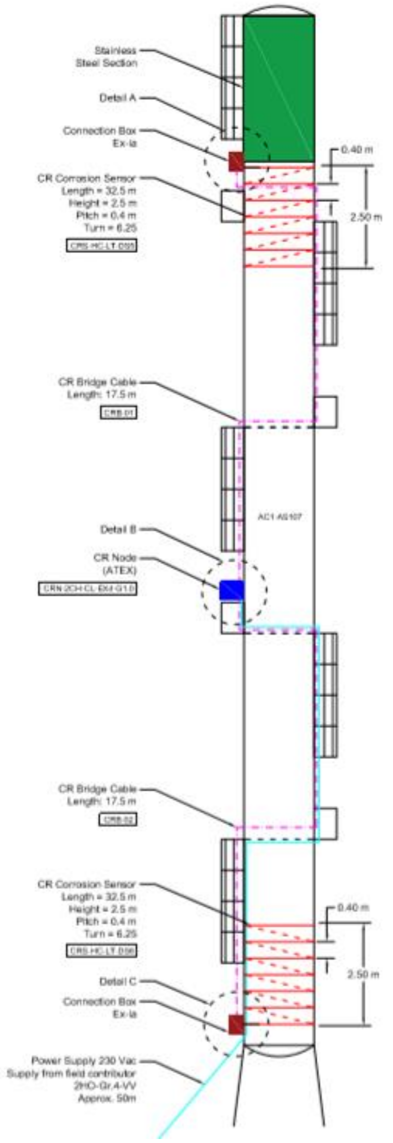
Vessel Area Coverage =

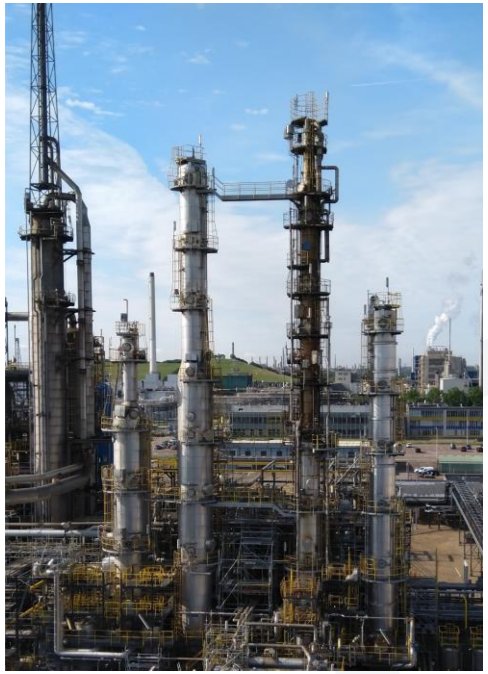
Covering large **surface** of the vessel at fixed heights as a function of Pitch size



Case Study A

PRODUCTION COLUMN CORROSION MONITORING (ATEX)





Case Study A

CUSTOMER'S FEEDBACK

Chemelot

sitech services

home about us how we work

Columbus's egg for corrosion under insulation?

Published: 17-07-2019

Corrosion under insulation (CUI) is a serious threat to the safe operation of chemical installations. Tackling this leads to huge maintenance costs for the process industry. That is why Sitech Services uses innovative techniques to make corrosion under insulation predictable.

Monitoring moisture and corrosion

"We are currently implementing an innovative technique developed by the UK company CorriosionRADAR," says Peter Janssen (Senior Mechanical Engineer Corrosion & Materials at Sitech Services). "The measuring device consists of a carbon-steel wire that contains integrated sensors. We apply them to the high-risk sections of an installation, like a column or pipe. Once the system is operational, a radar signal is sent through the wire, which can be used to identify the presence of corrosion. The data are read by means of a wireless network and can be monitored continuously. This is currently still being done by CorrosionRADAR itself, but we are busy transferring it to our Sitech Asset Health Center. This application is being tested with an ATEX-certified system, the first of its kind in the world."

Sitech invests in innovation

The new technique is applied in the AnQore ACN plants, more specifically in the AS107 column, which is sensitive to corrosion under insulation. Peter: "Early this year we heard that the insulation of the AS107 column would be removed during the turnaround for it to be blasted and preserved. It was a unique opportunity to test this technique in a plant environment, as this only happens every 15 to 20 years. We entered into discussions with the Plant Manager and were even prepared to pay for the investment ourselves, as innovation is so important to Sitech. Thanks to the efforts from the workers at AnQore and the turnaround team, this project was successfully carried out during the turnaround."

"Innovations and an integrated approach allow us to reduce maintenance costs by predicting corrosion under insulation and ultimately preventing it."

Peter Janssen, Senior Mechanical Engineer Corrosion & Materials at Sitech Services

Significant savings on maintenance

What are the benefits? Steven Custers (Materials & Corrosion Engineer at Sitech): "We expect that we will not to have to unpack the column for the next 25 years, as we are now capable of measuring whether any moisture enters the insulation and corrosion occurs, the extent to which it occurs and where it is located. We can determine this with an accuracy of about 10 centimeters. If repairs are required, the insulation will only need to be locally removed in the spot where the repair work is required. Normally speaking you would have to unpack the entire installation, even if you only have 5% damage. That leads to significant costs, including costs for erecting scaffolding, wrapping the installation in sheeting and safety measures. You can save on these costs by using this technique, which also makes the installation a lot safer."

Limiting and ultimately preventing CUI The technique developed by CorrosionRADAR is not the only one being tested by the specialized corrosion under insulation project team at Sitech Services. Peter: "Apart from visual inspections, we are constantly investigating and testing innovative, non-destructive methods. But we are always looking for the latest developments in the field of insulation, preservation and coating as well, to limit and ultimately prevent corrosion under insulation."

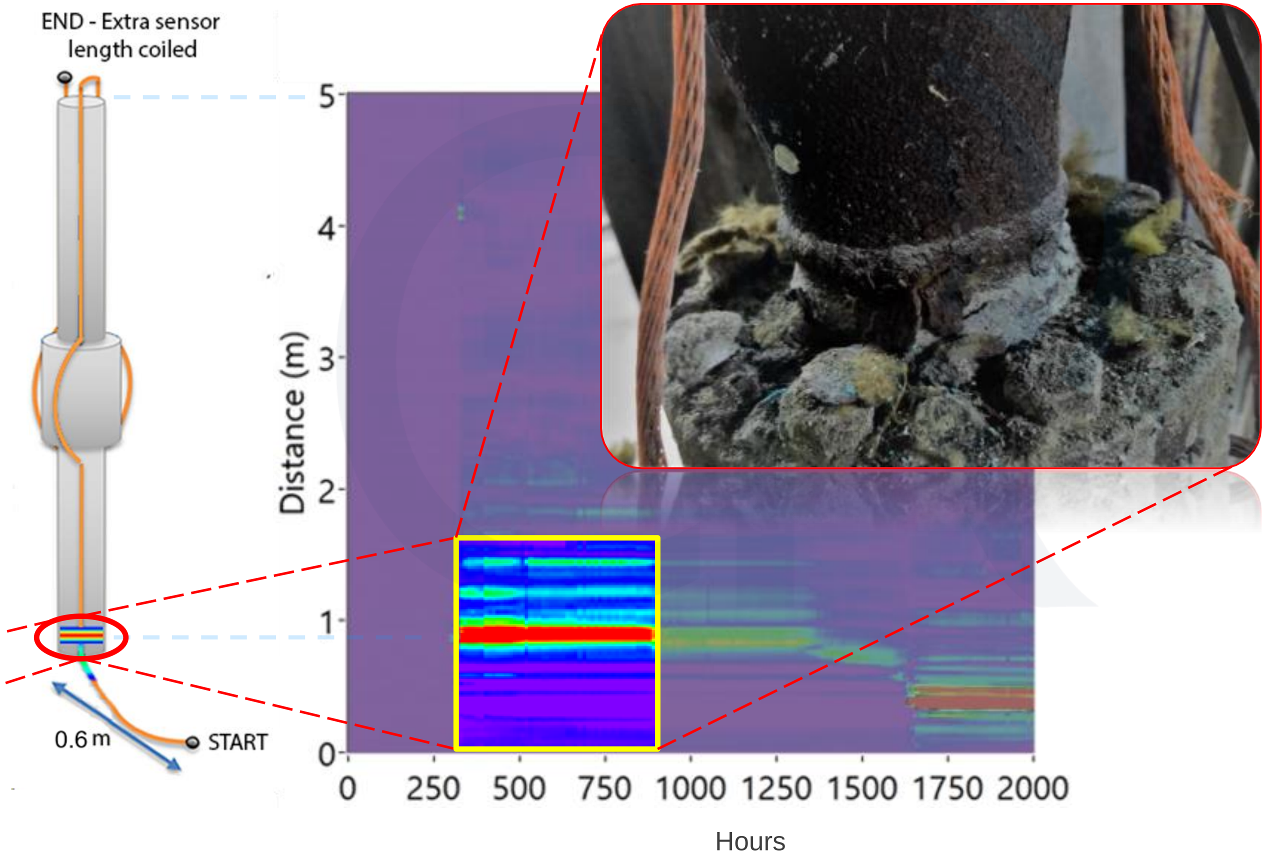
Source: https://www.sitech.nl/tech-update/columbus-egg-for-corrosion-under-insulation

Case Study B

Corrosion Detection

In a six month trial in a chemical plant in EU, CR system has successfully detected, located and continuously monitored a corrosion activity on a pipe, manholes and a vessel

CRL002 – Vertical Pipeline



Example of identified location by CR system where visual inspection confirmed the presence of corrosion on the asset and the CR Sensor. Having the ability to continuously monitor corrosion activity and having access to the data remotely can enhance and reduce maintenance budgets by conducting targeted inspections.

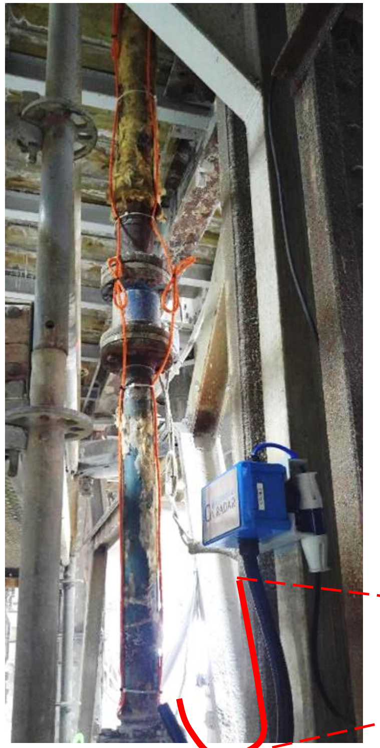
Benefits

- ✔ Confidence in the ability of CR Sensors to react to a corrosive environment.
- ✔ Confidence in the ability of CR Systems to accurately locate corrosive environments.

Case Study B

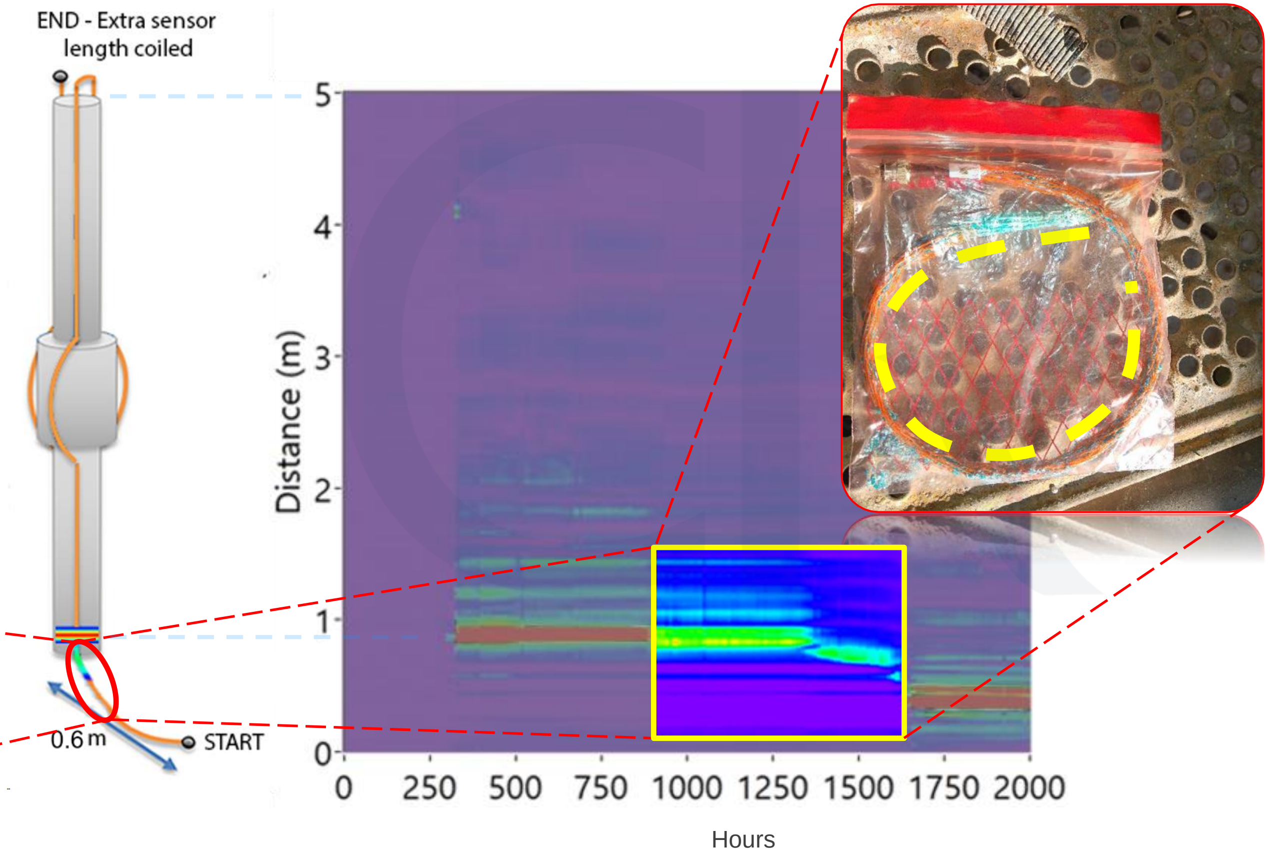
CORROSION PROGRESSION MONITORING

In a six month trial in a chemical plant in EU, CR system has successfully detected, located and continuously monitored a corrosion activity on a pipe, manholes and a vessel



CRL002 – Vertical Pipeline

Propagation of Corrosion



Example of progression of corrosion along the CR sensor length. Visual inspection confirmed the analysis and showed the progression of corrosion on the CR Sensor.

The ability to not only detect and locate but also continuously monitor the progression of corrosion can provide valuable information and assist decision making processes of maintenance team on the ground and increase the safety of the assets.

Benefits

- ✔ Continuously monitoring the progression of the corrosion.
- ✔ Increasing the safety of assets by avoiding loss of containment events.

Case Study C

MOISTURE MONITORING SYSTEM

Figure (A)

Installation of CR corrosion sensors on a 3 inch pipe using cable ties

Figure (B)

Installation of the pre-fabricated insulation around the pipe and the corrosion sensor

Figure (C)

Installed CR Nodes (electronic) driving CR Moisture and Corrosion sensors

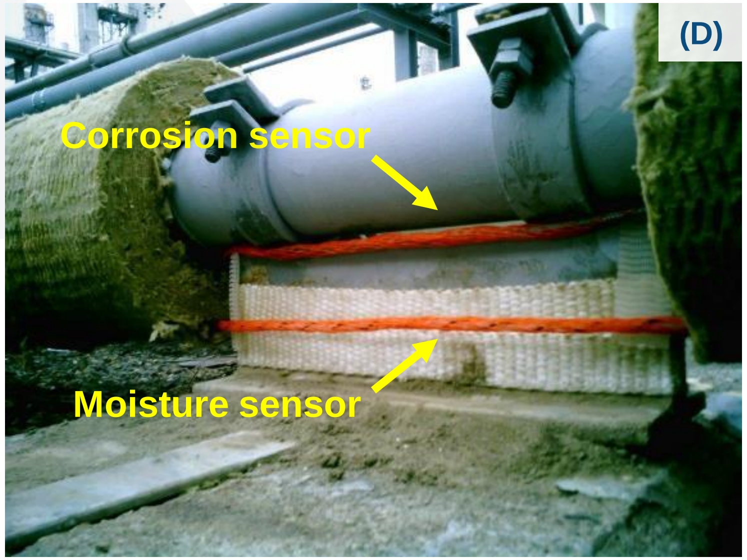


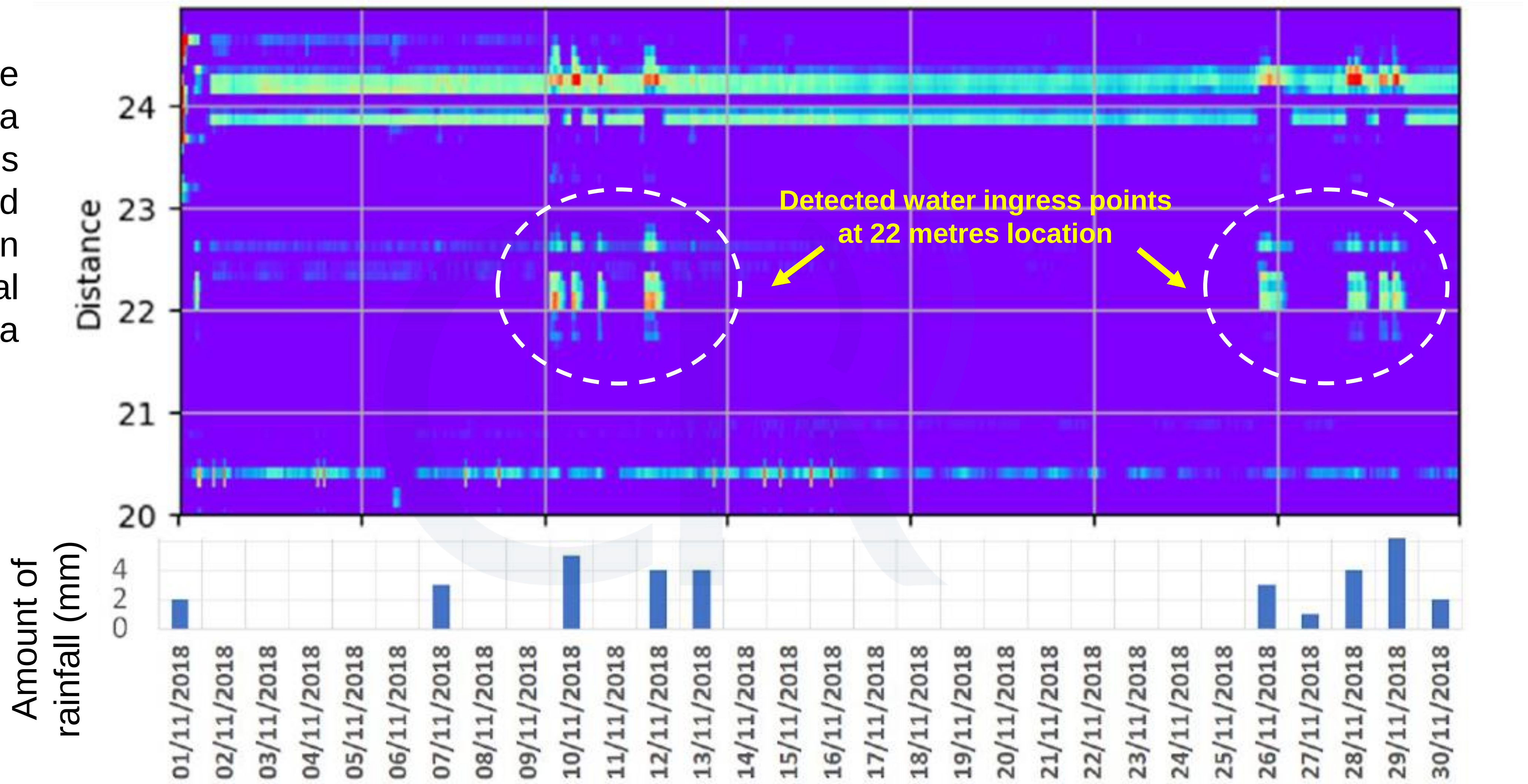
Figure (D)

Moisture sensor is placed inside the pre-fabricated insulations and installed at a fixed distance from the pipe

Case Study C

Moisture Monitoring System

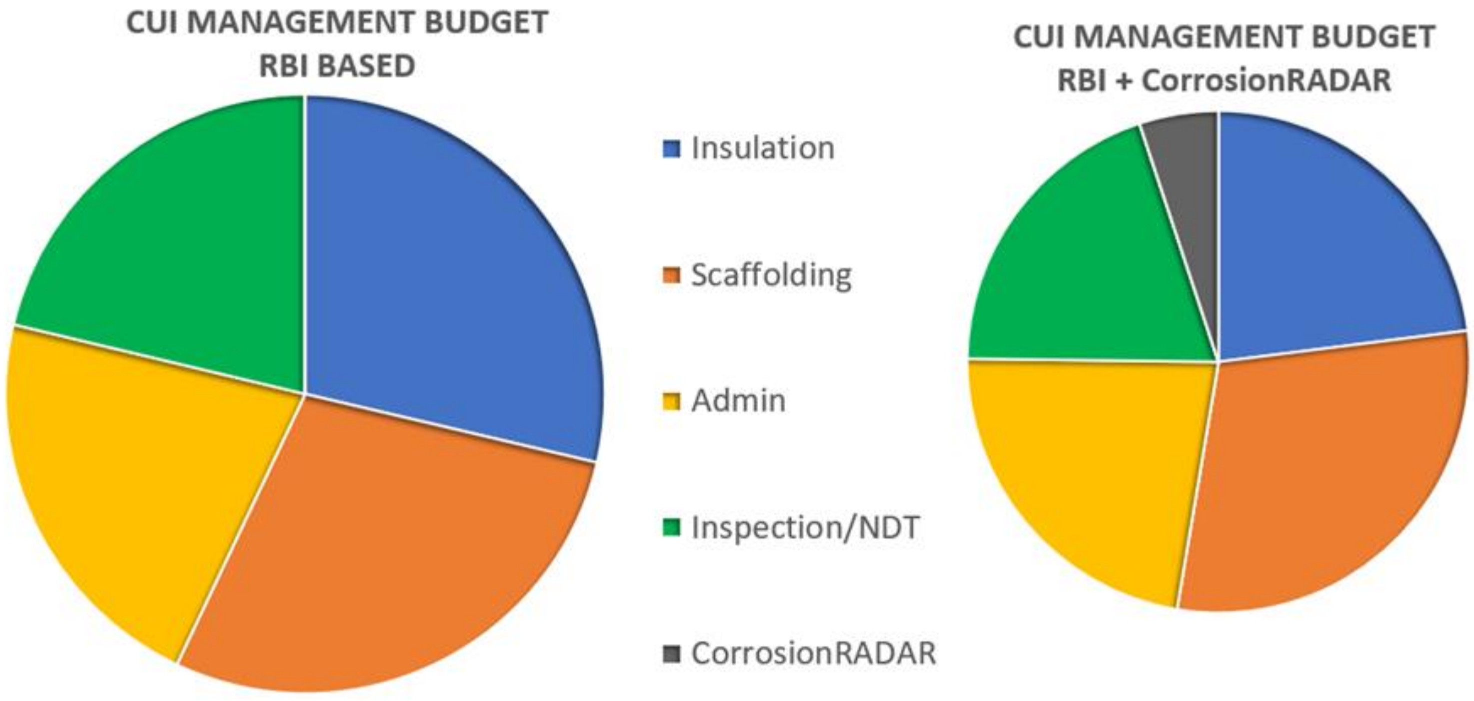
Moisture sensor data analysis and correlation with historical weather data



Data Driven RBI

Benefits to RBI Methodology

Saving CUI management cost by at least 30%
£0.5m to £1m per year per refinery.



£2.8m **Annual Budget** **£2.0m**

Summary

CorrosionRADAR System

- CorrosionRADAR embedded sensor technology
- Monitoring for early detection of corrosion under insulation
- Insulation Moisture monitoring for prediction and prevention of CUI

Detect early

corrosion RADAR

Enabling Smarter Assets

CorrosionRADAR Ltd

Future Business Centre

King’s Hedges Road

Cambridge, CB4 2HY

info@corrosionradar.com

www.corrosionradar.com

Appendix 8

Technical economic feasibility study for the adoption of Thor™115 pipes in Refinery Furnaces

(Luna Fullin, Erick Escorza)

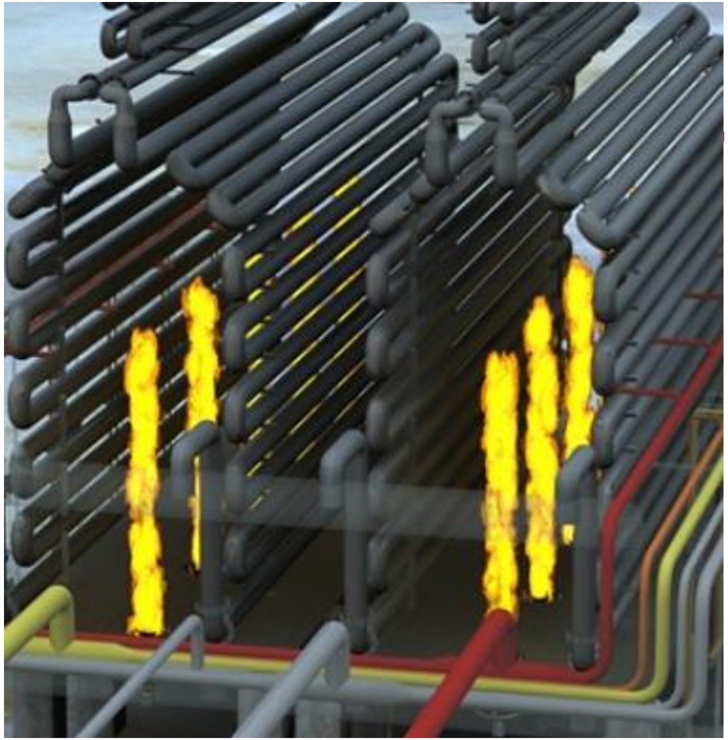
EFC WP15 Corrosion Refinery Industry

Sevilla – September 11th, 2019

Thor™ 115 Pipes in Refinery Furnaces

L. Fullin – Product Engineer

E. Escorza – Product Senior Director



Tenaris

Agenda

- ✓ Introduction of Fired Heater Furnaces and Damage Mechanisms
- ✓ Metallurgy and Properties of Thor™115 and P9
- ✓ Life Model Development:
  - Mechanical Data
  - Creep Data
  - Corrosion Data
- ✓ Model Layout and Validation with Real Cases
- ✓ Economic Evaluation and Benchmark Between Thor™115 and P9
- ✓ Conclusions

Tenaris

Agenda

- ✓ **Introduction of Fired Heater Furnaces and Damage Mechanisms**
- ✓ Metallurgy and Properties of Thor™115 and P9
- ✓ Life Model Development:
  - Mechanical Data
  - Creep Data
  - Corrosion Data
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Fired Heater Furnaces - Design

- ✓ P5 and P9 steel grades typically
- ✓ Process conditions:
  - Up to **600° C** → **creep regime**
  - Low pressures, up to 35 bar

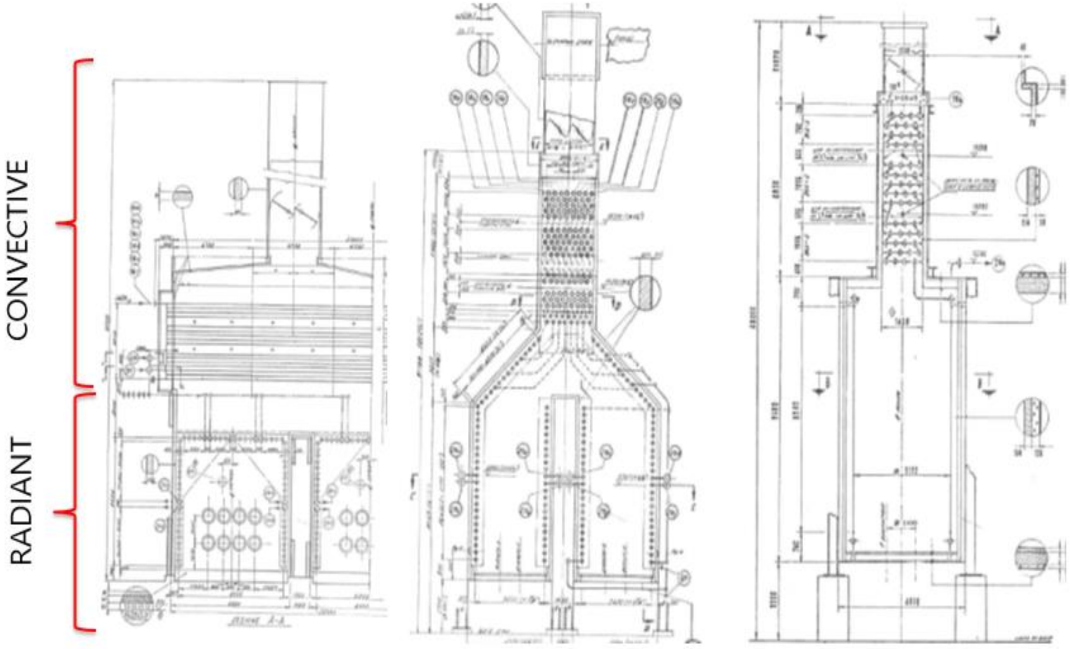
Piping Design based on:

- ✓ Static stability

$$\boxed{\sigma_{applied} \le S_{adm}}$$

- ✓ Creep life

$$\boxed{t_{design} \le t_{creep}}$$



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Fired Heater Furnaces – Damage Mechanisms

External Pipe Surface

- ✓ Oxidation

Internal Pipe Surface

- ✓ Carburization: embrittlement, thermal insulation
- ✓ Mechanical cleaning / erosion
- ✓ HT Sulphidation (Sulphur compounds, NAC)

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Metallurgy and Properties: P9 and Thor™115

GRADE 9:

introduced in 1940-1960 to improve corrosion resistance; martensitic microstructure

THOR™115:

Tenaris new martensitic steel for **high temperature** applications:

Improved steam oxidation resistance vs. 9Cr grades

Creep properties better than grade 91

Friendly in manufacturing and welding

	C	Mn	Si	Cr	Mo	V	Nb	N
Gr.9	0.1	0.4	0.6	**9.0**	1.0	-	-	-
Thor™115	0.1	0.4	0.4	**11.0**	0.5	0.2	0.04	0.05

✓ Both are ferritic steels, with similar **thermal expansion** and **thermal conductivity**.

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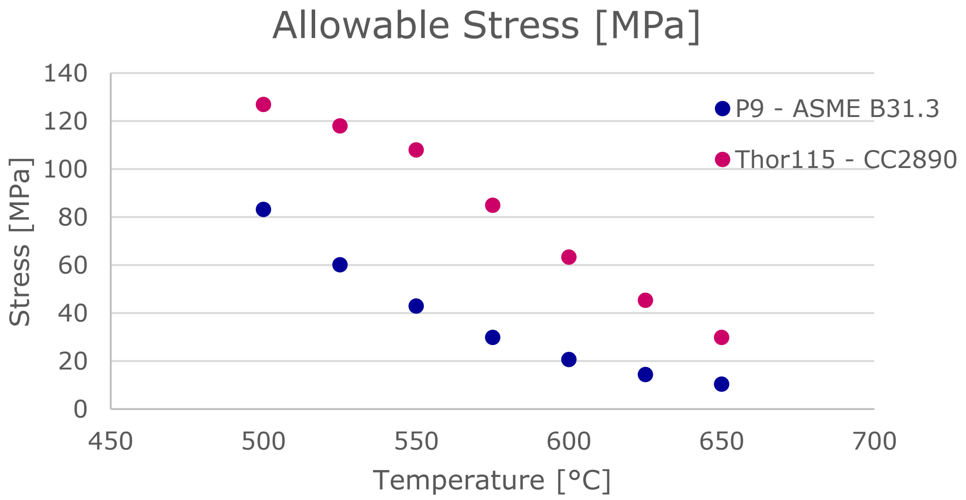
Life Model Development – Mechanical Data

Strength Data:

- ✓ P9: Table A-1 of ASME B31.3
- ✓ Thor™115: ASME BPVC.CC.BPV.S3-2017 Code Case 2890

Temperature °C	P9 [MPa]	THOR [MPa]
250	118	165
300	117	163
350	114	159
375	112	156
400	110	152
425	106	148
450	103	142
475	98,3	135
500	83,2	127
525	60,2	118
550	42,9	108
575	29,9	85
600	20,6	63,3
625	14,4	45,3
650	10,3	29,8



- ✓ Conventional creep initiation: T=575° C (P9: 520° C)

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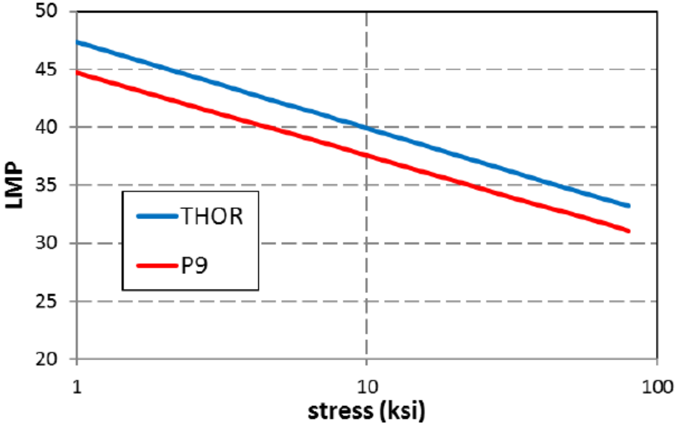
Life Model Development – Creep Data

CREEP DATA:

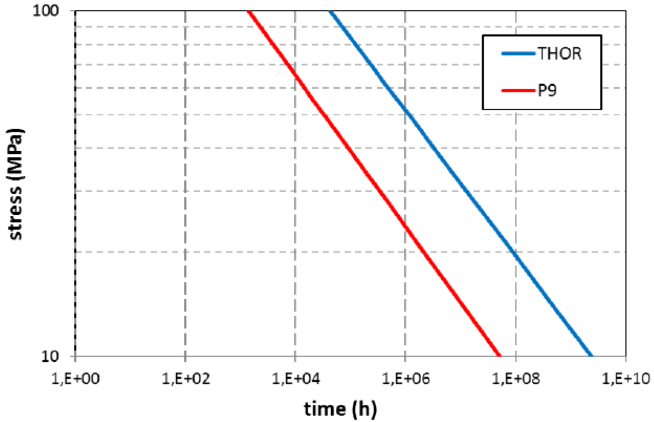
- ✓ P9: API 530 Table F.31
- ✓ Thor™115: creep tests database

Larson Miller Parameter [LMP] to correlate the remaining material life [t_{creep}] with operating temperature [T] and applied stress [$\sigma_{applied}$] (API 530 and API 579):



T=**600° C**

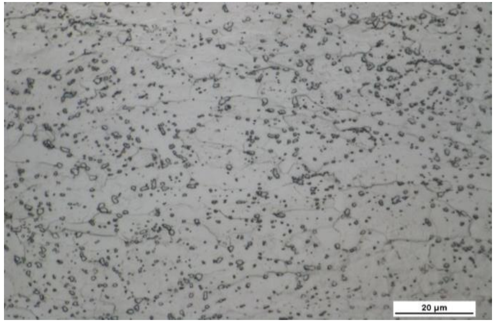
Thor™115 lasts 90 times more than P9

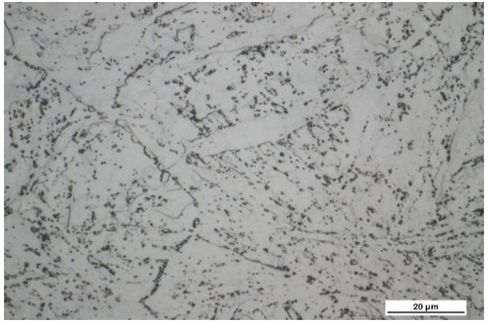


Life Model Development – from Stress to Hardness

In fired heaters **over-tempering** of the material causes:

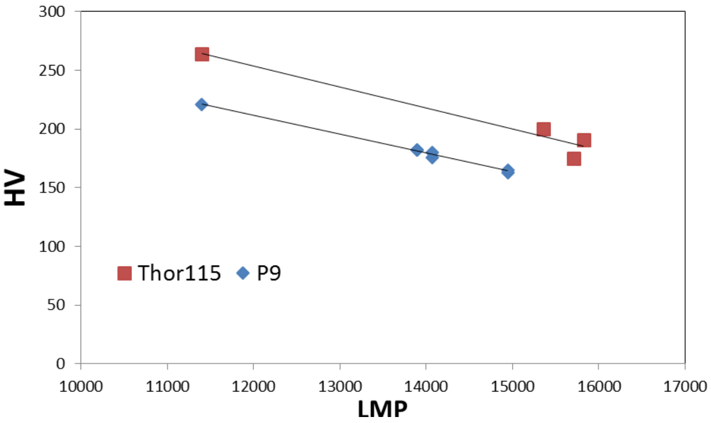
- ✓ carbides precipitation
- ✓ boundary cavity formation
- ✓ Hardness decrease (martensite structure vanishes) → S_{adm} decreases





M23C6 carbides evolution in both alloys at similar LMP

Hardness values of new material and crept specimens tested at 600° C were correlated to the exposure conditions through LMP (σ):



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Life Model Development – Corrosion Data

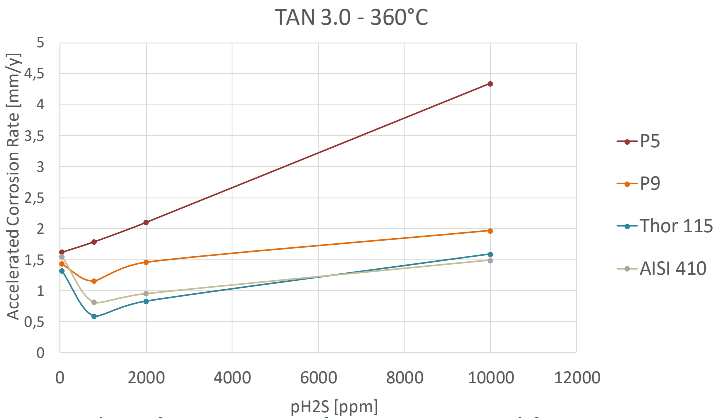
External Oxidation

API 571 and API 581 report Oxidation Rates (OR) vs. Temperature for several material classes :

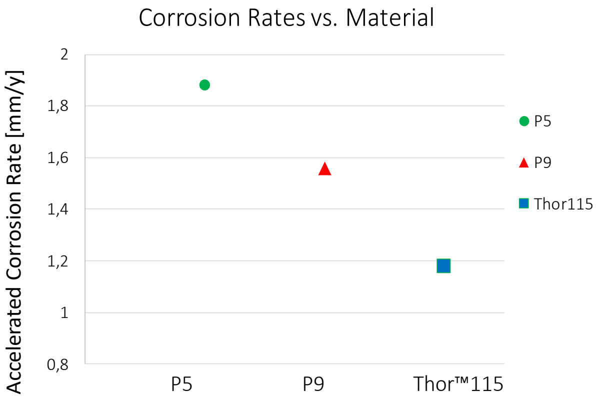
- ✓ 9Cr: **1 mpy** at 600° C
- ✓ 12Cr: **1 mpy** at 600° C

Internal Sulphidation

- ✓ ***Modified Mc Conomy curves*** (API 571 and API 581) report 9Cr and 12Cr Corrosion Rates (CR_{9Cr} > CR_{12Cr}).
- ✓ Thor™115 was already tested and compared with P9 in similar corrosion environments:



1. Pilot Plant at **ENI** (Venezia – Tech) - Tests in **naphthenic** and **sulphidic** environment



2. **HGO hydrotreating** pilot plant at **ADNOC** Refining Research Center

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Model Layout

Creep design:

- ✓ $\sigma_{applied}$ in furnaces is low → the design condition $\boxed{t_{design} \leq t_{creep}}$ can be disregarded, low creep damage

Static design:

- ✓ The applied stress increases due to thickness (WT) reduction caused by oxidation and corrosion:

$$\begin{cases} \sigma_{applied} = \dfrac{PD}{2WT} \\ WT = WT_0 - (OR + CR)\,t \end{cases}$$

- ✓ The allowable stress decreases with time (overtempering) as described by LMP law:

$$S_{adm} = S_0\, f\,(LMP)$$

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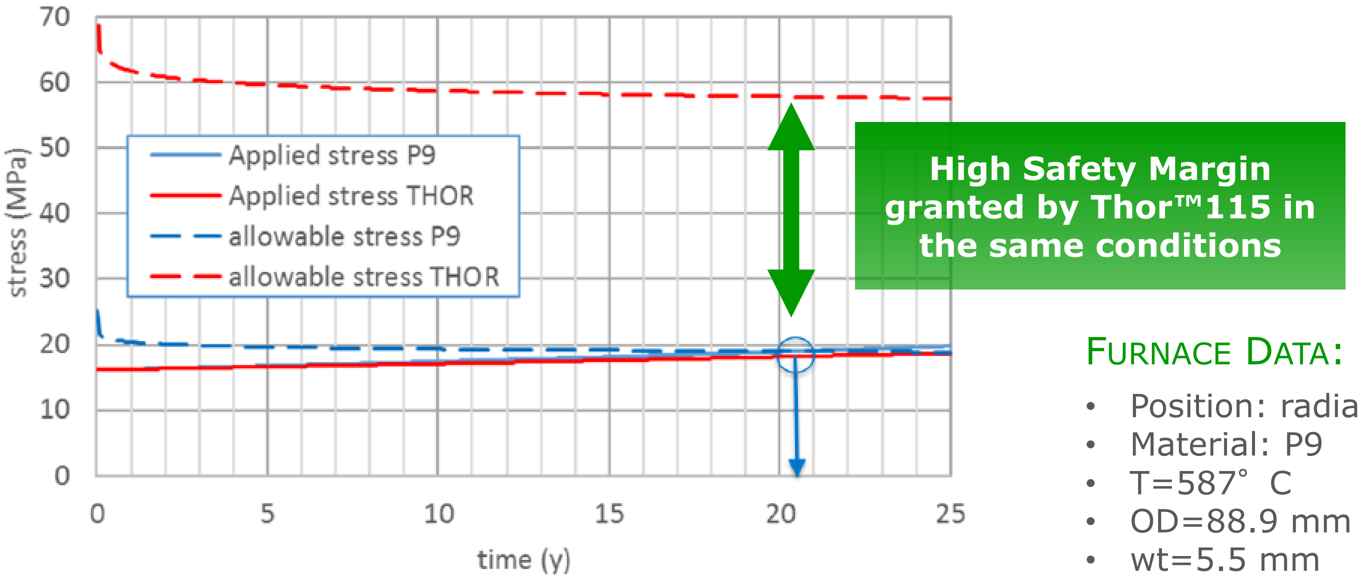
Model Validation – Real Case

A real case was used to verify the model, comparing P9 and Thor™115:



FURNACE DATA:

- Position: radiant coil
- Material: P9
- T=587° C
- OD=88.9 mm
- wt=5.5 mm
- P=20 bar
- OR=0.04 mm/y
- CR=0.0 mm/y

The model sets the P9 component life at 20.5 years.

From the service history, the coil was replaced after 22 years of service.

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Economic Evaluation: Shutdown Costs

Refineries shutdowns are scheduled as follows:

✓ For **creep controls**:
- After 100 kh +/-10% (10-12 years)
- Every 50 kh +/-10% (4-5 years)
- In case of defects, reduced schedule (1.5 years)

→ **20 days** stoppage

✓ Furnaces **clean up**:
- Every 2-2.5 years

✓ **General Refinery Turnaround** for maintenance:
- Every 4-5 years

→ **45-60 days** stoppage

Shutdown Costs

✓ Loss of Refinery production:

Loss of production = Refining Net Margin x Furnace Output

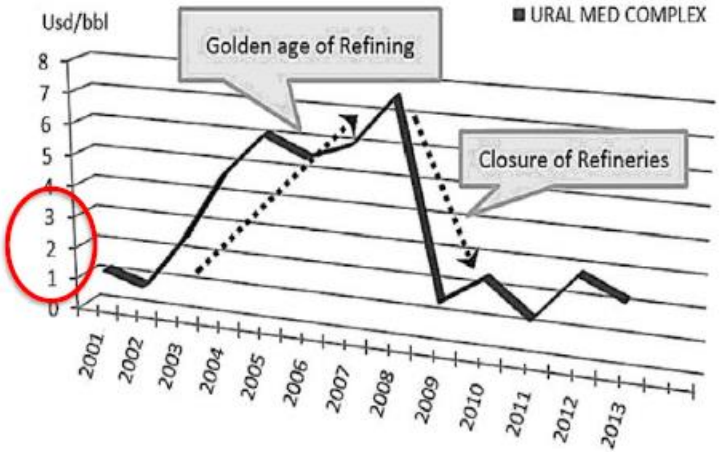
with

$$\textbf{Refining Net Margin}: \frac{\textbf{Total Refinery Sale}}{\textbf{Crude Cost + Operational Cost}}$$

Considering the last Refining Net Margin trend, the expected value is around **1-3 USD/barrel**

Furnace Outputs vary depending on the furnace and are around **200 ton/h**

→ 20 days shutdown = about **600 – 1000 K$** (if 100% furnace production lost)



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Shutdown Costs

- ✓ **Recoil costs**:

  20-50 ton of pipes = **100 – 200 K$** (material costs)

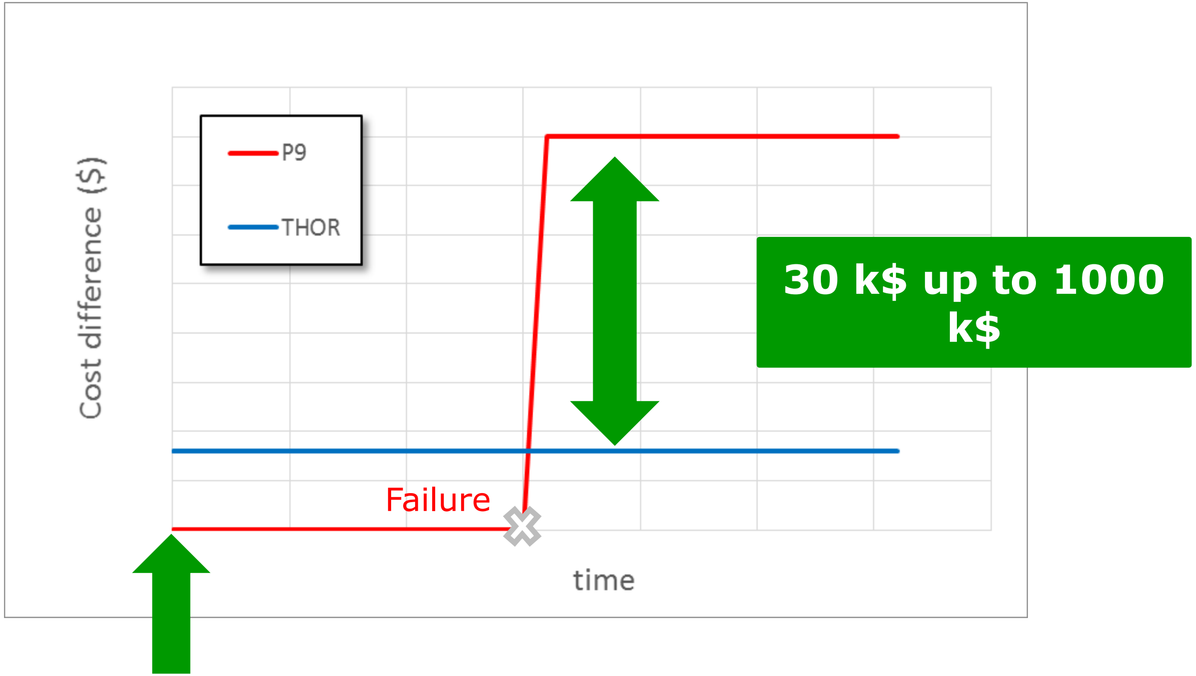
  → Thor™115 cost ≈ **1.1** P9 cost

  Additional costs: dismantling, rebuilding, manpower, scaffolding, safety, recommissioning

- ✓ **Inspection costs**:

  1 furnace NDT cost = **10 - 20 K$**

Economic Assessment



The initial investement of Thor™115 is **11%** higher than P9

P9 replacement introduces additional costs: **loss of production**, **inspection**, **construction, material substitution**

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Conclusions

- ✓ Fired heater furnaces are adopting P9 steel grade despite elevated temperatures
- ✓ Crudes have increased sulphur content and TAN, turning corrosion more critical
- ✓ Thor™115 steel grade has better performance with respect to P9 in terms of:
  - **Static and Creep resistance**
  - **Oxidation resistance**
  - **High Temperature Sulphidation resistance**
- ✓ The technical and economical comparison has shown **high advantage** to adopt Thor™115 in Furnaces application:
  - Higher safety margins
  - Low initial cost difference
  - Reduced maintenance costs

Appendix 9

Utilization of Permasense sensors in refineries

(Peter Fischbacher)

Rosemount Wireless Permasense Non-Intrusive Corrosion/Erosion Monitoring Solutions to Enhance Operational Profitability

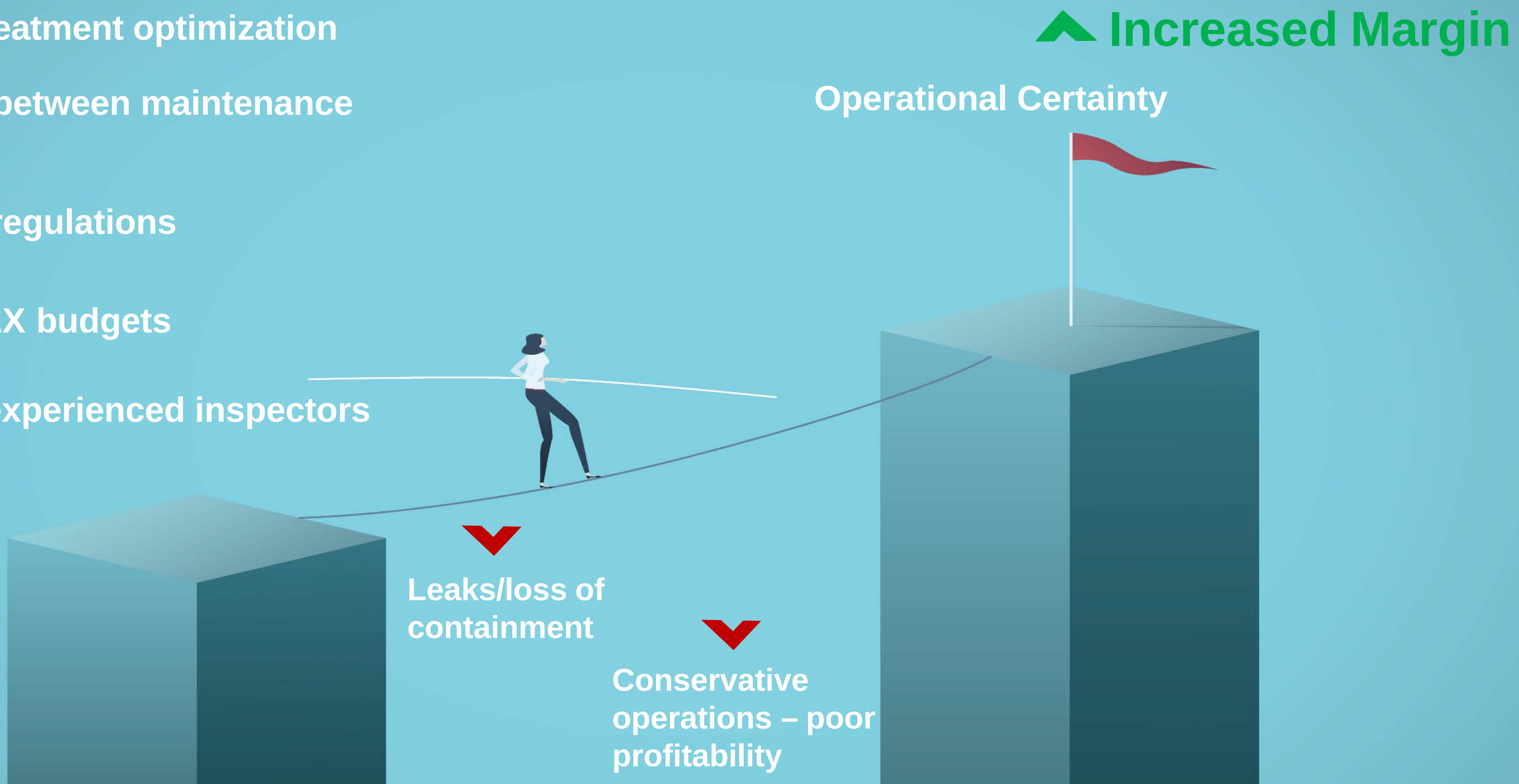
Online Corrosion Monitoring Update

EFC WP15   Corrosion Refinery Industry
11th September 2019 Meeting

Emerson Automation Solutions – Milano / Italy
PETER FISCHBACHER – PETER.FISCHBACHER@EMERSON.COM

Industry Challenges – Missing Asset Health Data Means Your Plant Is Not Being Driven to Its Maximum Capability

- **More variable feedstock quality**
- **Process & Treatment optimization**
- **Longer runs between maintenance solutions**
- **Tighter H&S regulations**
- **Tighter CAPEX budgets**
- **Shortage of experienced inspectors**



Top Downstream Applications and Solutions

- **Opportunity feedstock** – real time online corrosion data, effective and efficient asset integrity management, continuous production corrosive feedstock, payback within weeks

- **Process optimisation** – root cause analysis to minimise or even eliminate process attributed corrosion including material selection, to maximise production uptime, 25 to 50 sensors per unit operations, payback within weeks

- **Extended equipment life span and planned shutdown** – understanding of corrosion behaviour to implement self regulation asset management system, determine planned shutdown period, 25 to 50 sensors per unit operations, payback within weeks

- **Unmanned operations/reduction of OPEX** – to minimise human intervention especially to hazardous, inaccessible area or unmanned platform resulting in improved safety and reduction of operational cost, 25 to 50 sensors per platform, payback within months

- **Treatment optimisation** – monitor effectiveness of chemical injection, optimise chemical consumption and minimise inevitable corrosion, 15 to 25 sensors per unit operations, payback within months

Organic Chloride Contaminated Crude Oil Challenge

Druzhba Pipeline - Chlorine Contaminated Crude Oil

- Between April and June 2019, Central and Eastern Europe experienced interrupted deliveries of crude via the Druzhba pipeline
- Crude oil in the Druzhba pipeline was contaminated by organic chlorides
- Varying levels of organic chlorides of up to 150ppm
- Need for blending strategies & real time corrosion monitoring
- Petrochemical industry having the fear of contaminated feedstock from the refineries

The Druzhba pipeline in Belarus, where the contamination was first reported BELTA NEWS

Refining case study: The contaminated crude oil corrosion monitoring challenge

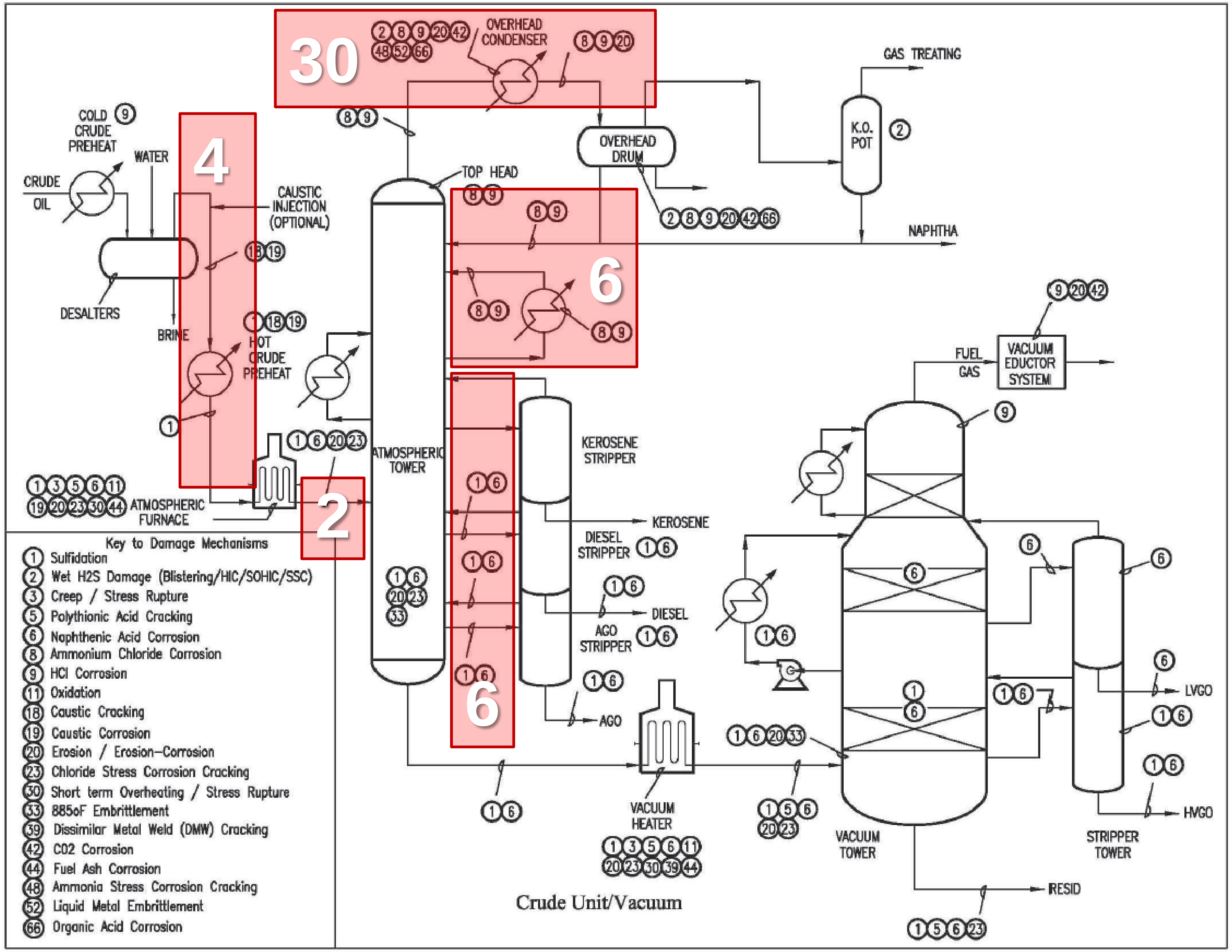
- Contaminated oil accelerates the corrosion process
  - organic chlorides: residues from chemicals used for well stimulation in the upstream oil production
- Expected to cause corrosion when process liquid condenses
- 4 units instrumented: ~50 sensors each
  - 3x crude distillation units
  - 1x isomerization unit

Case Study: Crude Unit Monitoring

- ~50 sensors per unit
- Corrosion monitoring used to evaluate mix rate of contaminated to uncontaminated crude

- Risk areas:
  1. Condensation in overhead line
     - Before and after inhibitor injection
     - Large area
  2. High temperature crude
  3. Sidecuts

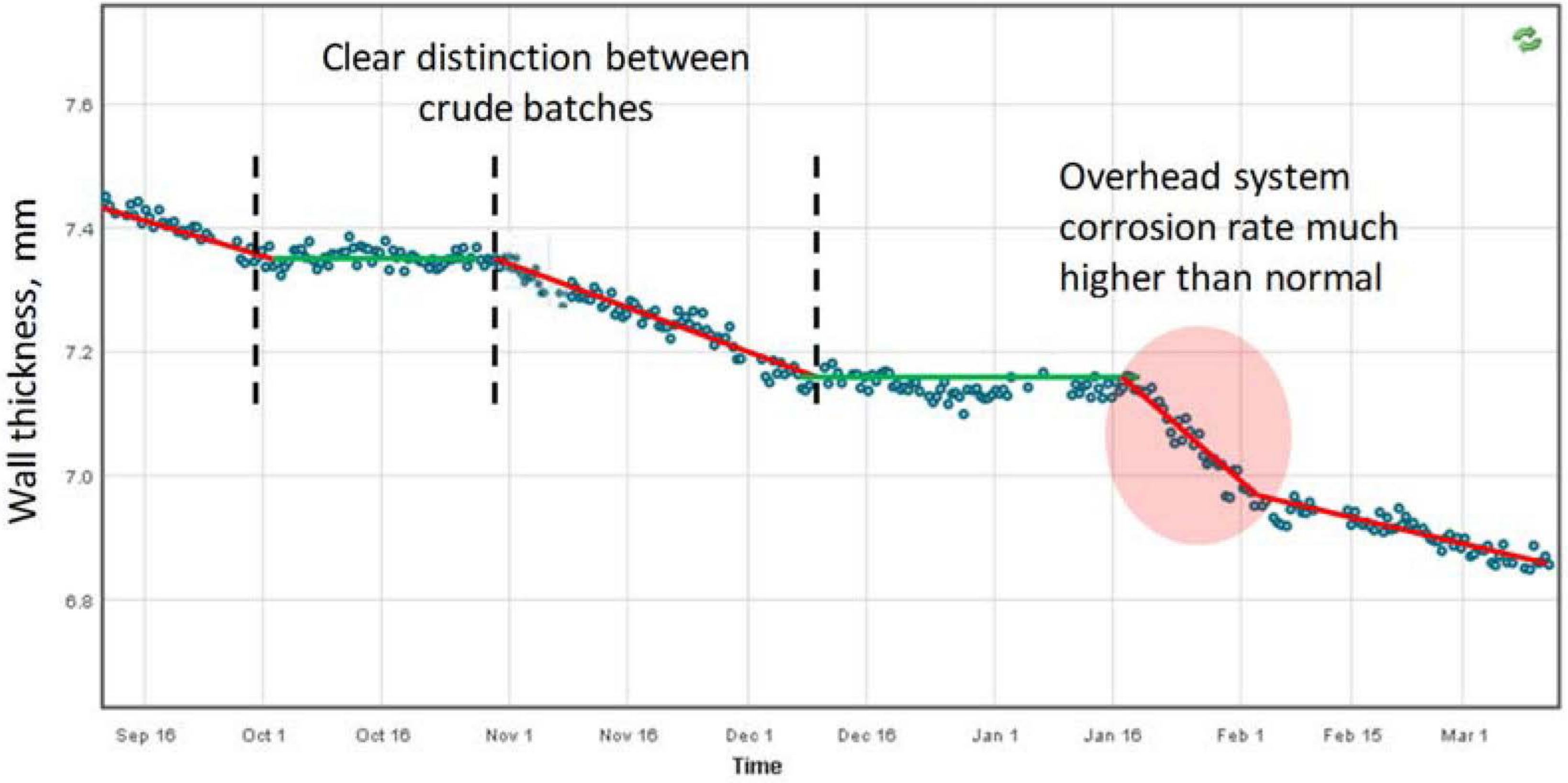
Figure 5-65 – Crude Unit / Vacuum



Caste Study: Track record in monitoring crude units for organic chlorides

- Another North American customer monitors distillation unit overhead system
- Period marked by the red dot showed markedly higher corrosion rates than normal
- Crude type was not unusual and had been processed previously
- No unusual process measurements

- Samples of the crude oil were analysed in lab
  - Result: high (and unusual) level of **organic chlorides**
- Customer now routinely tests every import of crude for organic acids to pre-empt any corrosion problems

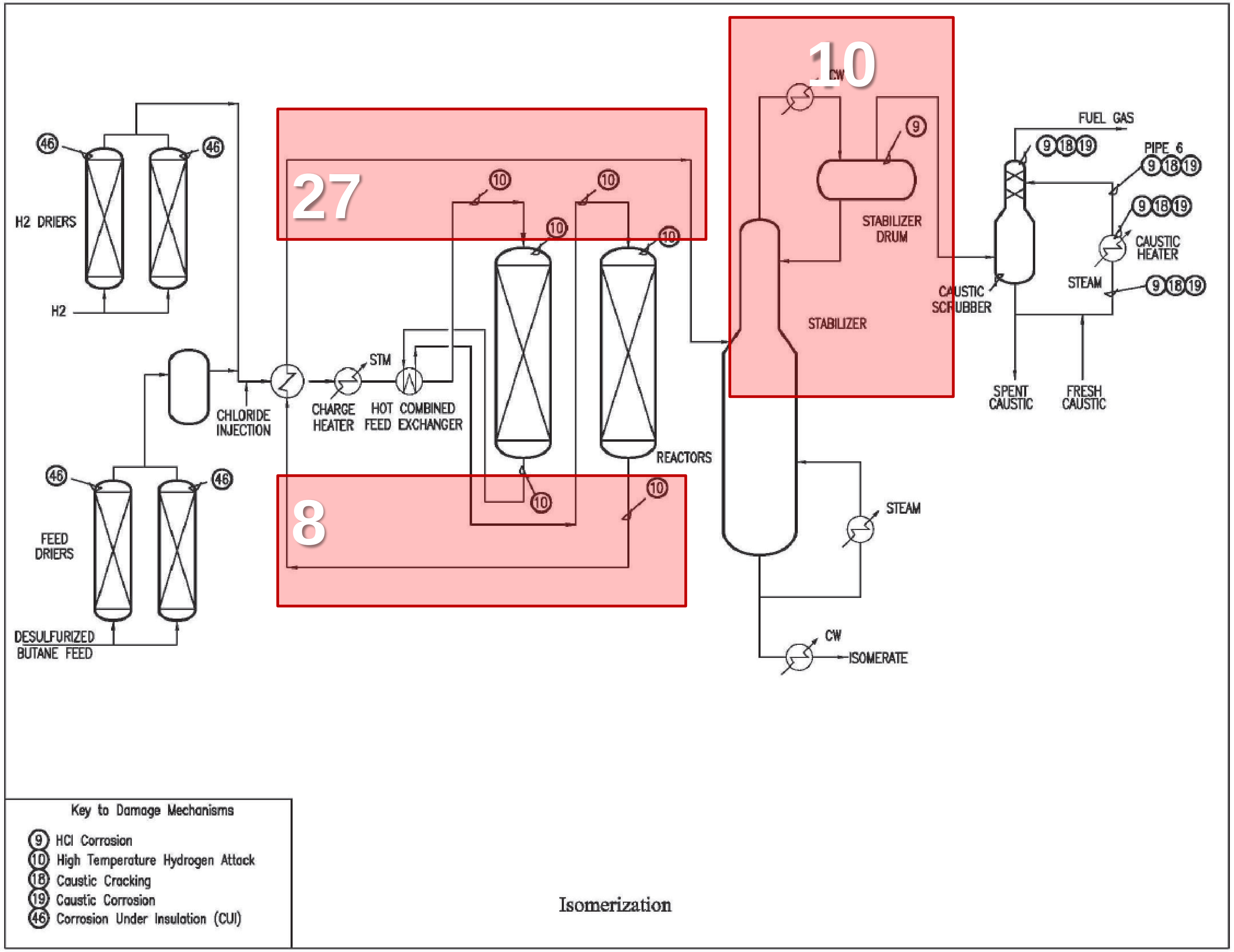


Case Study: Isomerization Unit Monitoring

- ~50 sensors per unit
- Monitoring corrosion caused by condensation

- Risk areas:
  1. Post-reaction mixture gradually cooling down
  2. Vapours/fumes from stabilizer

Figure 5-77 – Isomerization



Benefits of Online Corrosion Monitoring for Organic Chlorides

- More profitable blending strategy – higher chloride content
- Avoiding unplanned shutdowns
- Safer operations

Refinery Case Study
Amine Unit Corrosion Monitoring

EMERSON

Overview of Corrosion Issues in Amine Units

- Corrosion in amine units can be divided in two types
  - Wet acid gas corrosion of carbon steel from the reaction of CO_2 and H_2S with iron through a thin liquid film;
  - Amine solution corrosion of carbon steel in the presence of aqueous amine
- Key variables for assessing amine unit corrosion
  - Acid gas loading
  - Velocity and wall shear stress
  - Temperature
  - Impurities and heat stable amine salts
  - CO_2 to H_2S ratio
  - Choice of amine type

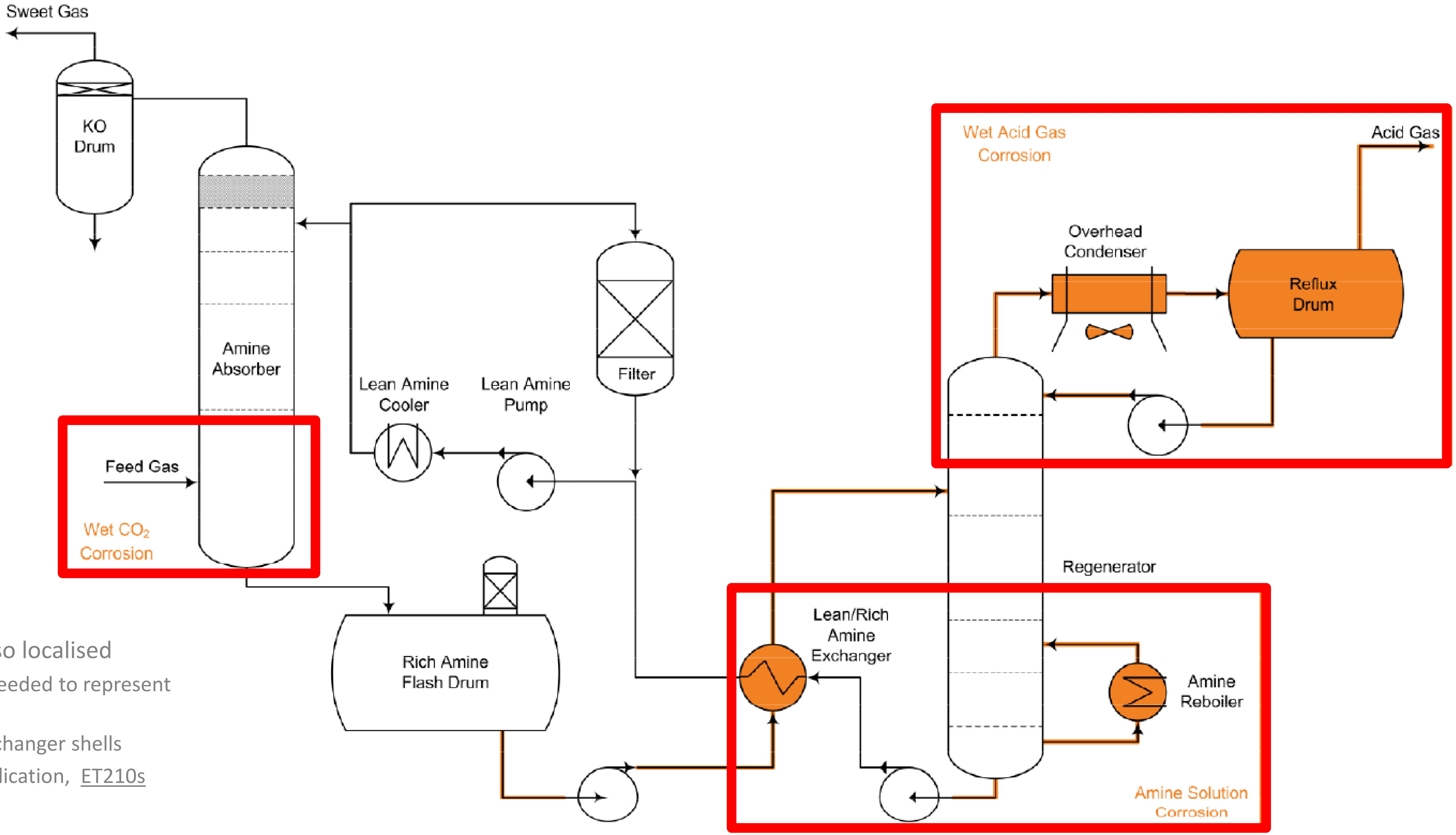
Averaged corrosion rates for carbon steel

Velocity [ft/s]	H2S loading as molar ratio to MEA 0.2	0.4	0.6	0.8
0	0	0	1	1
20	8	12	12	12
40	12	14	16	20
60	13	16	20	43
80	16	18	25	66

(dark green)	< 5 mpy
(light green)	5 - 10 mpy
(yellow)	10 - 15 mpy
(amber)	15 - 20 mpy
(orange)	20 - 50 mpy
(red)	> 50 mpy

Figure above shows the predicted variation of corrosion rates for carbon steel with amine acid gas loading and velocity. This shows that, as would be expected, high rich amine H2S loading combined with high velocity results in higher corrosion rates.

Amine Unit Process Overview



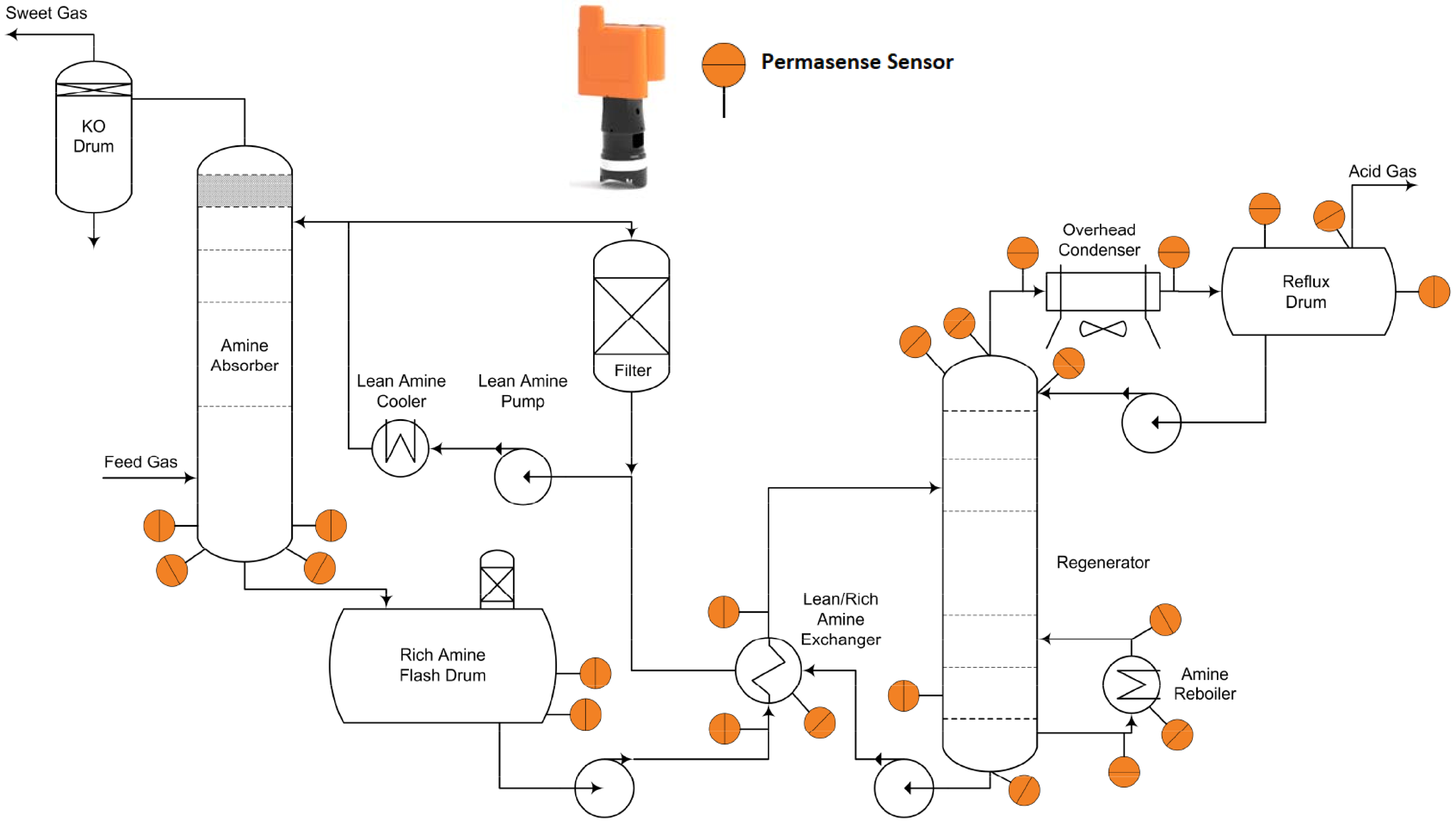
Corrosion issues

- High gas loading
- Heat stable salts
- Amine degradation
- Oxygen contamination

Corrosion is uniform and not so localised

- Fewer measurements needed to represent entire system
- Elbows, bends, tees, exchanger shells
- Lower temperature application, ET210s

Permasense Solution for Amine Units

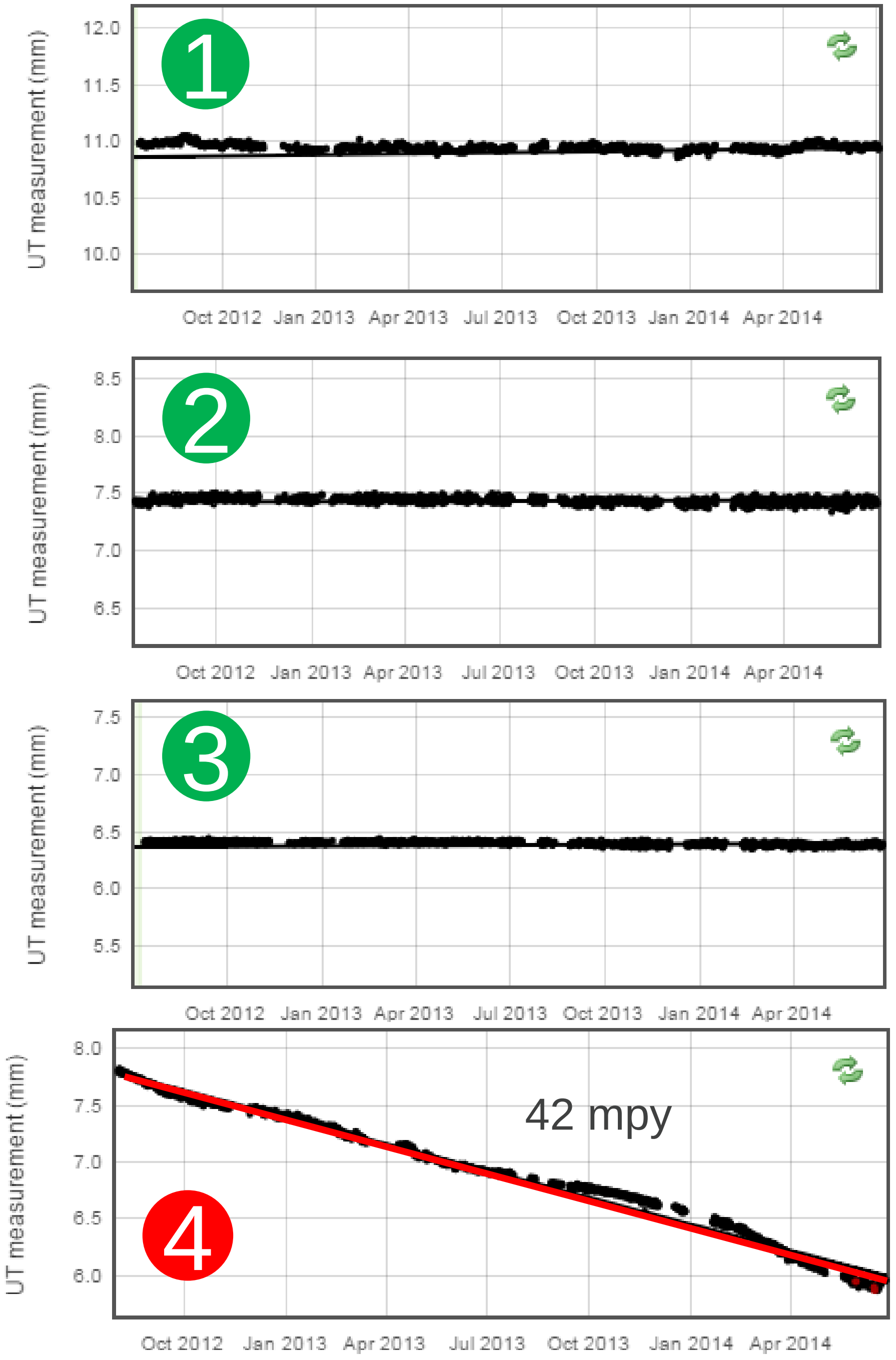


Permasense Solution for Amine Units

- Continuous wall thickness measurement sensors are ideally suited to monitor corrosion in the highest risk areas of amine units

- The monitoring data enables engineers to
  - Reliably determine if corrosion is taking place
  - Supporting the management of unit integrity between planned shutdowns
  - Understanding the correlation between corrosion rates and process conditions
  - Optimizing corrosion monitoring prevention & mitigation measures

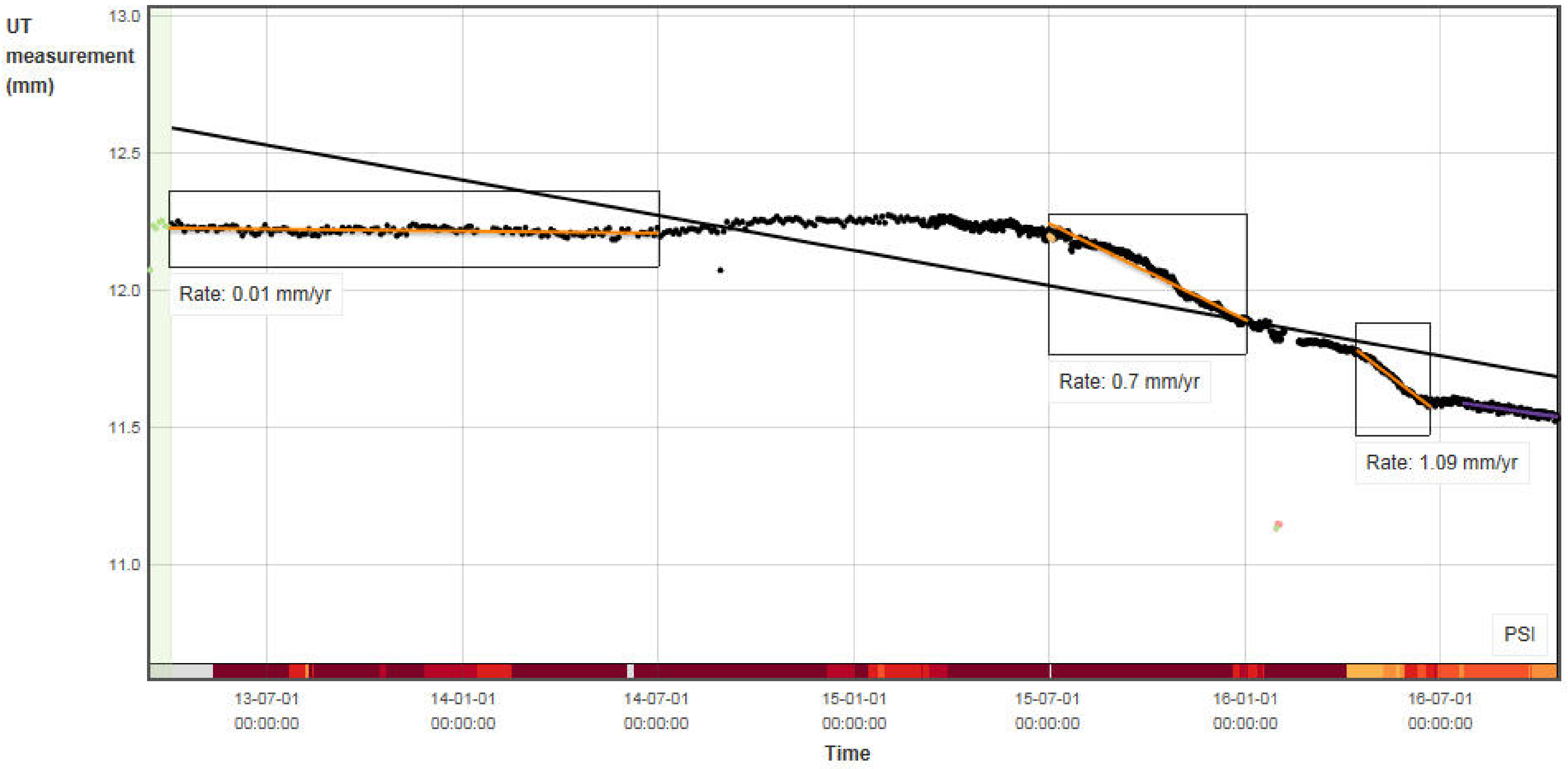
Case Study: Preventing Unplanned Outages – Amine unit



- Refinery with four amine absorber / regeneration trains
- All similarly configured, all stainless steel – corrosion NOT expected
  - Much faster and **unexpected** corrosion in train 4
    - 1 year to retirement even in stainless !
  - High CO_2 content feed due to preferential routing of FCC off-gas to train 4
  - Carbonic acid attack mechanism
  - Feeds redistributed to dilute effect of CO_2 corrosion across trains and extend run length

Early warning & enable decision making on process optimization to extend equipment life span

Case Study: Amine Regenerator – Process Optimization



- Historically controlled amine dump/top-up to heat stable salts level of ≤1

  Opex savings from fewer amine changes – targeted 1.5, then 2

  Reboiler outlet corrosion monitored

  Rising corrosion rate trend over time corresponding to increasing heat stable salts content

- Trade-off operating cost saving against equipment replacement cost

Commercial Impact of Amine Unit Shutdowns

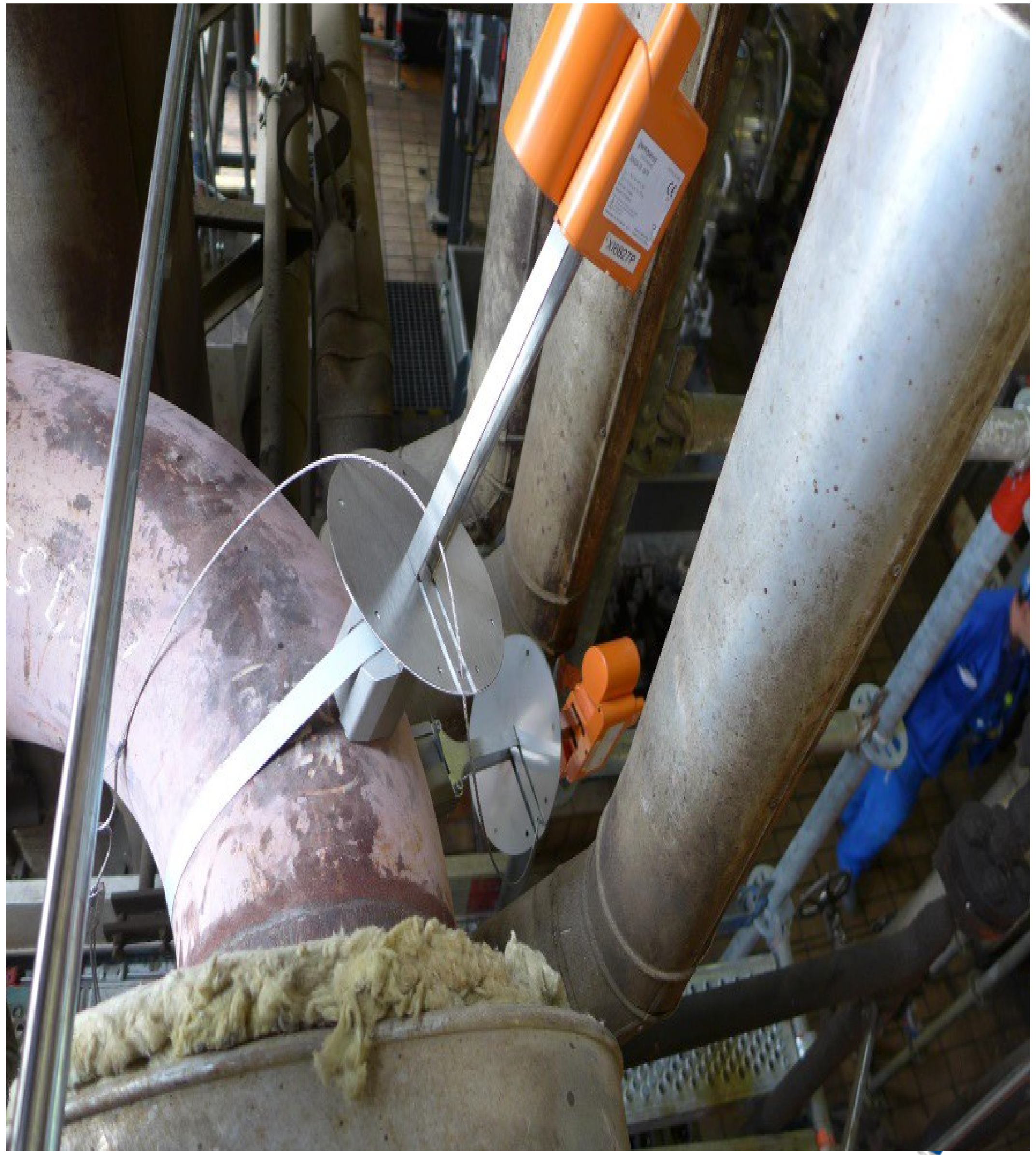
- The commercial impact of an amine system outage on a given plant will depend on the type of plant, its specific configuration and the feed quality, but is often significant

- Amine units often operated at significantly higher processing rates and amine H2S loading
  - This causes limits in the flexibility that the processing facility has to shut down the amine system for repairs in the event of a corrosion-induced leak, as the risk of H2S gas evolution

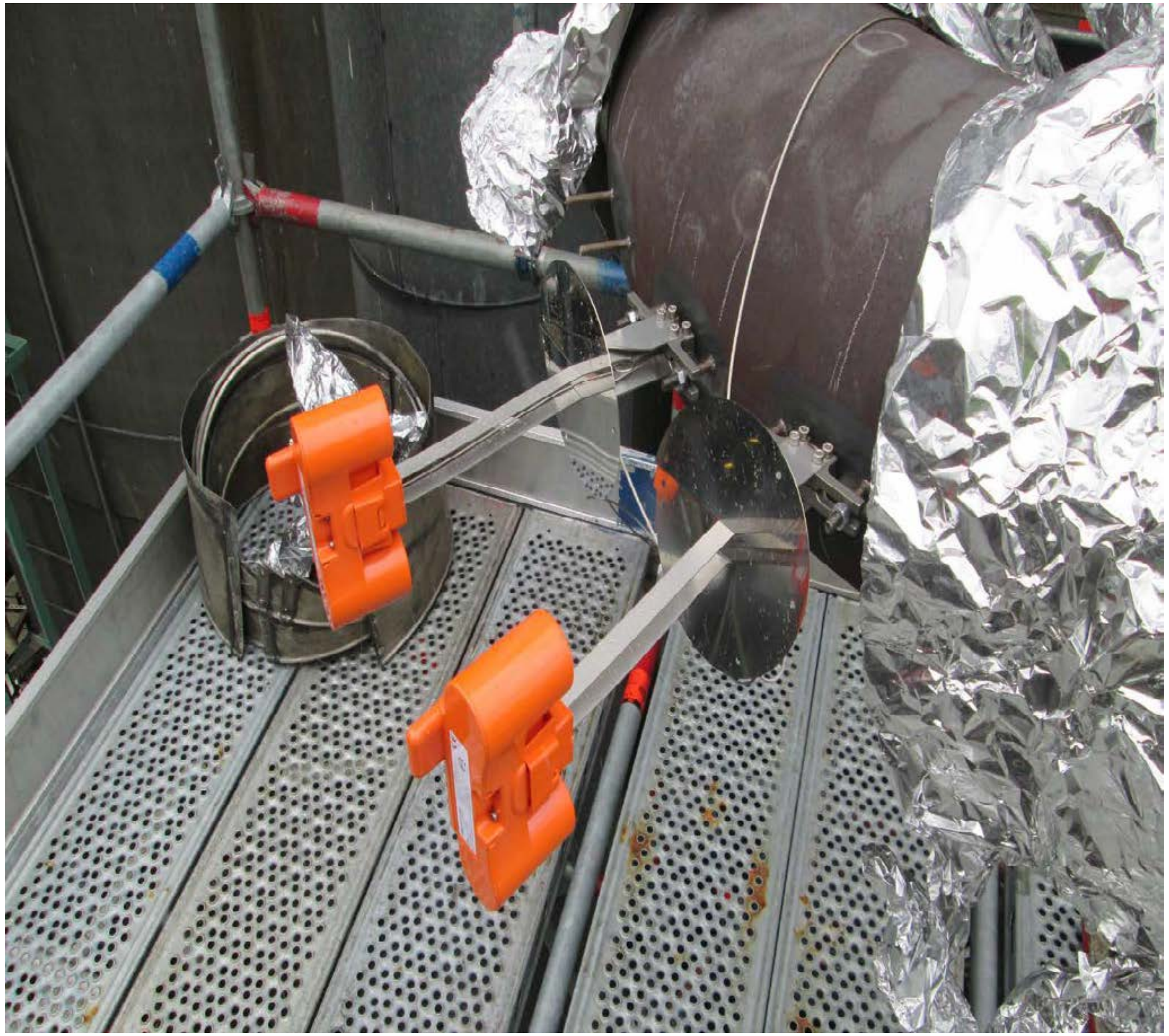
- Without storage for rich amine, the facility is forced to limit the H2S load on the amine system by, for example:
  - Change of feedstock (heavy, high sulphur crudes changed to light, lower sulphur, and more expensive feeds),
  - Reduced production rate (lower natural gas feed rate to a gas processing platform or onshore plant)
  - Change of production mode (yielding high sulphur, raw gas oil to storage for

Sensor Mounting

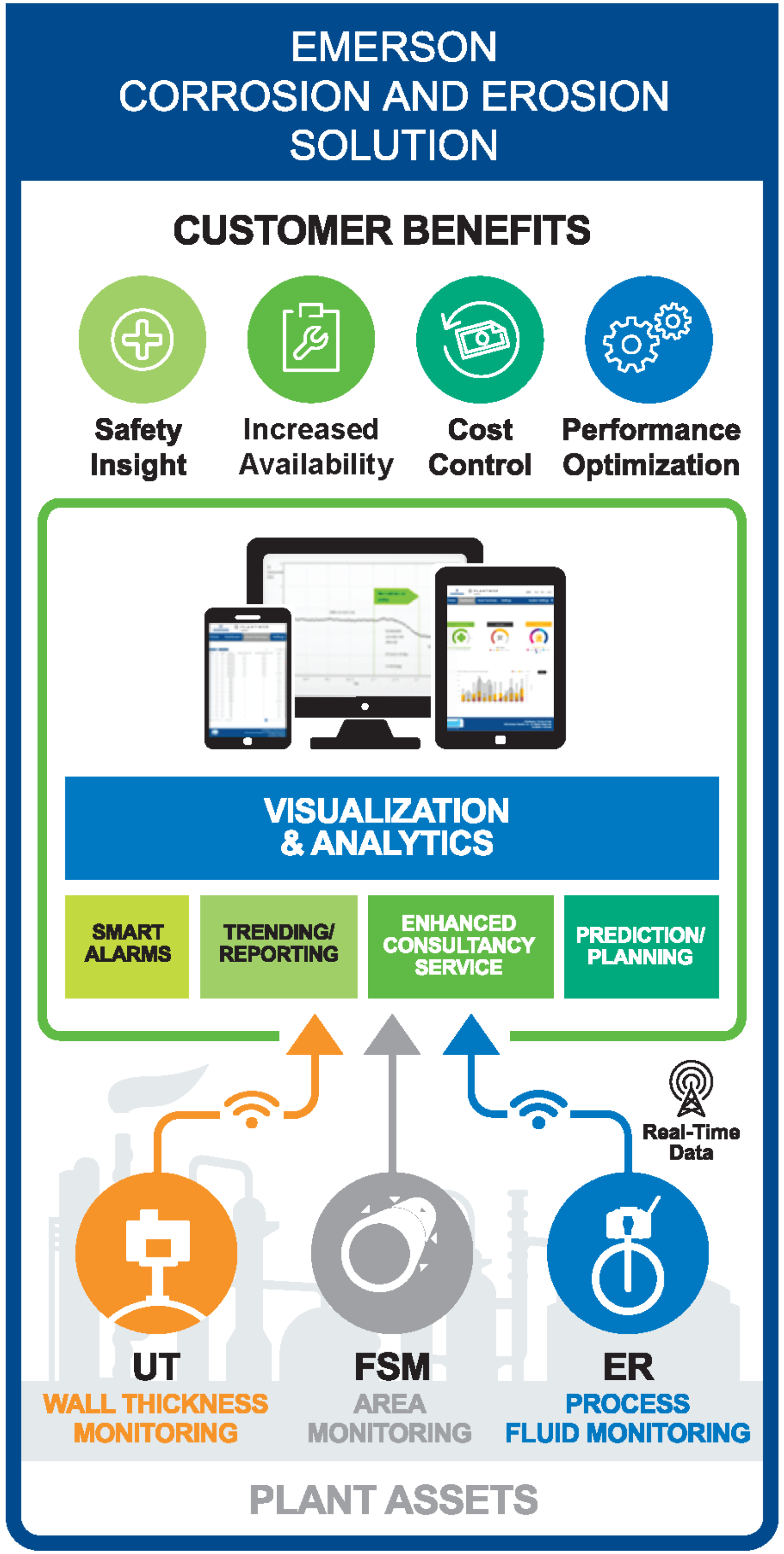
Sensor Installation Examples

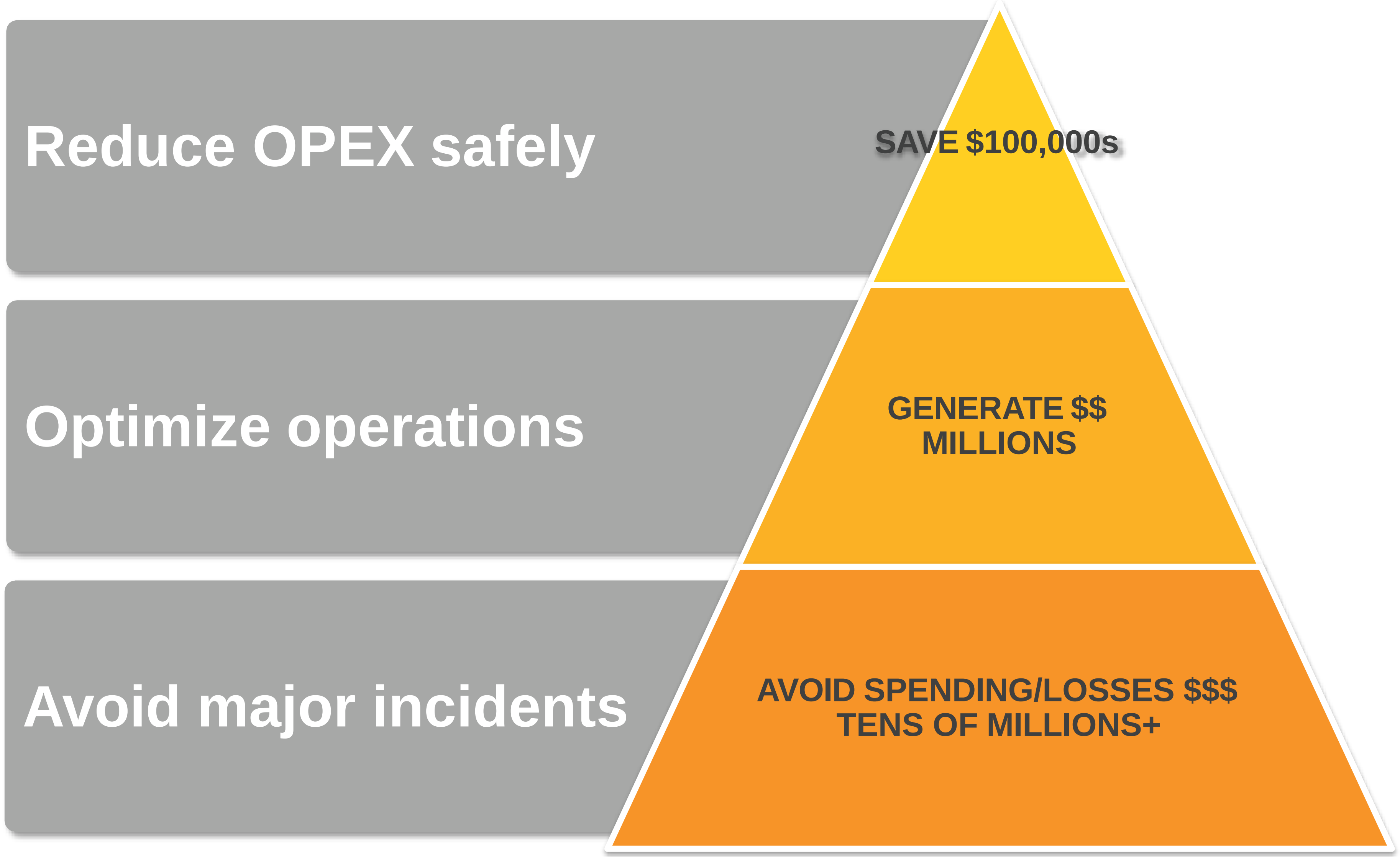


Sensor Installation Examples



Emerson solutions help meet future business demands safely





Appendix 10

A new hydrogen flux monitor with inspection and multipoint extended monitoring capabilities

(Frank Dean)

Eurocorr 2019

Seville 11 Sept 2019

WP15 meeting

Hydrosteel 6500

A new hydrogen flux monitor with extended monitoring capability.

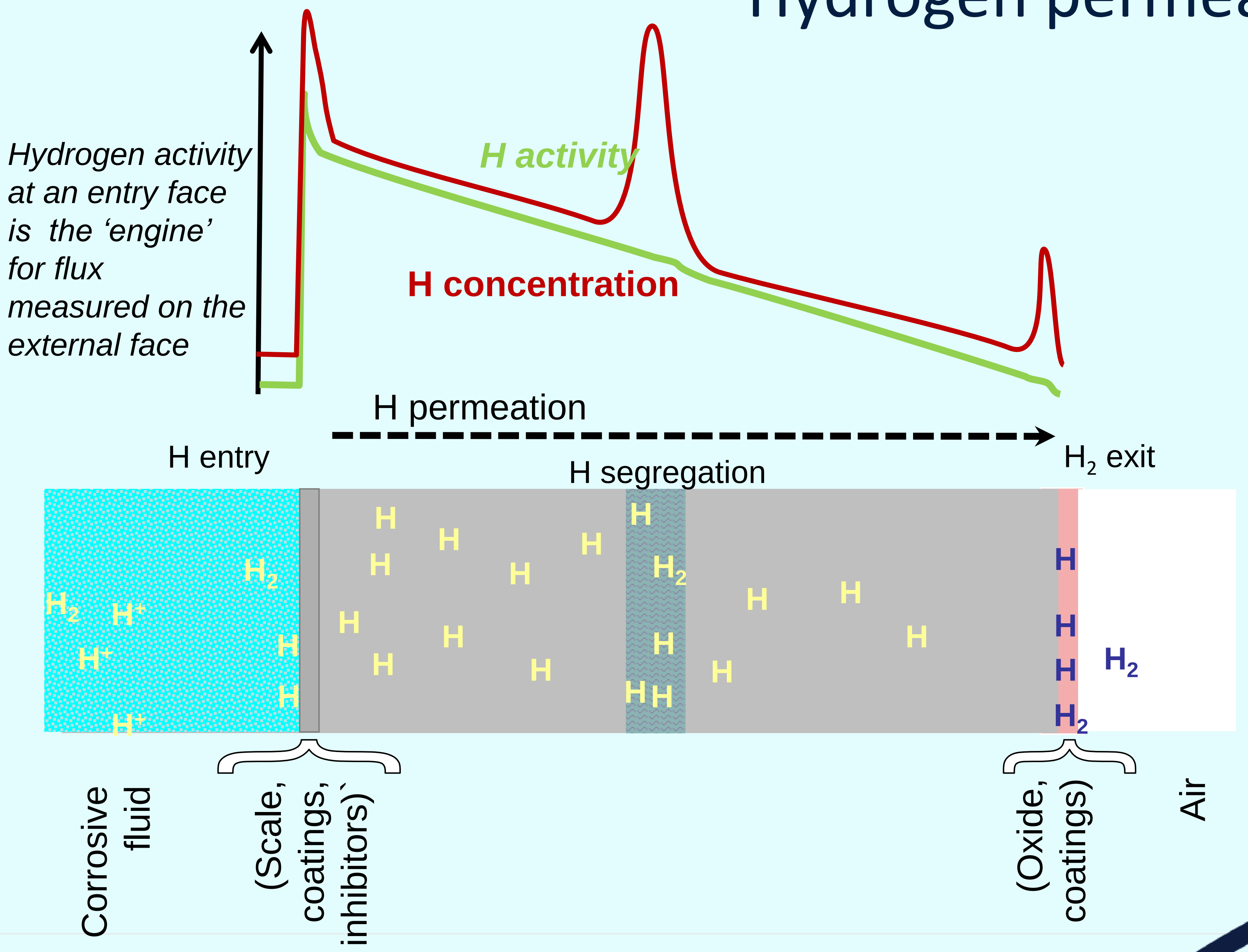
Frank Dean, consultant
frank.dean@ionscience.com

ION

Measure corrosion and hydrogen damage. *In real time. Non-intrusively.*

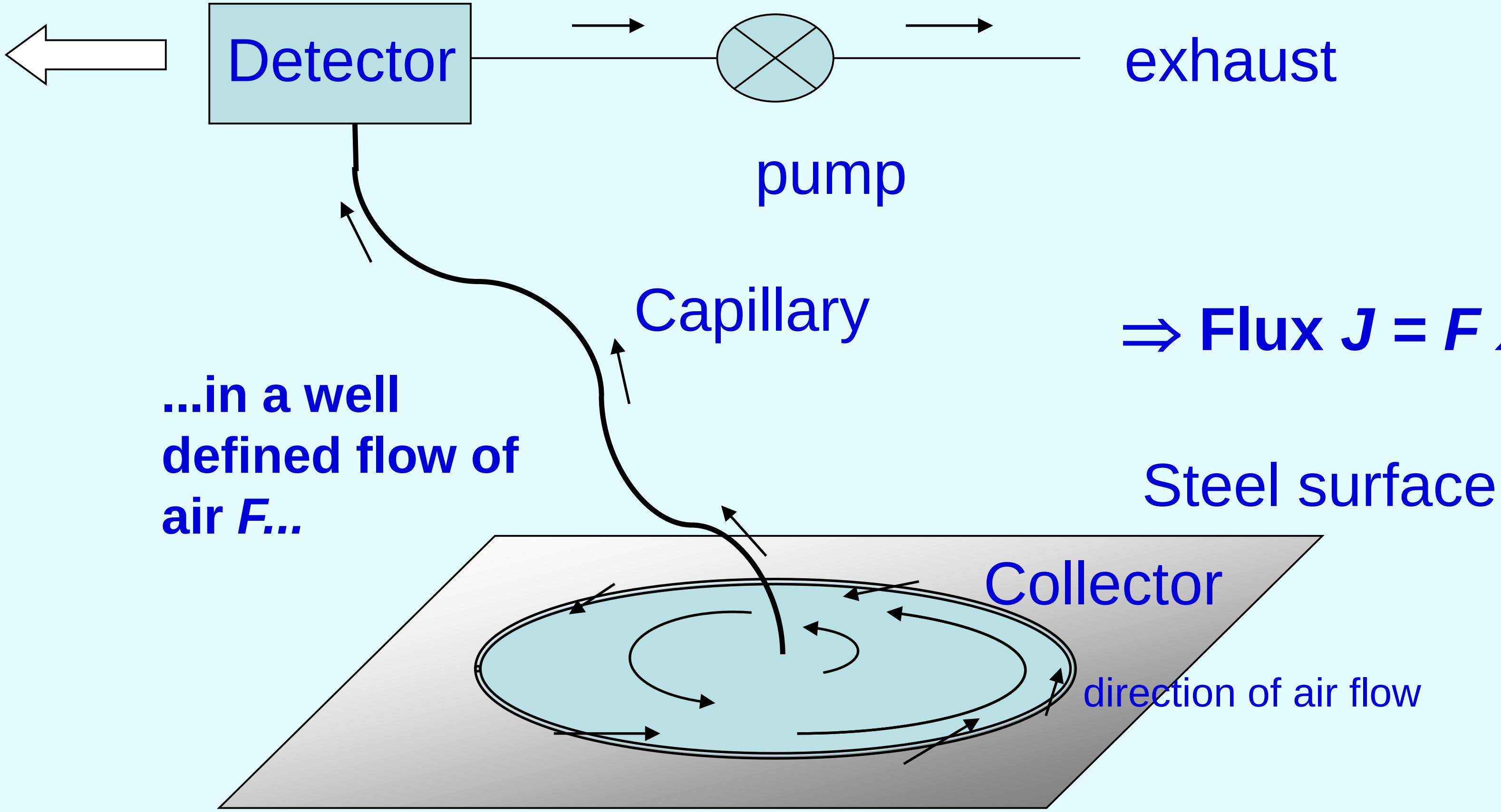
Ver. 190907

Hydrogen permeation schematic



Principle of operation

...increases the H_2 concentration in air by *c*...



...in a well defined flow of air *F*...

⇒ Flux *J* = *F* x *c* / *A*

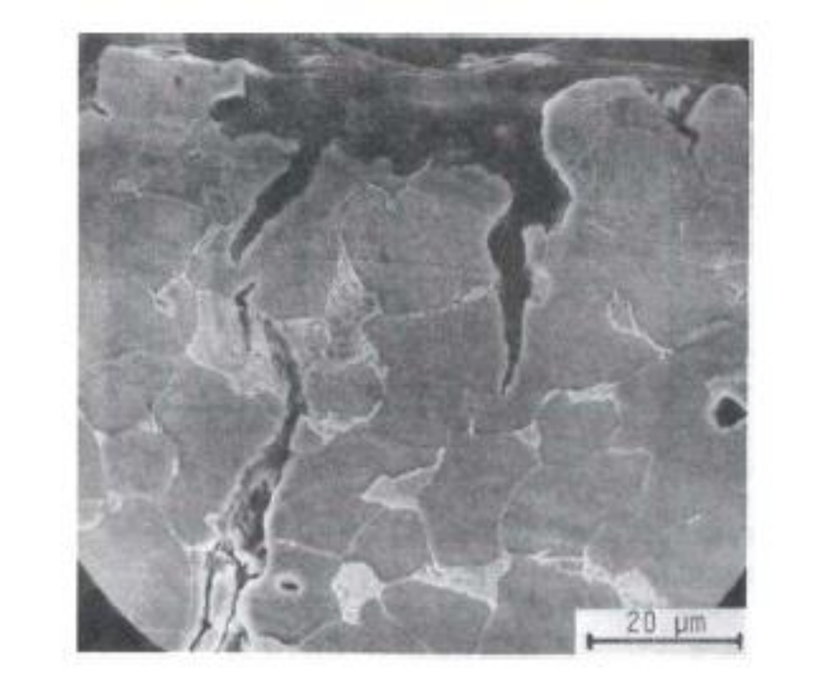
Hydrogen captured from a well defined area, *A*...

Main industrial interests in hydrogen flux

Corrosive wall loss

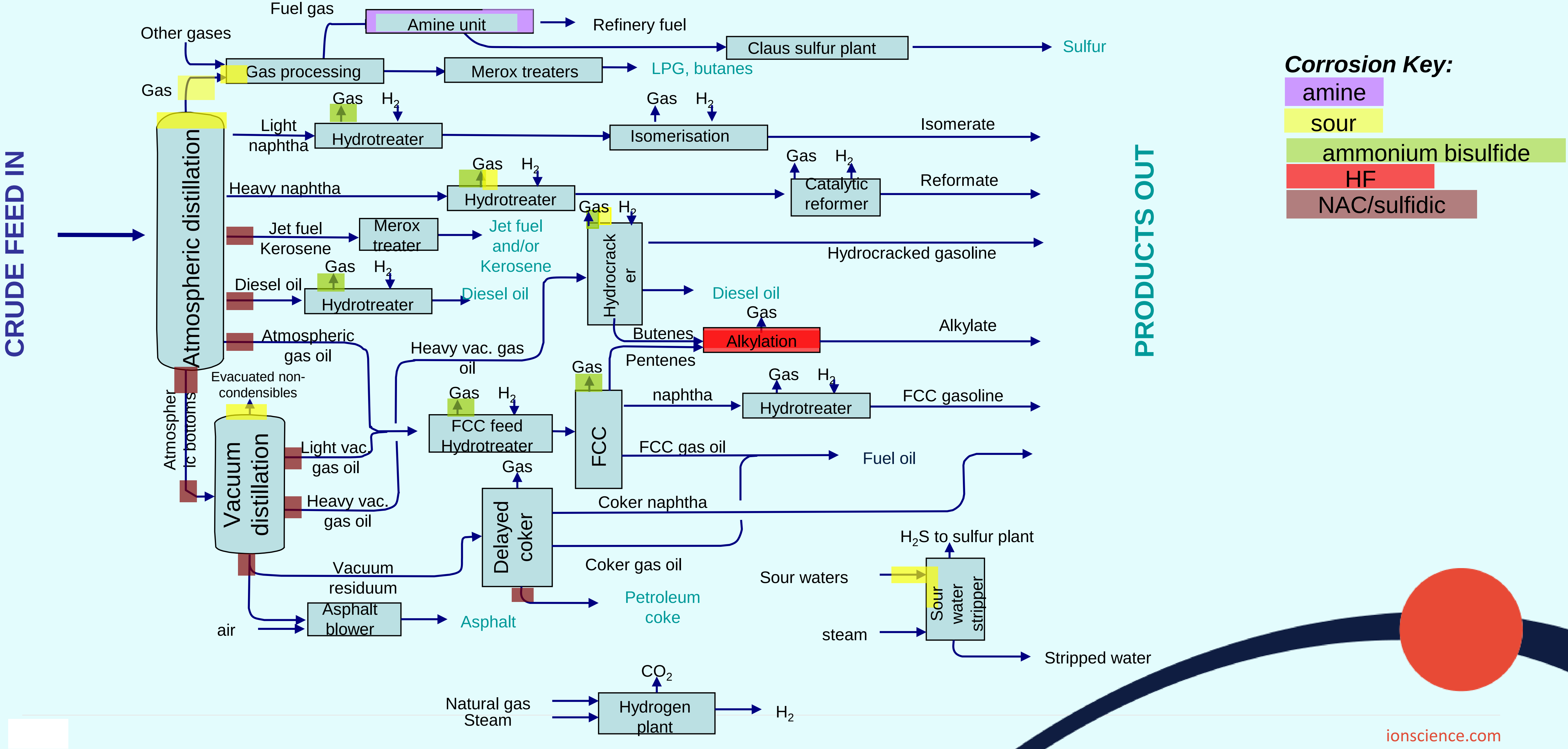
T. Batzinger, A May, C. Lester, K. Kutty , P. Allison, 16th World Conference on NDT, 2004, Montreal, Canada

…and hydrogen damage (HIC)

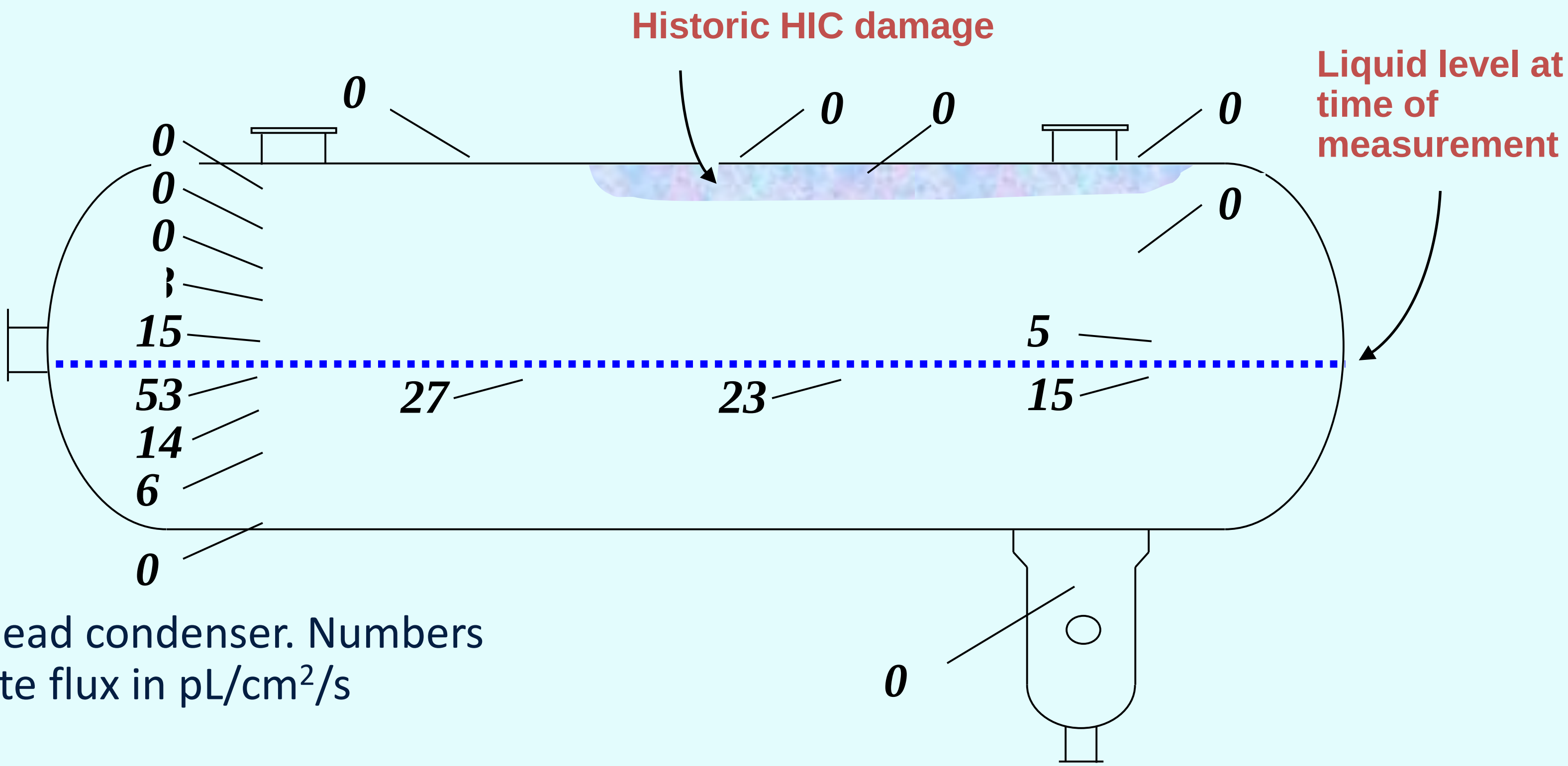


W.Bruckoff *et.al.*, *Corrosion '85*, Paper 389, NACE conference series, Boston, Mass. 1985.

Refinery corrosion detected with Hydrosteel



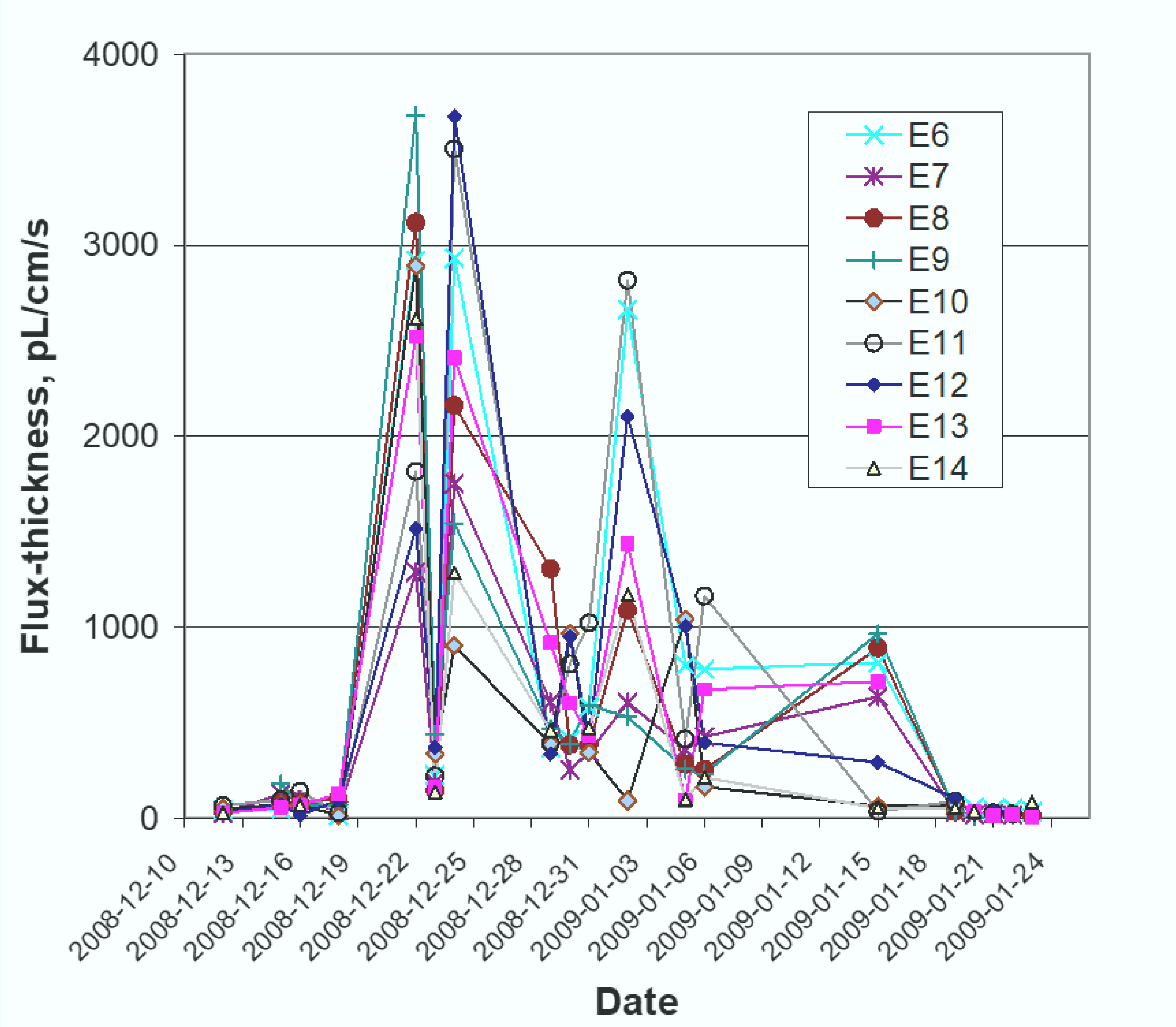
Multipoint spot measurements: episodic crack risk

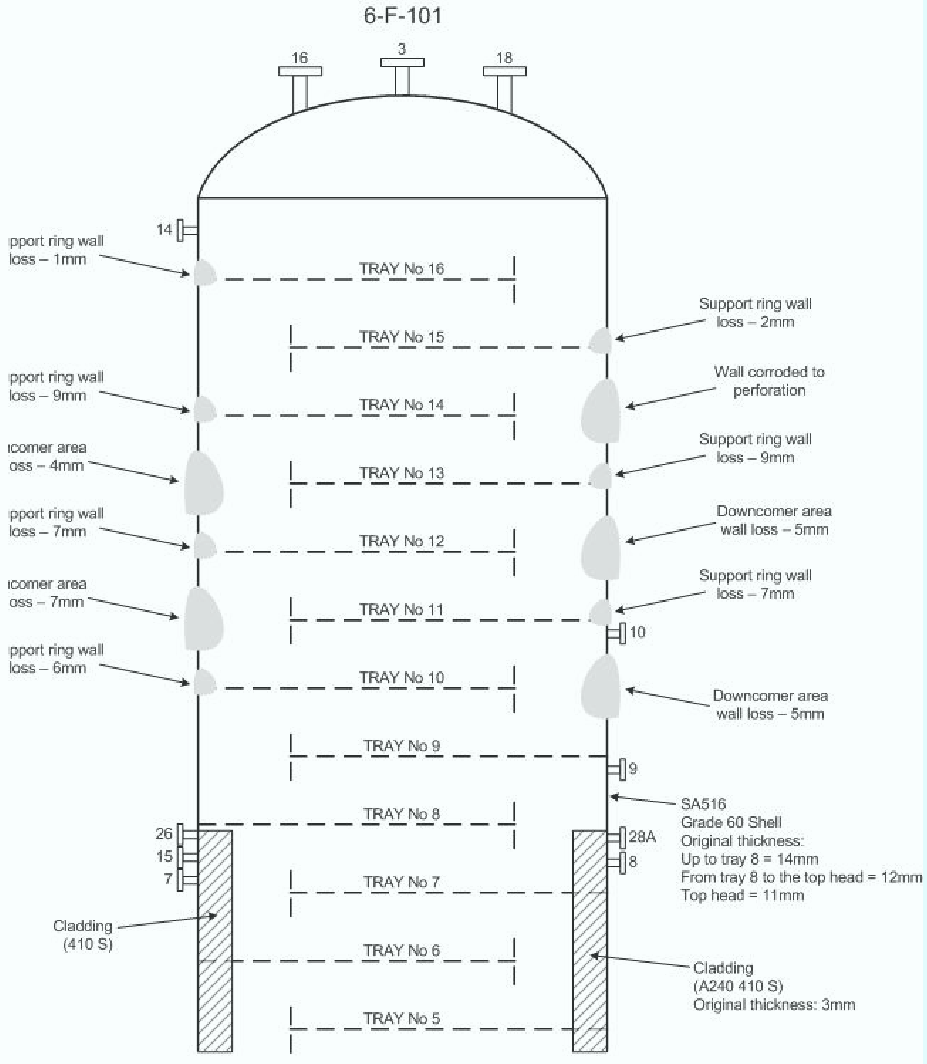


Overhead condenser. Numbers indicate flux in pL/cm²/s

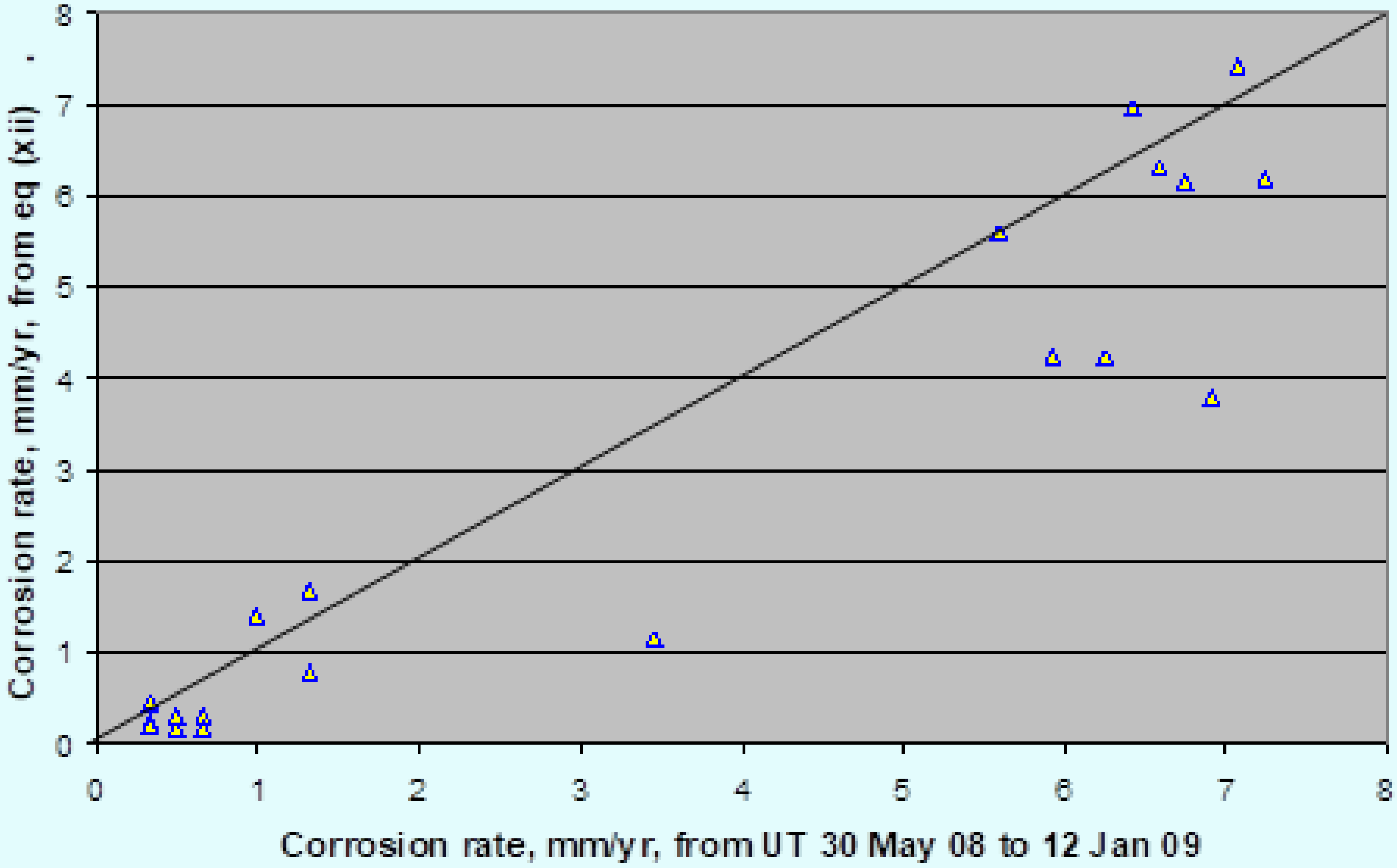
To identify a HIC conditions, episode, at least two monitoring points are required

Multipoint spot measurements: high temperature corrosion (1)





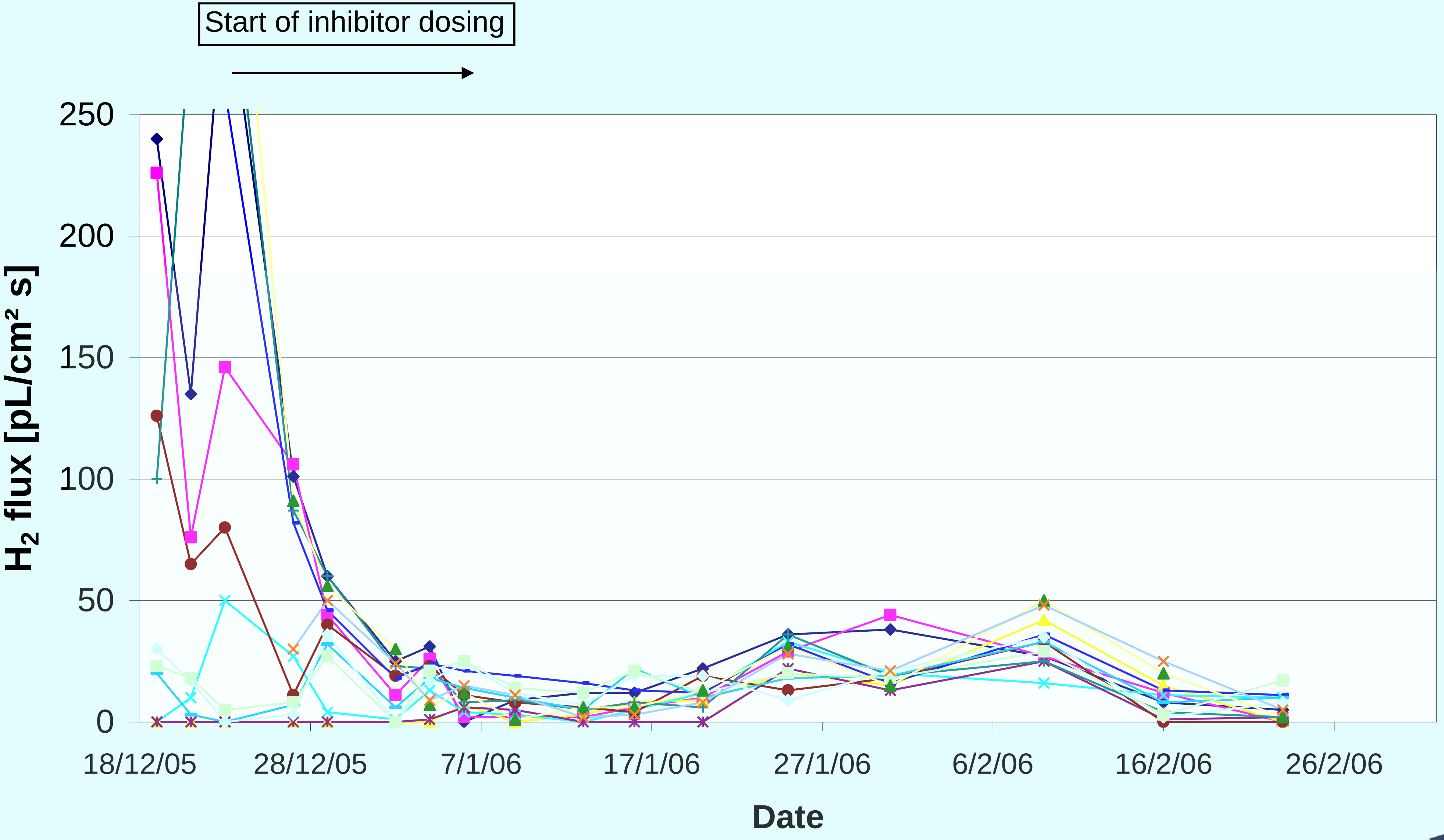
Multipoint spot measurements: high temperature corrosion (2)



Flux monitor data for up to a few months at multiple points at a few points will assure full realisation of corrosion severity over a typical corrosion epoch

Illustrations: J.M.O'Kane, T.F.Rudd, D.Cooke, S.W.Powell, F.W.H.Dean, *Corrosion 2010*, Paper 10351, NACE Conf. Series., 2010.

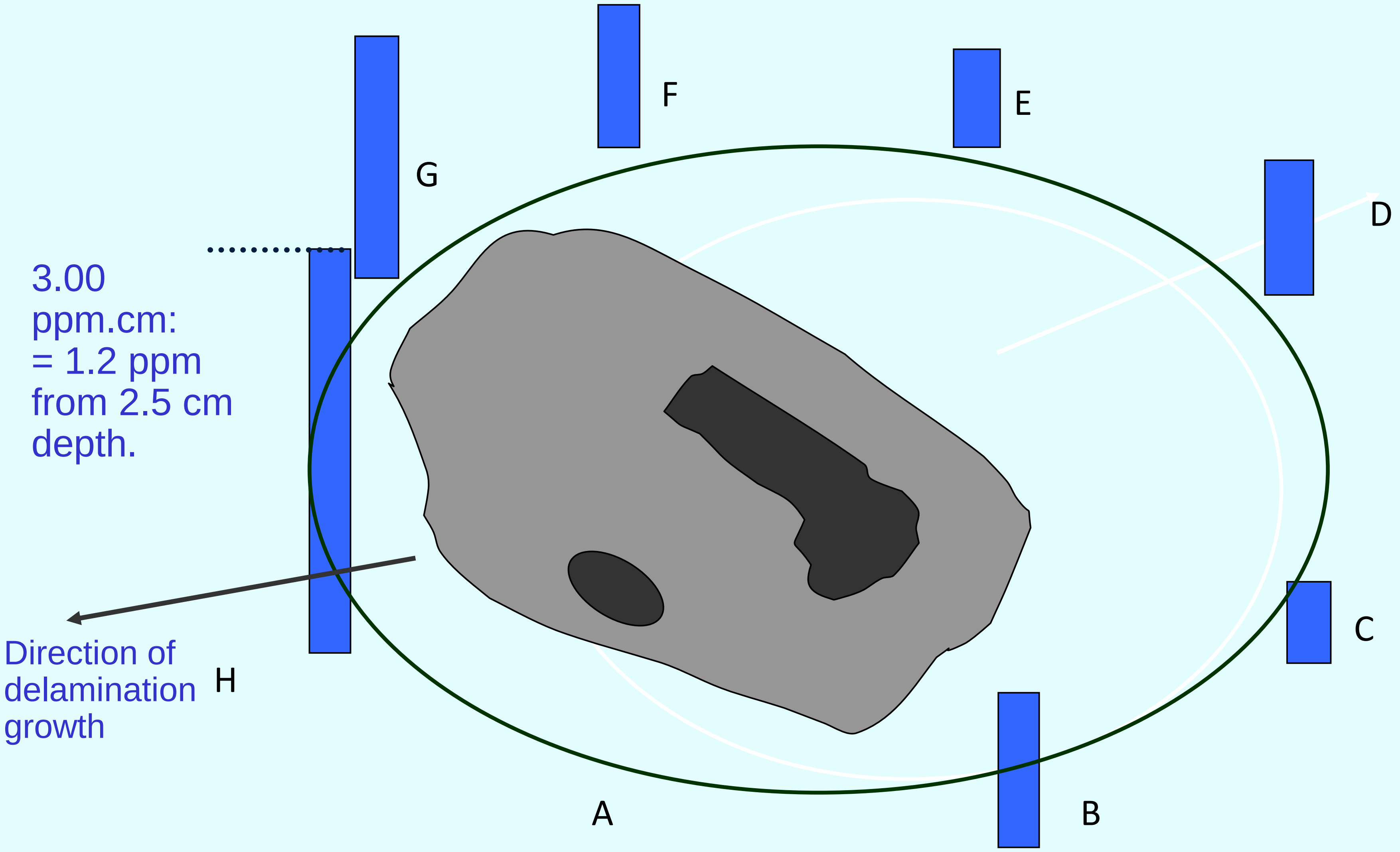
Multipoint spot measurements: HIC risk



Automated monitoring of flux at multiple points would save time.

Illustration: B.Otzitz, A.Gourzoulidou, Frank Dean, Klaus Bernemann, *Petroleum Technology Quarterly*, **2** (2009), 102.

Multipoint spot measurements: hydrogen bakeout



Automated monitoring of flux at multiple points would assure full bakeout.

C.N.Brown, M.J.Carroll, F.W.H.Dean, J.H.Harrison, A.Kettle, Corrosion 2004, NACE, Paper 04478.

Overview of Hydrosteel 6500

[1] Ruggedised field analyser with program operation and data monitoring capability.

[2] New 150 mm high sensitivity probe

[3] New 60 mm low sensitivity probe

[4] Steel clad flexible sample conduit – up to 10 m length

[5] Four ports for sequential flux monitoring

[6] Staubli® connectors afford easy pneumatic fitting to ports.

[7] Battery charge connector.

[8] USB connector for data download and program upload.

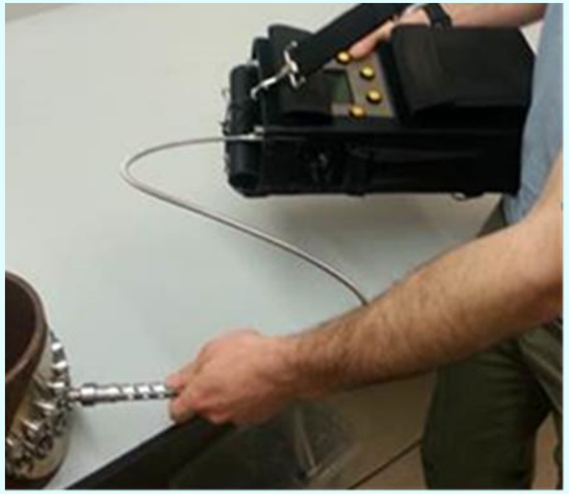
[9] Robust push button finger operation

[10] Large display with backlight

[11] Provision for wireless communication and networking

ATEX certification.

Application features and benefits of Hydrosteel

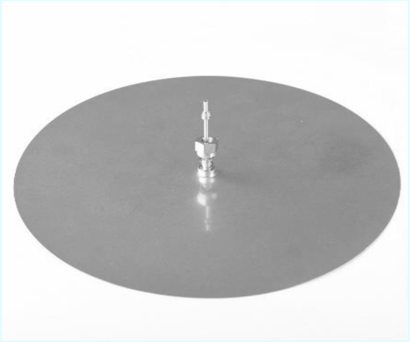


- wide dynamic range
- fast response
- simple to use
- no consumables
- usually no surface prep
- adapts to pipe > 3.5”
- operates upside down
- useable to 500 °C
- monitors up to four locations for up to three months

- measures active corrosion and crack risk, non-intrusively

Hydrosteel 6500: spot flux kit

Analyser and harness



Conduit

SR large roaming probe

LR large roaming probe

Hydrosteel 6500 spot monitoring

Simultaneous flux measurement evaluation

Add 4 L NACE B soln (pH 3.6), mag flea, stock H_2S

Shot blast to SA 2.5 std

Butyl rubber seals

6.7 in dia, 9 mm wall seemless C steel pipe

Acrylic end piece

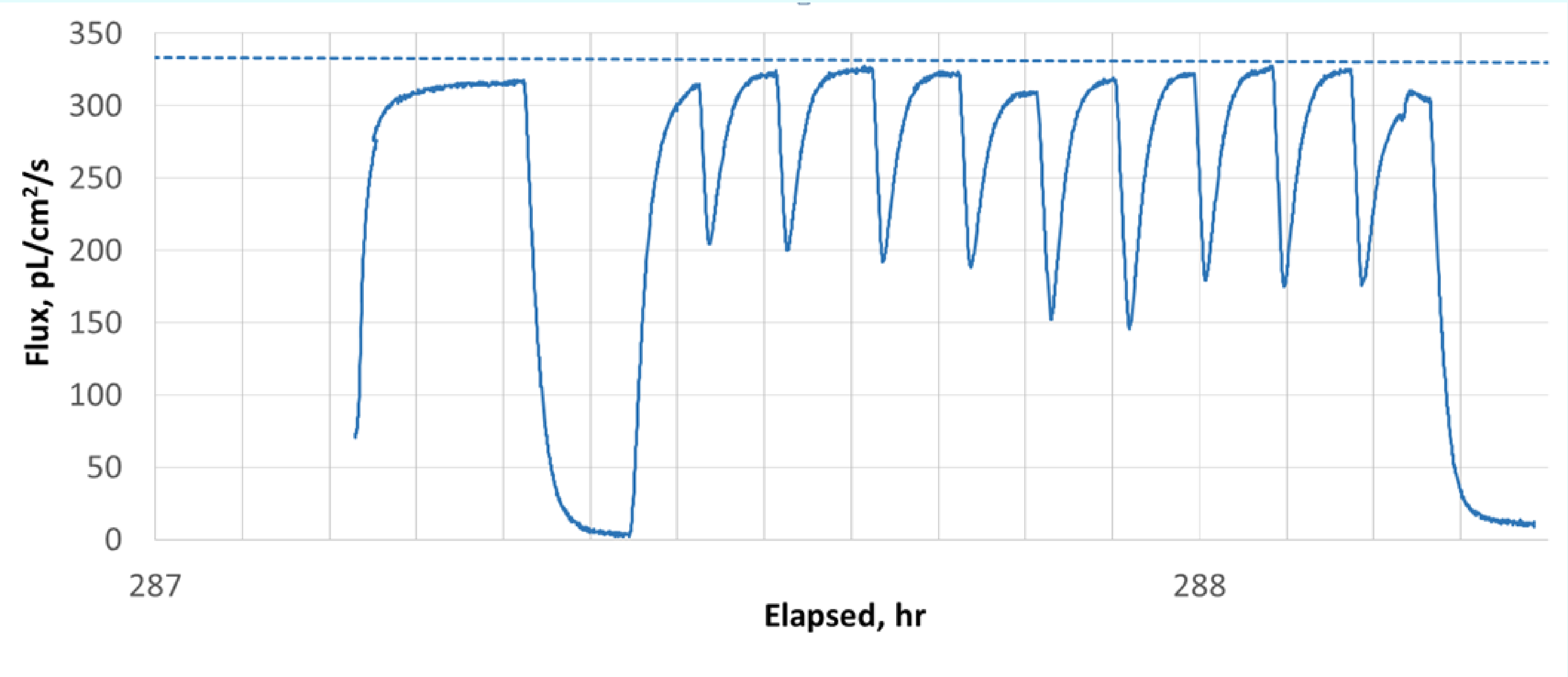
liquid in/out

gas in

gas out

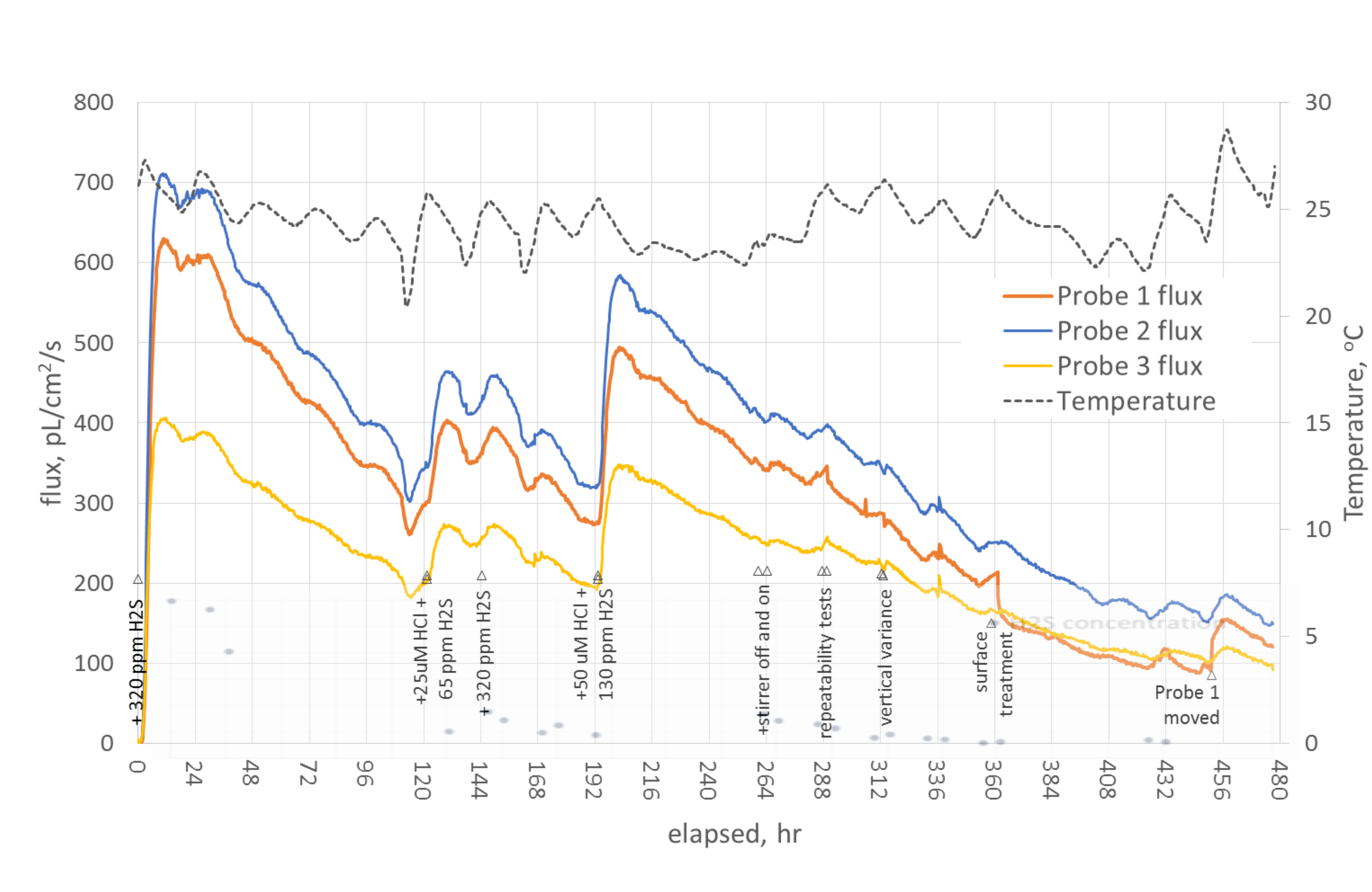
T

Repeatability on probe detachment at single site



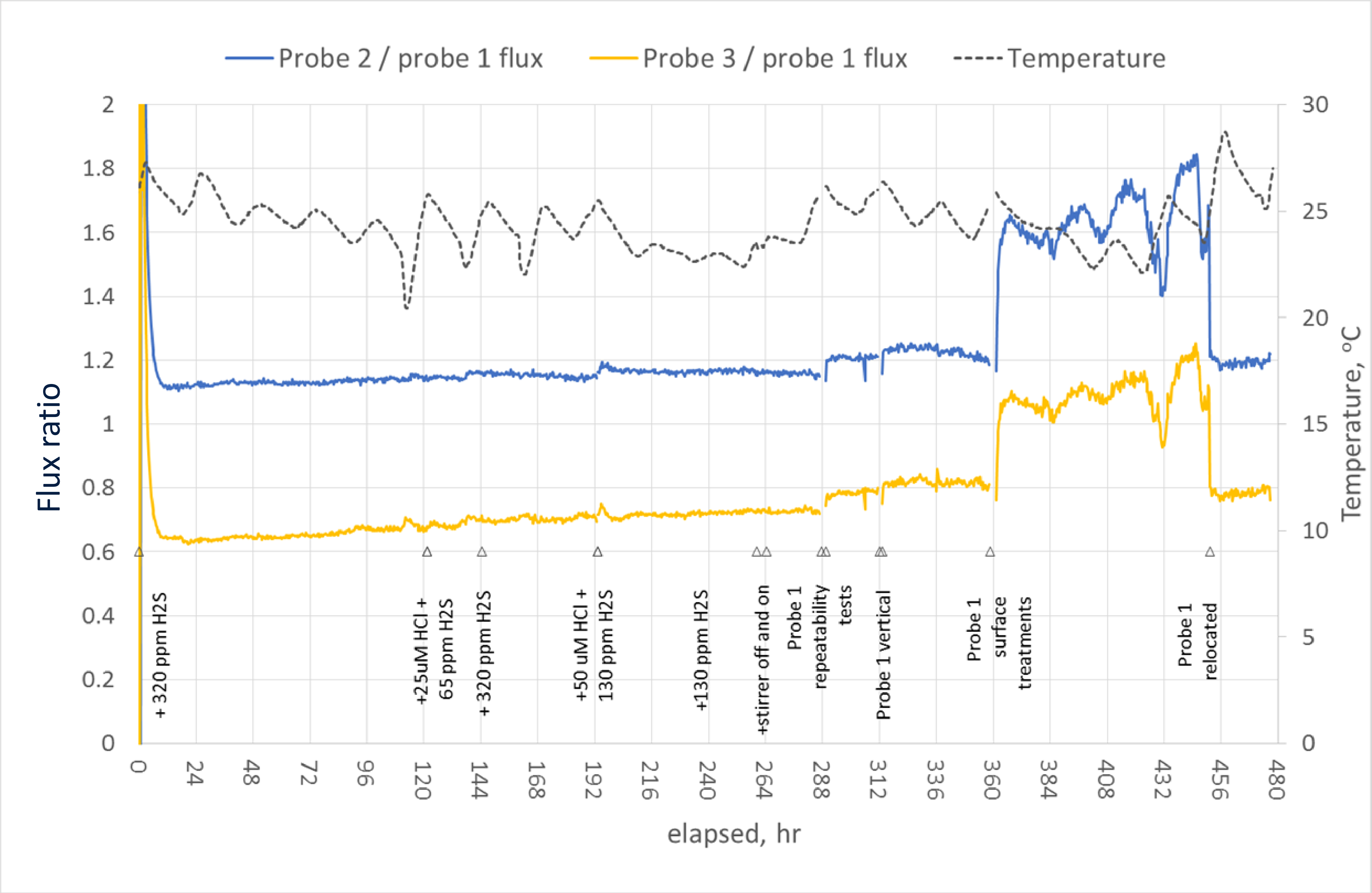
Co-trending of flux (1)

F.W.H.Dean, A.Witty, A.Zanre, *Corrosion 2017*, Paper 9694, Conference Series, NACE, Houston 2017.



Automated monitoring of flux at multiple points would ensure more accurate and assured realisation of corrosion severity and save time.

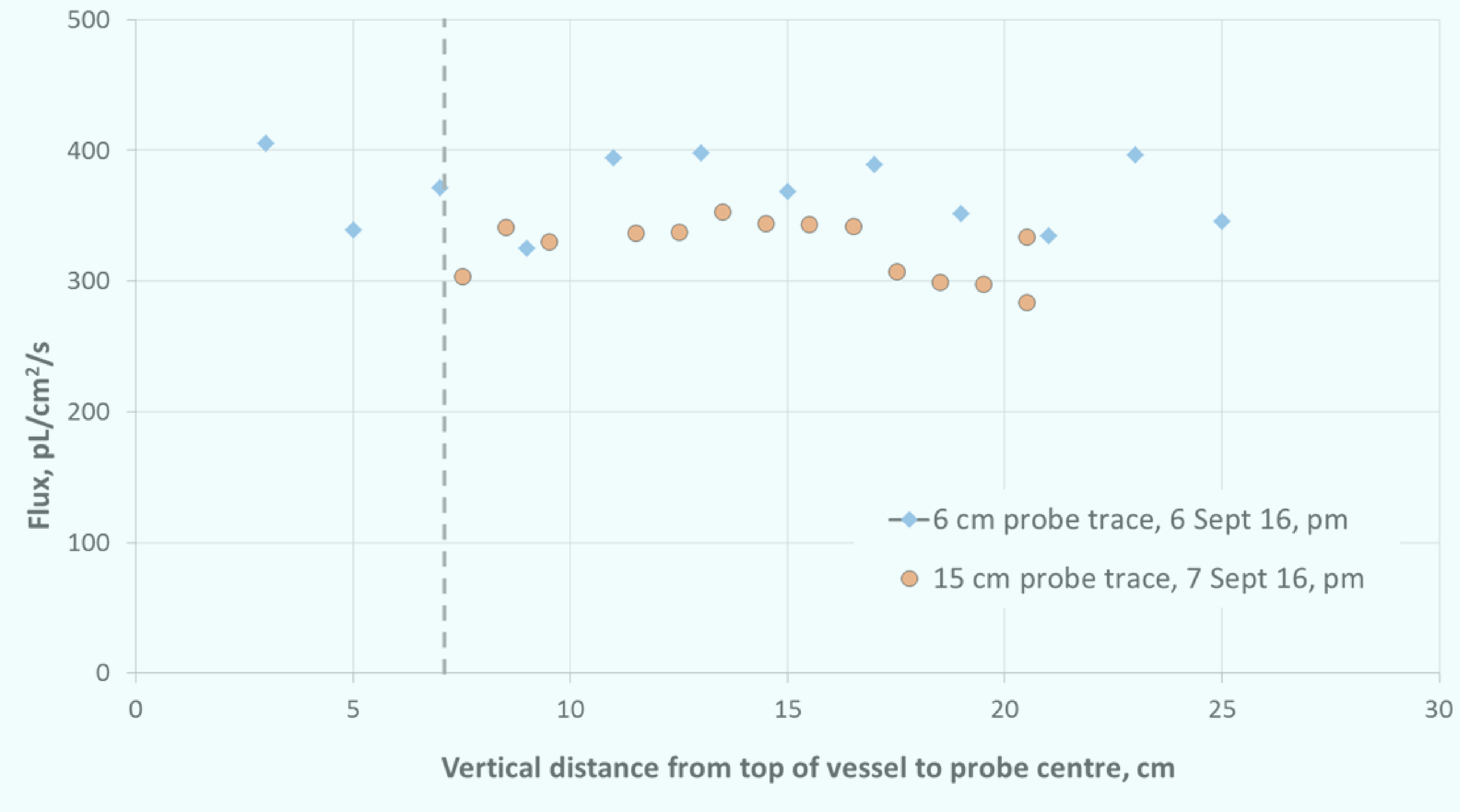
Co-trending of flux (2)



Automated monitoring of flux at multiple points would ensure more accurate and assured realisation of corrosion severity and save time.

F.W.H.Dean, A.Witty, A.Zanre, *Corrosion 2017*, Paper 9694, Conference Series, NACE, Houston 2017.

Multipoint spot measurements (vertical profile)

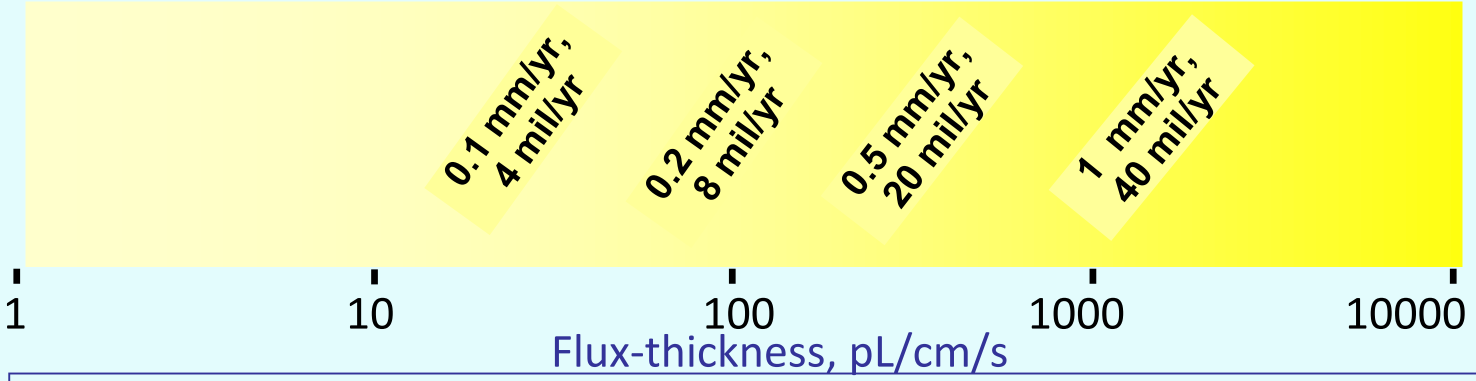


Flux was not subject to vertical variance, even at the liquid level

Data interpretation

Sour corrosion

In assessing sour corrosion, flux measurements are most reliable where corrosion is contingent on removal of corrosive scale. Such corrosion occurs in distillation units, overhead, eg in condensers, fin-fan units, coolers and sour flare lines. It can be very severe (>500 pL/cm^2/s) and is often associated with hydrogen damage (see separate slide). It is usually episodic, occurring typically after equipment installation, inspection, or sometimes during process changes (eg air ingress, water washes, pH changes). Typically, >5 pL/cm^2/s indicates some corrosion activity, and 100 pL/cm^2/s moderate corrosion. The chart below may also be used to assess corrosion under deposits, eg in amine units.
Please contact Ion Science for further details.



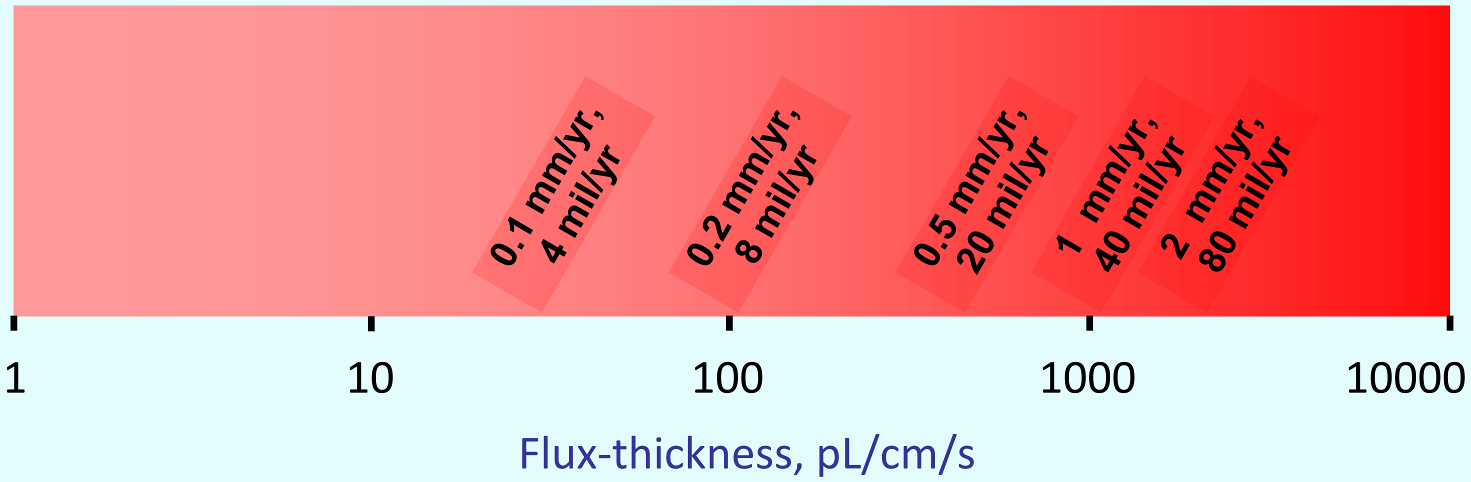
Insructions: Multiply flux in pL/cm^2/s by test site thickness in cm, to obtain a flux-thickness in pL/cm/s. Look along bottom of chart for corrosion rate. Note corrosion flux correlation varies in a complex way with other corrosion variables, not least temperature. This makes the correlation very approximate.

eg, flux = 20 pL/cm^2/s, thickness = ½ in = 1.25 cm => flux-thickness = 25 pL/cm/s. Corrosion rate is *very* approximately 0.2 mm/yr, 8 mil/yr.

Data interpretation

HF acid corrosion

5 pL/cm^2/s indicates very low but definite HF corrosion. 300-500 pL/cm^2/s is common,. HF is used to catalyse the formation of high octane gasoline – alkylate – from smaller olefins in HF alkylation units. The alternative catalyst – sulfuric acid – also causes corrosion but provides a much weaker flux signal. HF corrosion is very widespread and continuous. There is probably some temperature dependency for corrosion-flux correlation not shown on the chart.



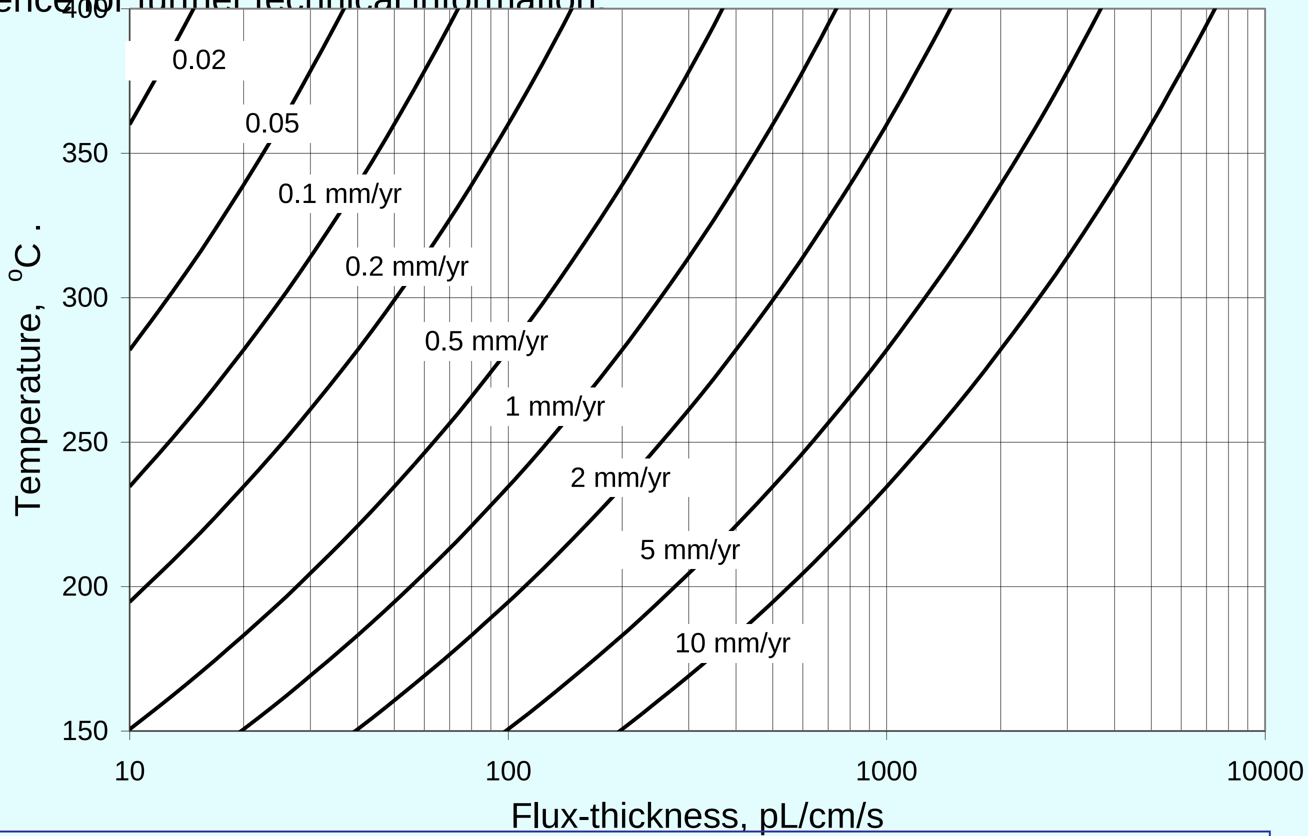
Instructions: Multiply flux in pL/cm^2/s by test site thickness in cm, to obtain a flux-thickness in pL/cm/s. Locate this value on the x-axis and corresponding *approximate* corrosion rate.

eg, flux = 200 pL/cm^2/s, thickness = 2 cm   => flux-thickness = 400 pL/cm/s. Corrosion rate is *approximately* 0.5 mm/yr, 8 mils/yr.

Data interpretation

Naphthenic acid and sulfidic corrosion

A few 10's of pL/cm²/s indicate active corrosion. A few thousand pL/cm²/s have been registered in very acid corrosive streams. 'Naphthenic acid' is in fact a large family of acids found in crude oil. Corrosion generally occurs at pipe bends and reducer sections. The correlation below is based on lab experiments and some field data. The chart is also applicable to other acidic corrodants above about 150 °C, 300 °F. Please contact Ion Science for further technical information.

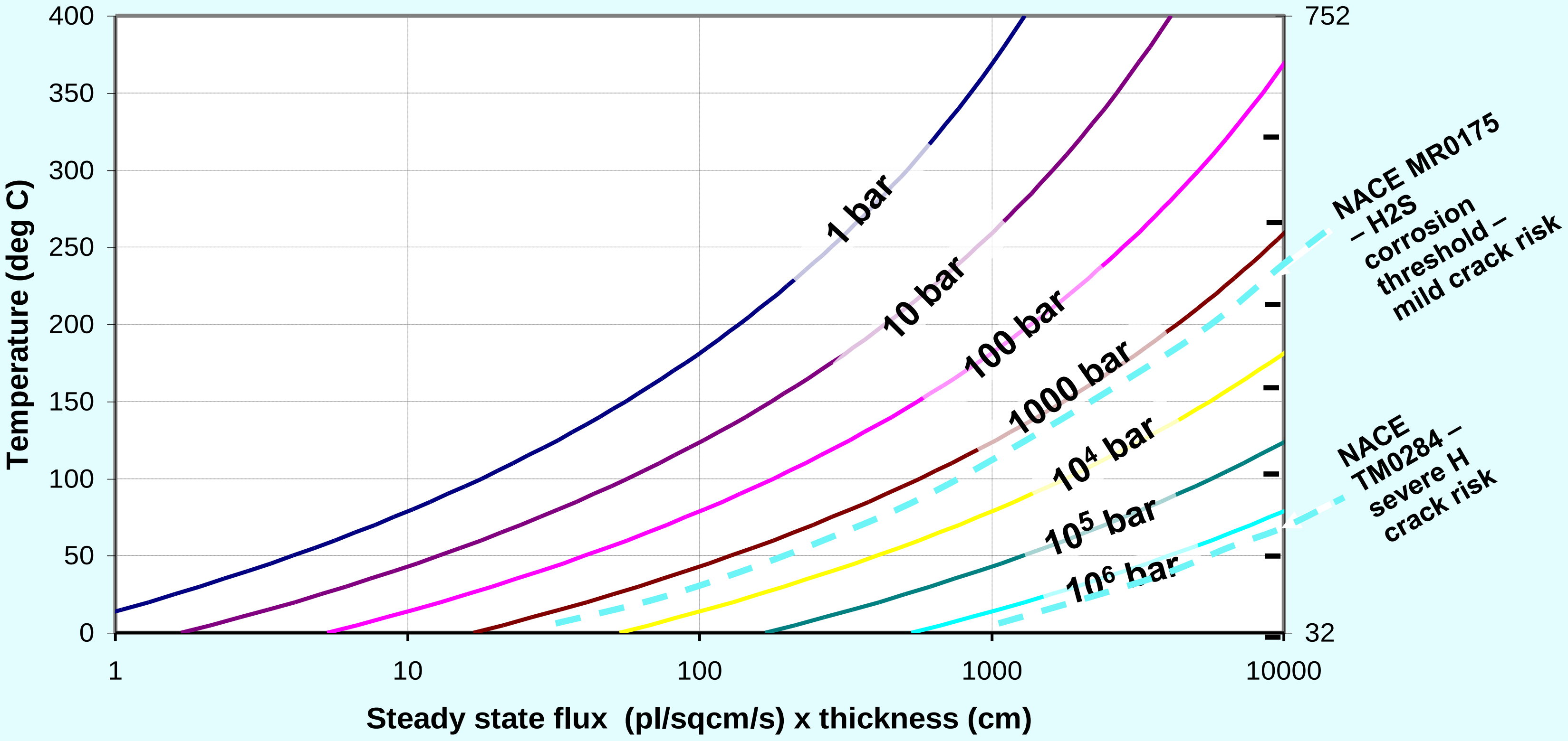


Instructions: Multiply flux by test site thickness in cm to obtain a flux-thickness. Locate this value on the x-axis. Look up temperature on the y-axis. The corrosion rate through mild steel is demarcated between lines.

Data interpretation

Hydrogen cracking

Generally, hydrogen cracks are initiatied in poor quality, non-sour service steels, and welds, at activities as low as 10000 bar, whereas sour service steels can withstand at least 1,000,000 bar. After cracks have appeared, much lower activities are needed to propagate them, indeed, any flux may contribute to further crack growth.



Instructions: Using the hydrogen activity expressed in bar obtained in step 1. See S.Al-Sulaiman, A.Al-Mithin, A.Al-Shamari, M.Islam, S.S.Prakash, 'Assessing the possibility of hydrogen damage in crude oil processing equipment', Corrosion 2010, Paper 10176, Conference series, NACE, Houston, 2010 .

Conclusions

A new Hydrosteel analyser is introduced:

- More robust probes
- Extended monitoring capability
- Multiple point monitoring

Please contact

Frank.Dean@ionscience.com

If interested.

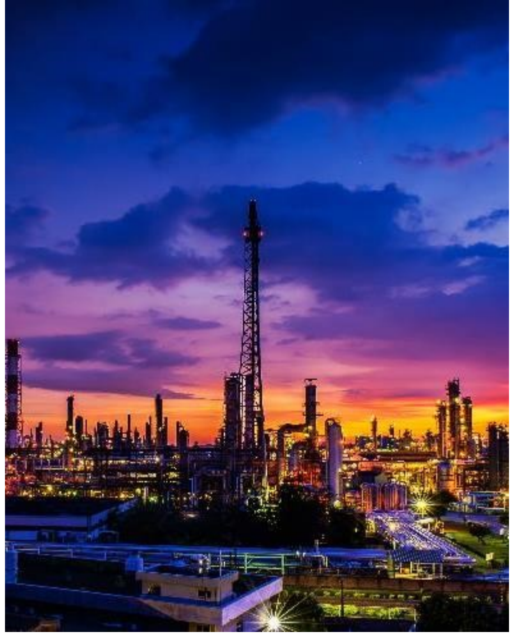
Thank you for your attention

Appendix 11

"Corrosion Software Sensor" – A New Framework to utilize the power of process data and prediction tools

(Slawomir Kus)




“CORROSION SOFTWARE SENSOR” A NEW FRAMEWORK TO UTILIZE THE POWER OF PROCESS DATA AND PREDICTION MODELS

Honeywell

AGENDA

“Software sensor”

- General concept
- Structure, Requirements, Scalability

Application case study (EU Refinery)

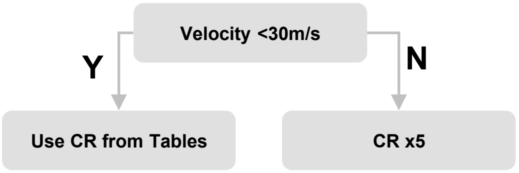
- General information
- Implementation approach
- Outcomes

Summary & Discussion

FROM "STATIC" TO "REAL-TIME" CORROSION QUANTIFICATION – HISTORICAL VIEW

70-80s XX
API RP581, 932B

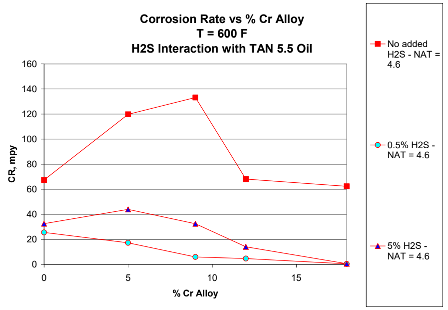
- "Consensus"
- Arbitrary correction factors
- In several areas found misleading about expected corrosion rate (NH_4HS, sulfidic/Nap acid)

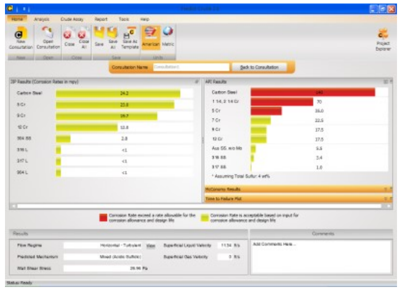


Sulfur (wt%)	TAN (mg/g)	Temperature (°C) ≤232	260	288	315	343
0.2	4.0	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.03
	6.0	0.03	0.03	0.03	0.05	0.10

90s XX
"Static" software models

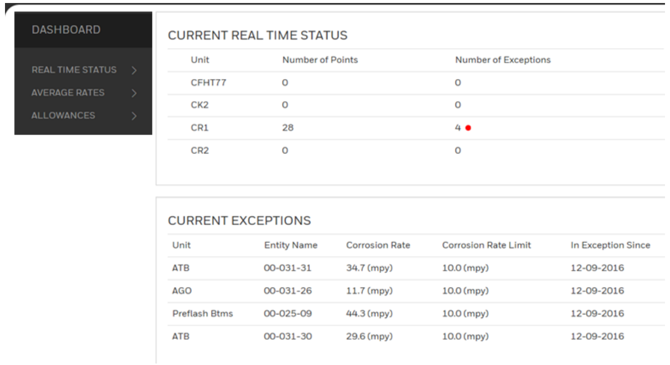
- Based on extensive studies on specific corrosion mechanisms
- Utilizing modern IT systems to generate multiparametric corrosion modelling framework
- Field-proven





XXI
Prediction in real time

- Combining "static" models and "live" data streams from Process Historian
- Automated predictions are following process changes
- High level analytics with "live" Corrosion/Inspection KPI's



CURRENT REAL TIME STATUS

Unit	Number of Points	Number of Exceptions
CFHT77	0	0
CK2	0	0
CR1	28	4
CR2	0	0

CURRENT EXCEPTIONS

Unit	Entity Name	Corrosion Rate	Corrosion Rate Limit	In Exception Since
ATB	00-031-31	34.7 (mpy)	10.0 (mpy)	12-09-2016
AGO	00-031-26	11.7 (mpy)	10.0 (mpy)	12-09-2016
Preflash Btms	00-025-09	44.3 (mpy)	10.0 (mpy)	12-09-2016
ATB	00-031-30	29.6 (mpy)	10.0 (mpy)	12-09-2016

"SOFTWARE SENSOR" CONCEPT

SOFTWARE AS A *CORROSION SENSOR* – CONCEPT

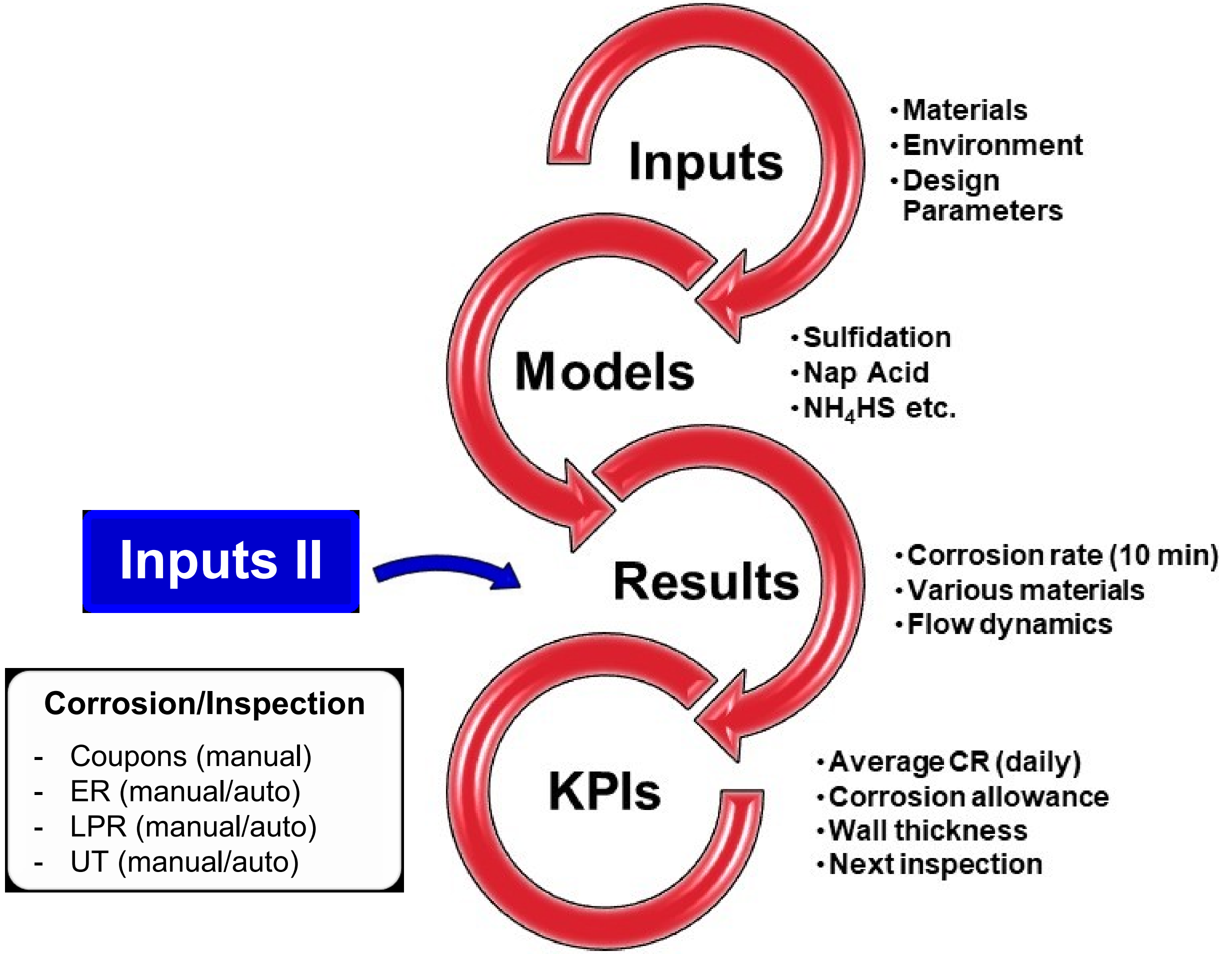
"Software corrosion sensor" is a *scalable* and *adaptive* IT framework designed to glean process driven corrosion insights and provide process-corrosion relations in *real time*.

The software sensor platform utilizes "live" process data streams available in the Historian and proven corrosion models to deliver quantified corrosion info:

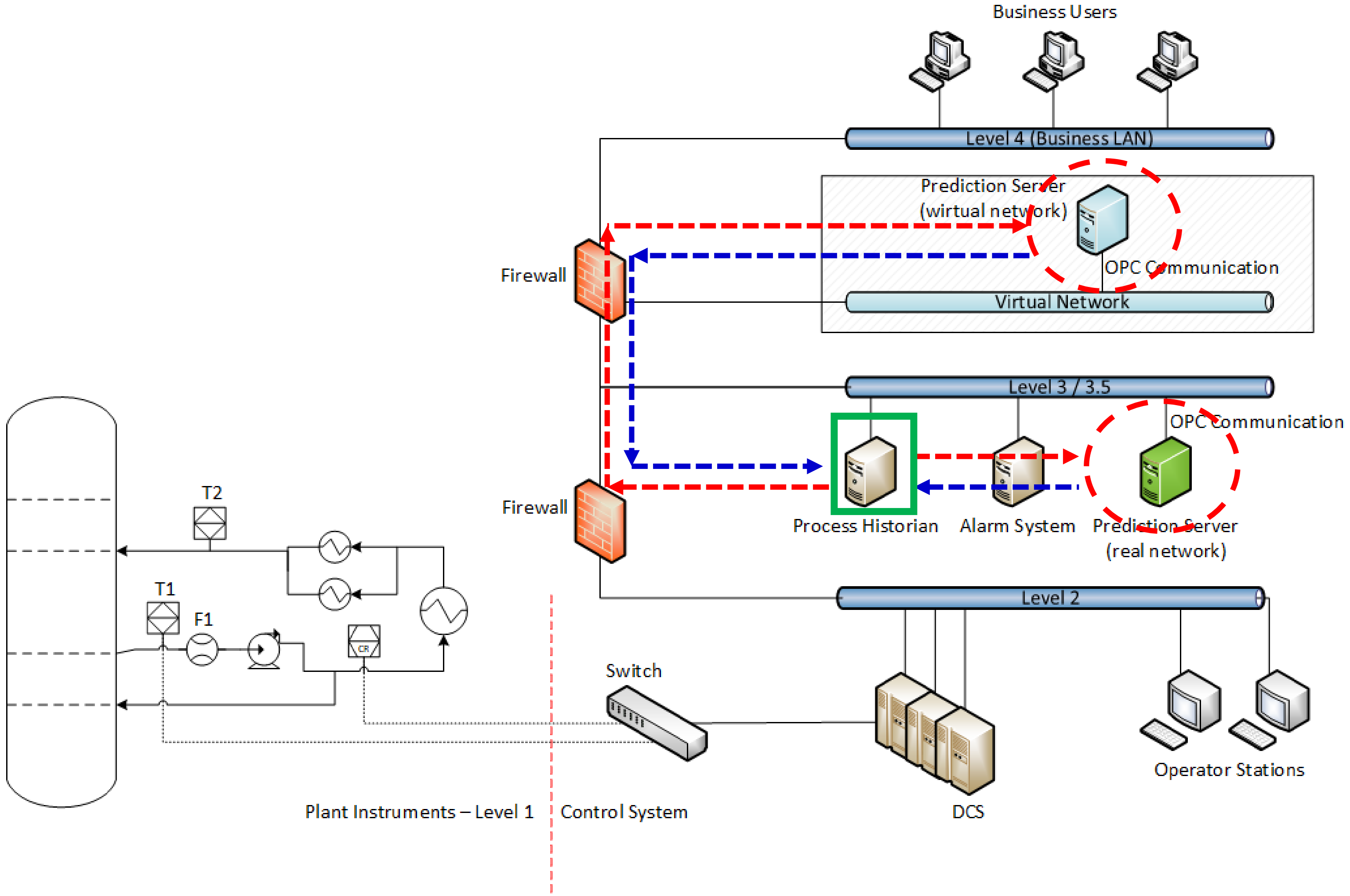
- corrosion rate
- flow parameters (WSS, flow pattern)

Software sensor can also provide:

- real time KPI's
- real time integrity overview



HOW DOES IT WORK?



- Real or virtual server
- Network Level (3.5 or 4)
- Security and user access
- OPC connectivity
  - DA (data access)
  - HDA (historic data access)

WHAT INFORMATION IS NEEDED?

Process

- Process Flow Diagrams
- Process and Instrumentation Diagrams (P&IDs)
- Operating Conditions
- Best Instruments/Measurements representing circuits conditions
- Sampling points for Lab analyses

Control/Instrumentation/Systems

- Tags for Instruments/Measurements
- Tags for Lab data
- Tags for results (if needed)
- Calculated Tags
  - If flow estimates are needed
  - If Eng. Unit conversions are needed

Inspection/Corrosion

- Corrosion Loops (Corrosion Control Documents)
- Piping Circuits
- Inspections, Thickness Monitoring Locations (TML) and Thickness data
- Piping Isometrics, Materials, Diameters, Initial/Design Thicknesses
- Sampling points for Lab analyses
- Corrosion Failure History

IT/Systems

- OPC Connectivity
- User & Admin access/permissions
- Backups & Maintenance
- Network Architecture

TIMING AND RESOURCES

Next Replacement Date	Design Wall Thickness	Last Known Wall Thickness
15/10/2025	9.52	9.52
15/10/2025	9.52	9.52
15/10/2025	9.52	9.52
15/10/2025	9.52	9.52
15/10/2025	9.52	9.52
16/10/2025	9.52	9.52
16/10/2025	9.52	9.52
22/08/2022	12.70	12.7
22/08/2022	12.70	12.7
22/08/2022	12.70	12.7
22/08/2022	6.02	6.02
22/08/2022	12.70	12.7
22/08/2022	12.70	12.7
22/08/2022	7.11	7.11
22/08/2022	9.27	9.27

Services:

- “static” modelling
- Configuration table

Data

Hardware/ software
Windows 2012 R2; SQL Server 2012 R2
SQL Server Reporting Services; IIS (Web Server);
OPC server license
Processor: Two Quad Processors, 3GHz, 64-bit (x64)
RAM: 16 gigabytes (GB)
Hard disk drive: 500GB

Typical timing: 1-3 months
(start-commissioning) / based on unit size and complexity

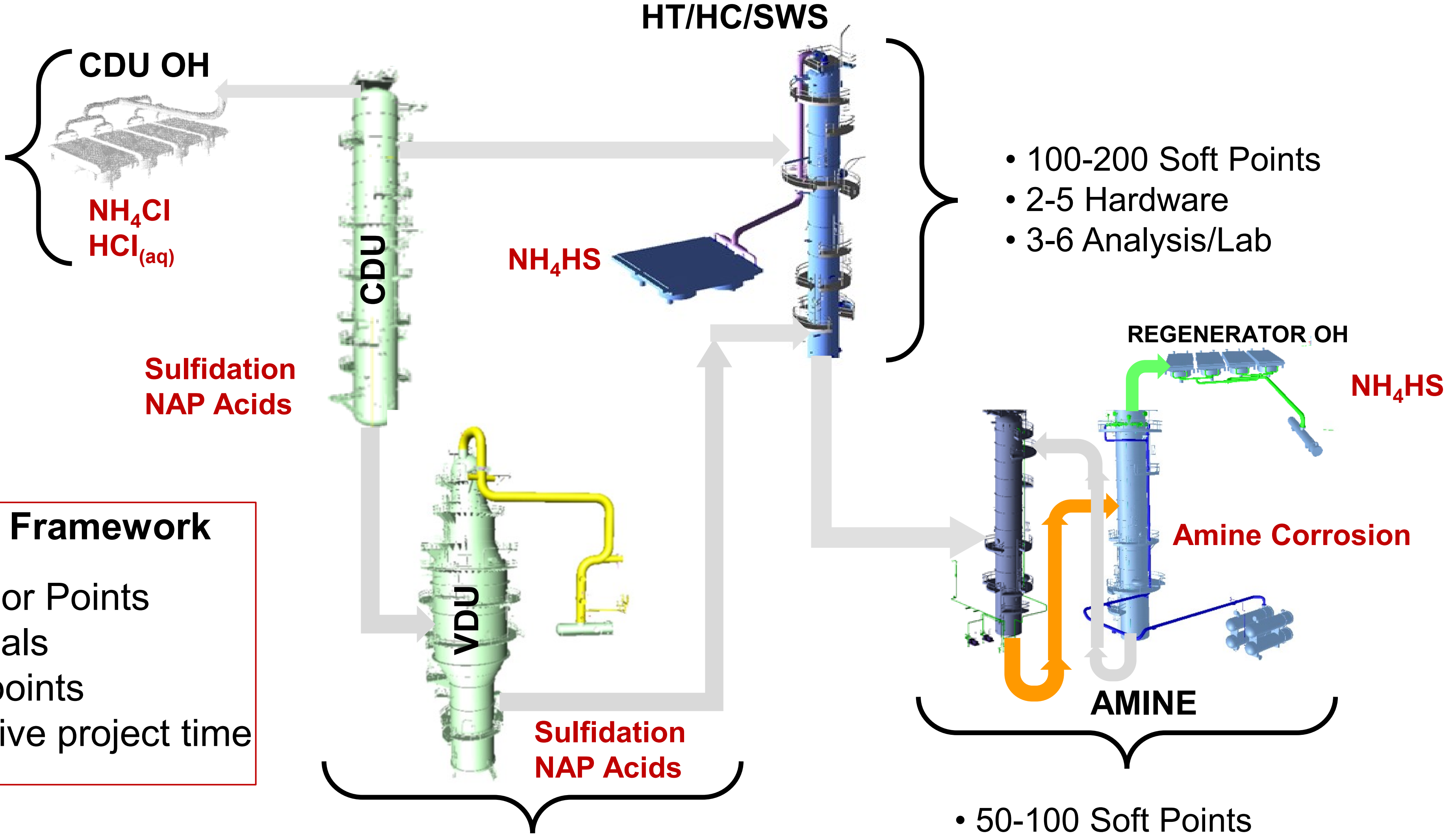
Start

Typical refinery manpower required:
2 engineers for 1-2 weeks
(corrosion/process & IT)

Software Sensor Commissioning

SCALABILITY

- 50-100 Soft Points
- 3-6 Hardware
- 2-6 Analysis/Lab



- 100-200 Soft Points
- 2-5 Hardware
- 3-6 Analysis/Lab

Refinery Corrosion Framework

- 300-600 Soft-Sensor Points
- x number of materials
- c.a. 20 Hardware points
- 6-10 months effective project time

- 100- 200 Soft Points
- 2-5 Hardware
- 1-3 Analysis/Lab

- 50-100 Soft Points
- 4-8 Hardware
- 3-6 Analysis/Lab

LEGEND:
Sulfidation – available models

SOFTWARE SENSOR IMPLEMENTATION – CASE STUDY

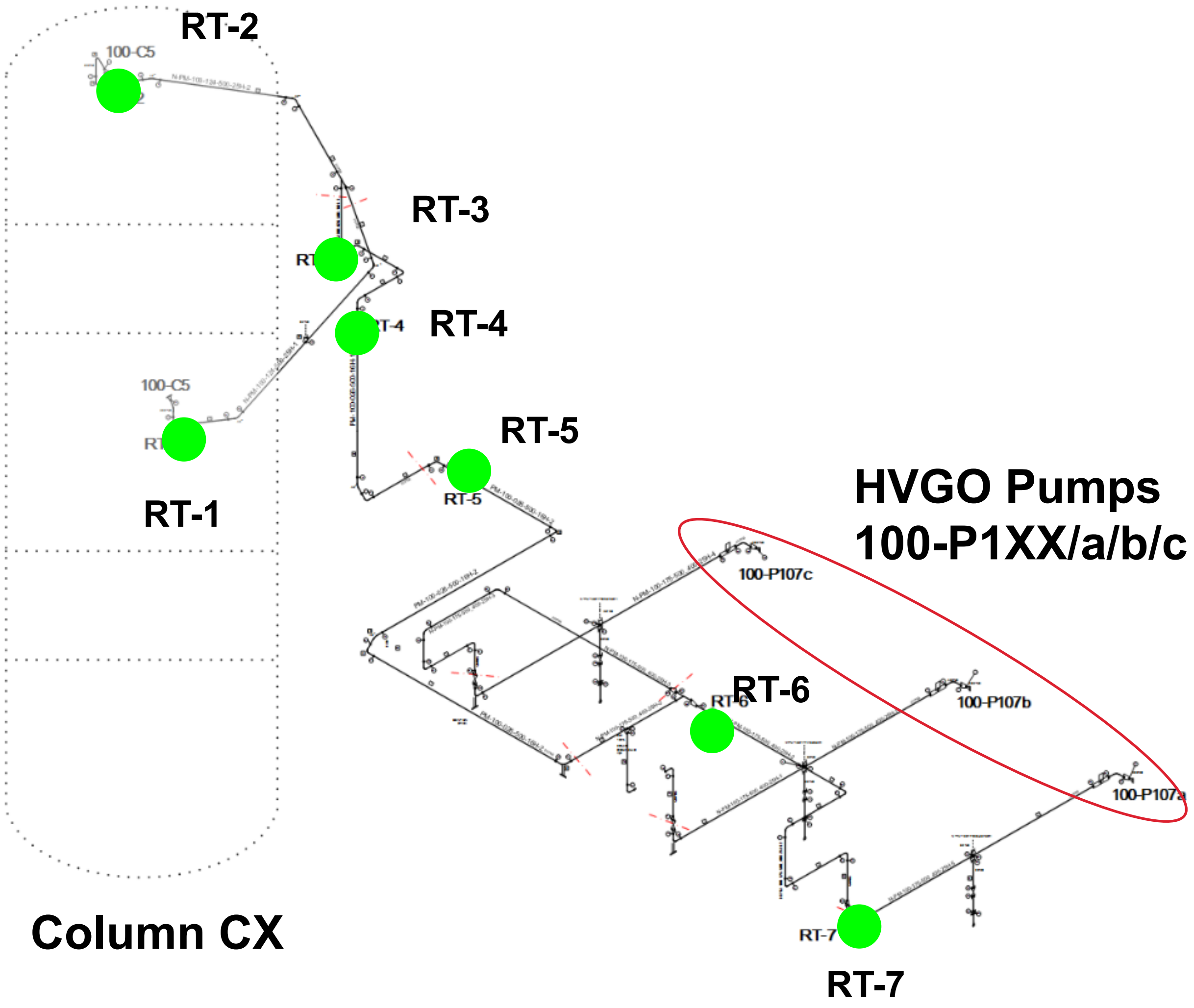
Goals:

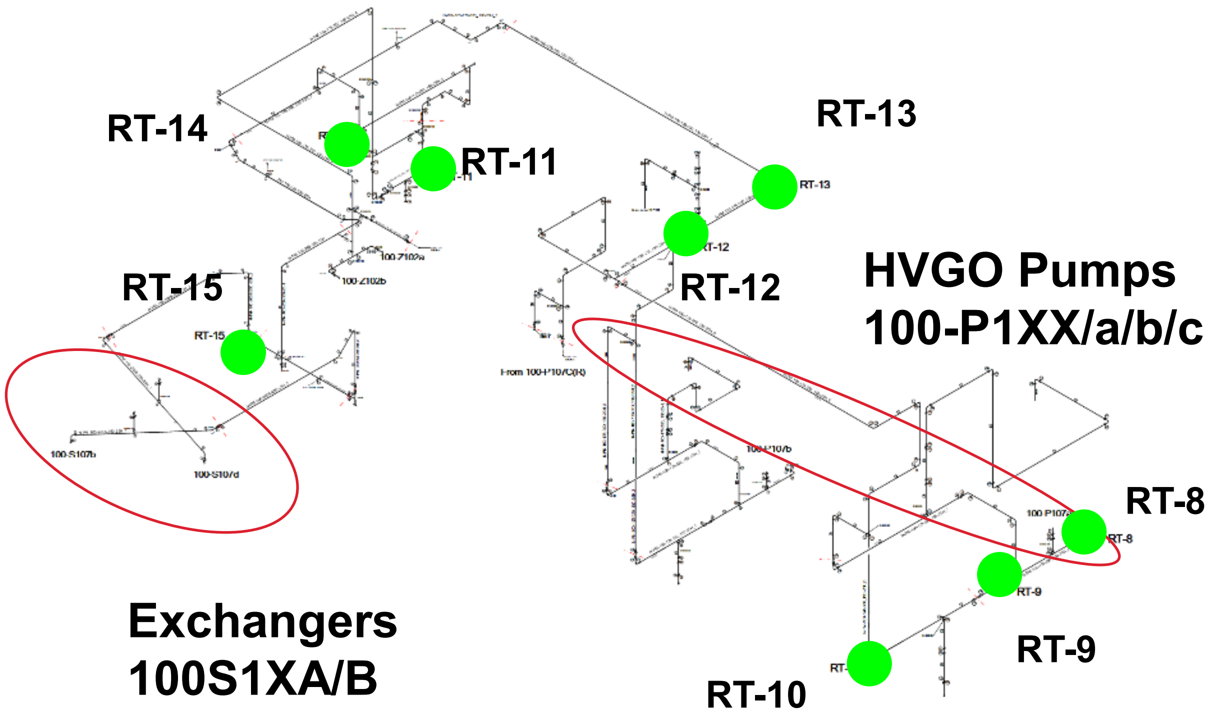
- ➢ Deliver a process-integrated solution for real time, quantified corrosion rates and process correlations in HVGO line.
- ➢ Show utilization of *Corrosion* as a process variable (PV) and present potential for real-time corrosion management purposes in CDU/VDU

Details:

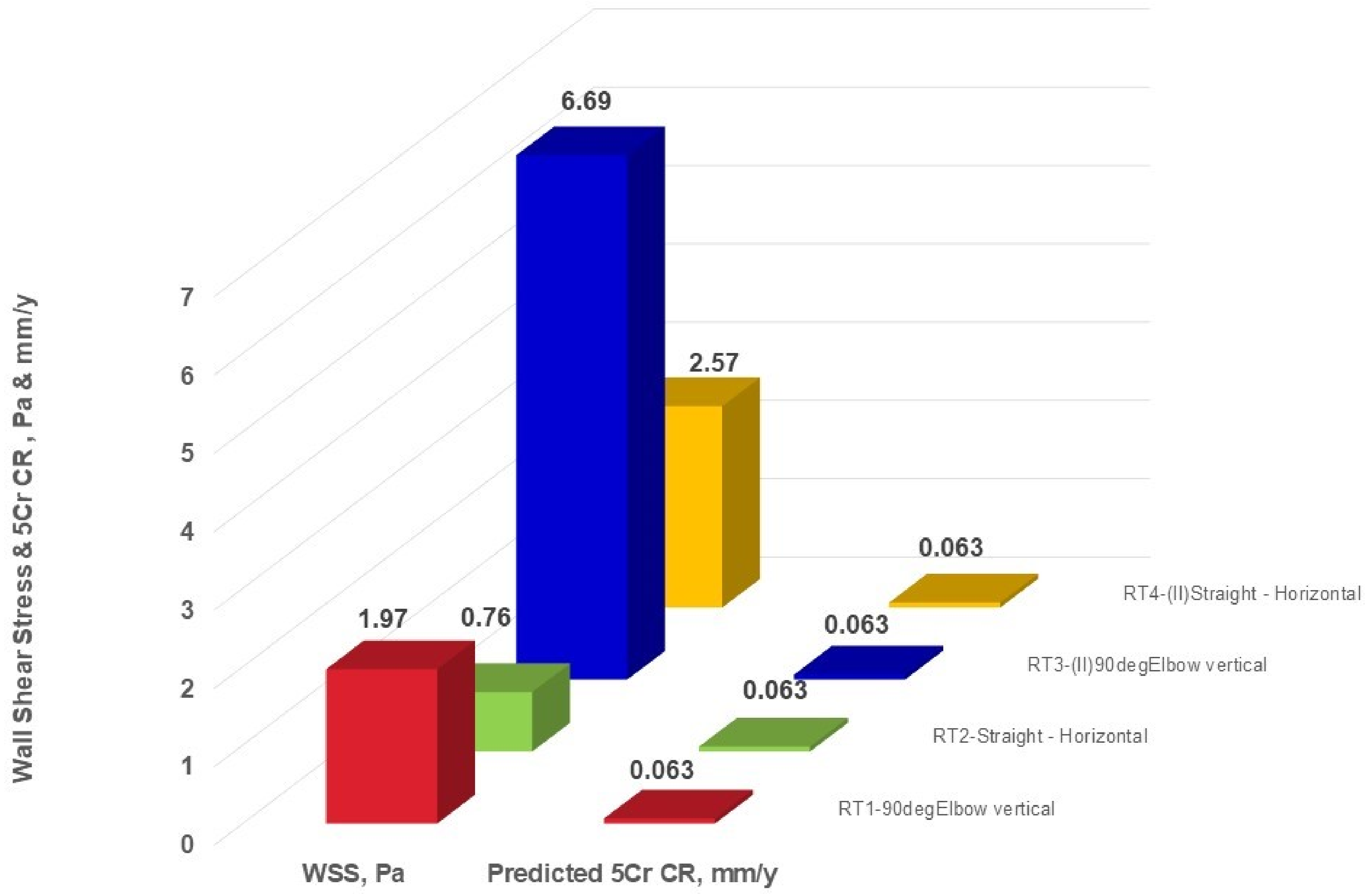
- Location: EU Refinery
- HVGO Line
- 5Cr material
- 15 modelling points – 45 Tags in Historian
  - Pipe MoC Corrosion rate per JIP – 15 Tags (update every 10min)
  - 1-D Average MoC Corrosion Rate – 15 Tags (daily update)
  - Predicted Wall Thickness – 15 Tags (daily update)
- +200 tags saved in Prediction Server
- Historian – OSI/PI
- Prediction Model – Predict Crude

TASK 1 - SELECTION OF MODELLING POINTS – HVGO (EXAMPLE)

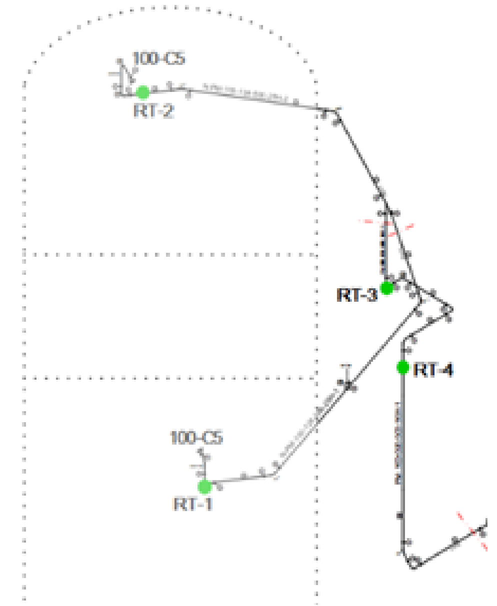




TASK 1.1 - "OFFLINE" MODELLING TO CONFIRM HOT SPOTS



Measured parameter	DCS Tag	from DCS	Unit
Temp in CX near outlet of HVGO	100-TI-0xxx-23	269	degC
HVGO Hot circulation flow	100-FIC-00x6	59	m3/h
HVGO PA flow	100-FIC-00x6	515	m3/h
HVGO return temp (measured in CX)	100-TI0115-xx	248	degC

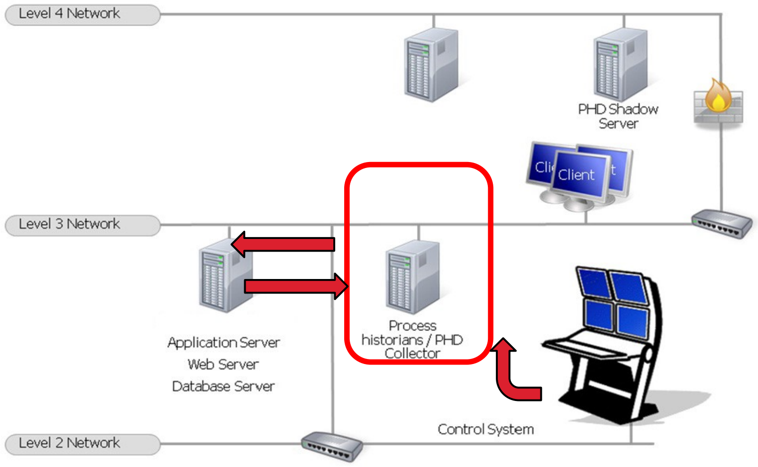


TASK 2&3 – IMPLEMENTATION & SUPPORT

Task 2: Software Implementation

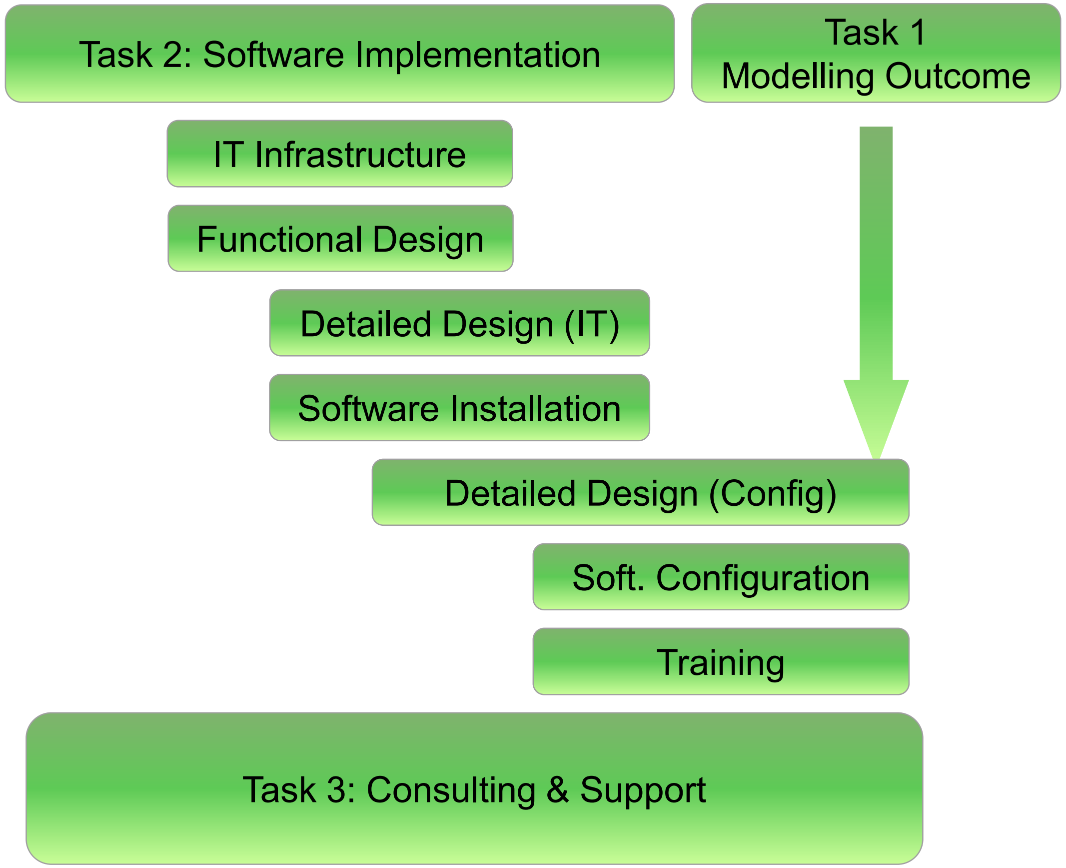
Task 1
Modelling Outcome

- IT Infrastructure
- Functional Design
- Detailed Design (IT)
- Software Installation
- Detailed Design (Config)

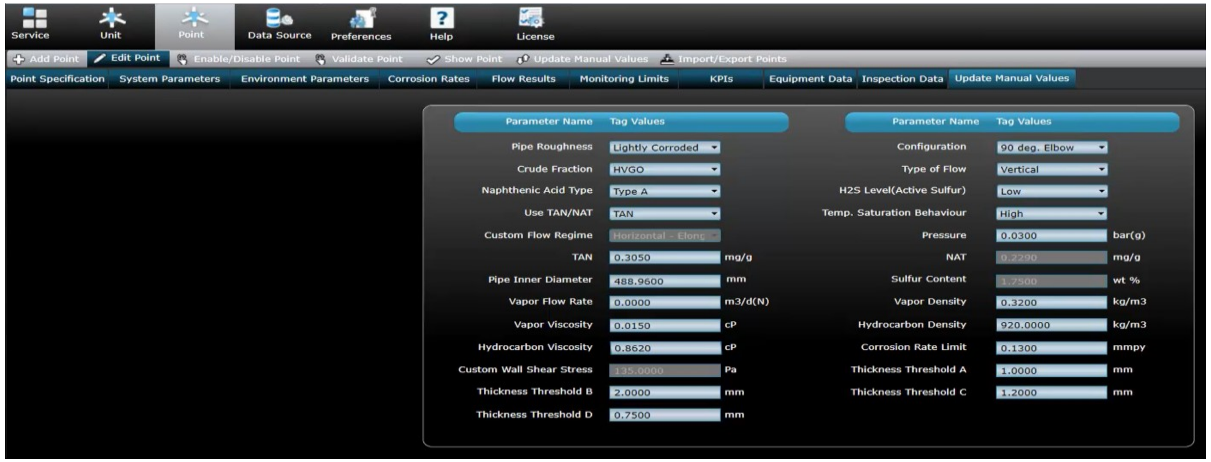


Point	Description	Unit Name	Enable?	Location
100P107aRT9	Outlet from 100-P107a - horizontal straight	178-350_150-25H	☑	178-350_150-25H_7-193
100C5VDURT2	Outlet C5-StraightHorizontal	124-500-25H	☑	124-500-25H_2-3
100P107abcRT12	Common outlet HVGO pumps - horizontal straigl	178-350_150-25H	☑	178-350_150-25H_2-54
100C5VDURT3	Common outlet C5-ElbowVertical	026-500-16H	☑	026-500-16H_1-1
100P107aRT10	Outlet from 100-P107a - vertical elbow	178-350_150-25H	☑	178-350_150-25H_6-184
100P107aRT6	Inlet to P107a-StraightHorizontal	175-500_400-25H	☑	175-500_400-25H_5-57
100Z102abRT11	Inlet to filters 100-Z102a(b) - vertical elbow DN	178-350_150-25H	☑	178-350_150-25H_4-100
100C5VDURT4	Common outlet C5-StraightVertical	026-500-16H	☑	026-500-16H_1-7
100S107dRT15	Inlet to HEX 100-S107d - vertical elbow	266B-250-25H	☑	266B-250-25H_2-14
100C5VDURT5	Common outlet C5-StraightHorizontal	026-500-16H	☑	026-500-16H_2-12
100P107aRT7	Inlet to P107a-ElbowVertical	175-500_400-25H	☑	175-500_400-25H_2-47
100P107aRT8	Outlet from 100-P107a - horizontal elbow	178-350_150-25H	☑	178-350_150-25H_7-223
100P107abcRT13	Common outlet HVGO pumps - horizontal elbow	178-350_150-25H	☑	178-350_150-25H_2-70
100Z102abRT14	Inlet to filters 100-Z102a(b) - vertical elbow DN	178-350_150-25H	☑	178-350_150-25H_3-85
100C5VDURT1	Outlet C5-Elbow vertical	124-500-25H	☑	124-500-25H_1-17

TASK 2&3 – IMPLEMENTATION & SUPPORT



Information	Prefix	Funct. Ident.	Loop Ident.	Suffix	Example
Carbon Steel JIP Corrosion Rate	XX	CY	YYY	CR.JIP.CS	10CY001.CR.JIP.CS
5 Cr JIP Corrosion Rate	XX	CY	YYY	CR.JIP.5CR	10CY001.CR.JIP.5CR
9 Cr JIP Corrosion Rate	XX	CY	YYY	CR.JIP.9CR	10CY001.CR.JIP.9CR
12 Cr JIP Corrosion Rate	XX	CY	YYY	CR.JIP.12CR	10CY001.CR.JIP.12CR
304 JIP Corrosion Rate	XX	CY	YYY	CR.JIP.304	10CY001.CR.JIP.304
316 JIP Corrosion Rate	XX	CY	YYY	CR.JIP.316	10CY001.CR.JIP.316
317 JIP Corrosion Rate	XX	CY	YYY	CR.JIP.317	10CY001.CR.JIP.317
904 JIP Corrosion Rate	XX	CY	YYY	CR.JIP.904	10CY001.CR.JIP.904



SOFT-SENSOR FRAMEWORK OUTPUT

CURRENT REAL TIME STATUS

Unit	Number of Points	Number of Exceptions
CFHT77	0	0
CK2	0	0
CR1	28	4
CR2	0	0

CURRENT EXCEPTIONS

Unit	Entity Name	Corrosion Rate	Corrosion Rate Limit	In Exception Since
ATB	00-031-31	34.7 (mpy)	10.0 (mpy)	12-09-2016
AGO	00-031-26	11.7 (mpy)	10.0 (mpy)	12-09-2016
Preflash Btms	00-025-09	44.3 (mpy)	10.0 (mpy)	12-09-2016
ATB	00-031-30	29.6 (mpy)	10.0 (mpy)	12-09-2016

Real time corrosion status

.ast nspection	Last Inspection (mm)	Date (TMin)
.0-27-2018	9.52	04-18-2037
.0-27-2018	9.52	04-18-2037
.0-27-2018	9.52	04-17-

Support Inspection Planning

9Cr (mmpy)	12Cr (mmpy)	304 (mmpy)
0.040	0.032	0.026
0.040	0.032	0.026
0.040	0.032	0.026

CR for different MoCs

SOFT-SENSOR FRAMEWORK OUTPUT

Real Time Corrosion Status

DASHBOARD

- REAL TIME STATUS
- AVERAGES RATES
- ALLOWANCES
- THICKNESSES
- INSPECTION PLANNING
- PREDICTIONS
- MODEL INPUTS

CURRENT REAL TIME STATUS

Unit	Number of Prediction Points	Number of Monitored Points	Number of Exceptions
100	15	0	0

CURRENT EXCEPTIONS

Unit	Entity Name	Corrosion Rate	Corrosion Rate Limit	In Exception Since

REAL TIME STATUS (026-500-16H)

Point Name	Description	Corrosion Rate Limit (mmpy)	Corrosion Rate (RT) (mmpy)	Corrosion Rate (1D) (mmpy)	Corrosion Rate (7D) (mmpy)	Corrosion Rate (30D) (mmpy)
100C5VDURT3	Common outlet C5-ElbowVertical	0.130	0.073	0.073	0.074	0.081
100C5VDURT4	Common outlet C5-StraightVertical	0.130	0.073	0.073	0.074	0.081
100C5VDURT5	Common outlet C5-StraightHorizontal	0.130	0.073	0.073	0.074	0.081

SOFT-SENSOR FRAMEWORK OUTPUT

Support Inspection Planning

DASHBOARD

REAL TIME STATUS

AVERAGES RATES

ALLOWANCES

100

C5

026-500-16H

CORROSION ALLOWANCES (026-500-16H)

Point Name	Description	Corrosion Allowance Remaining (%)	Corrosion Allowance Remaining (mm)	Corrosion Allowance Consumed (%)	Corrosion Allowance Consumed (mm)	Corrosion Rate (30D) (mmpy)	Date (TMin)	Next Turnaround Date
100C5VDURT3	Common outlet C5-ElbowVertical	99.8	1.50	0.2	0.00	0.081	04-18-2037	10-15-2025
100C5VDURT4	Common outlet C5-StraightVertical	99.8	1.50	0.2	0.00	0.081	04-18-2037	10-15-2025
100C5VDURT5	Common outlet C5-StraightHorizontal	99.8	1.50	0.2	0.00	0.081	04-17-2037	10-15-2025

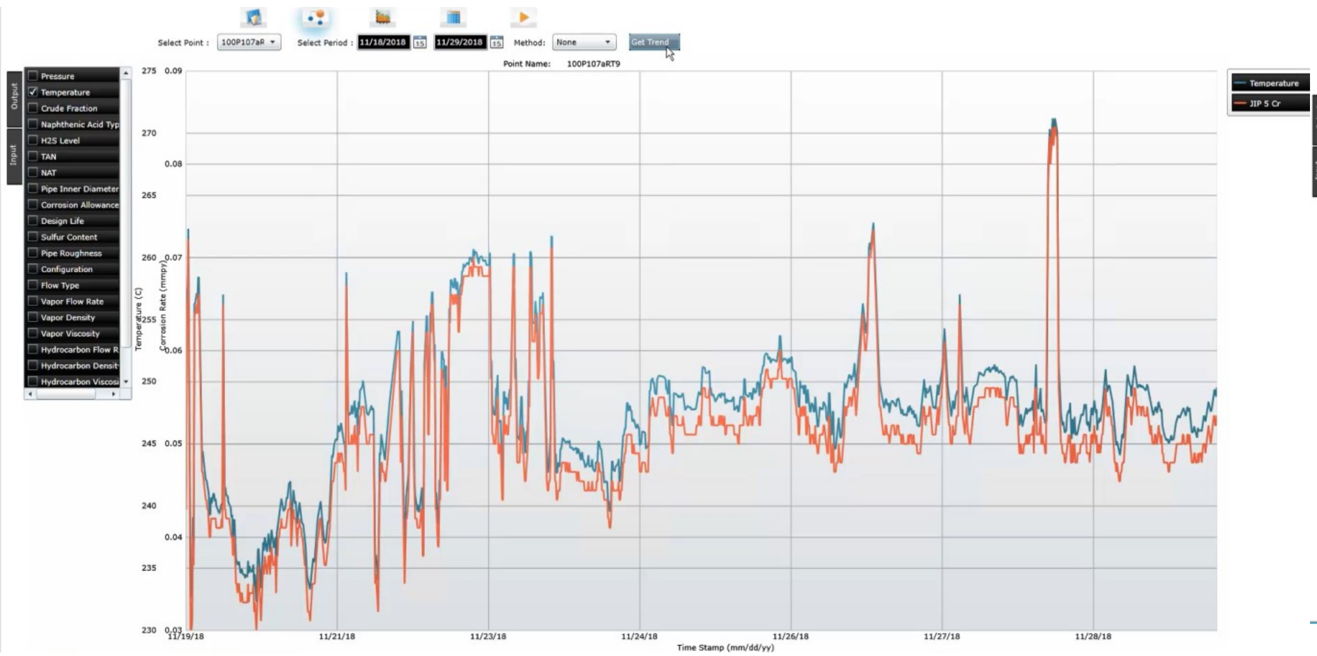
SOFT-SENSOR FRAMEWORK OUTPUT

Corrosion Rates For Various Materials

CORROSION RATE PREDICTIONS (026-500-16H)

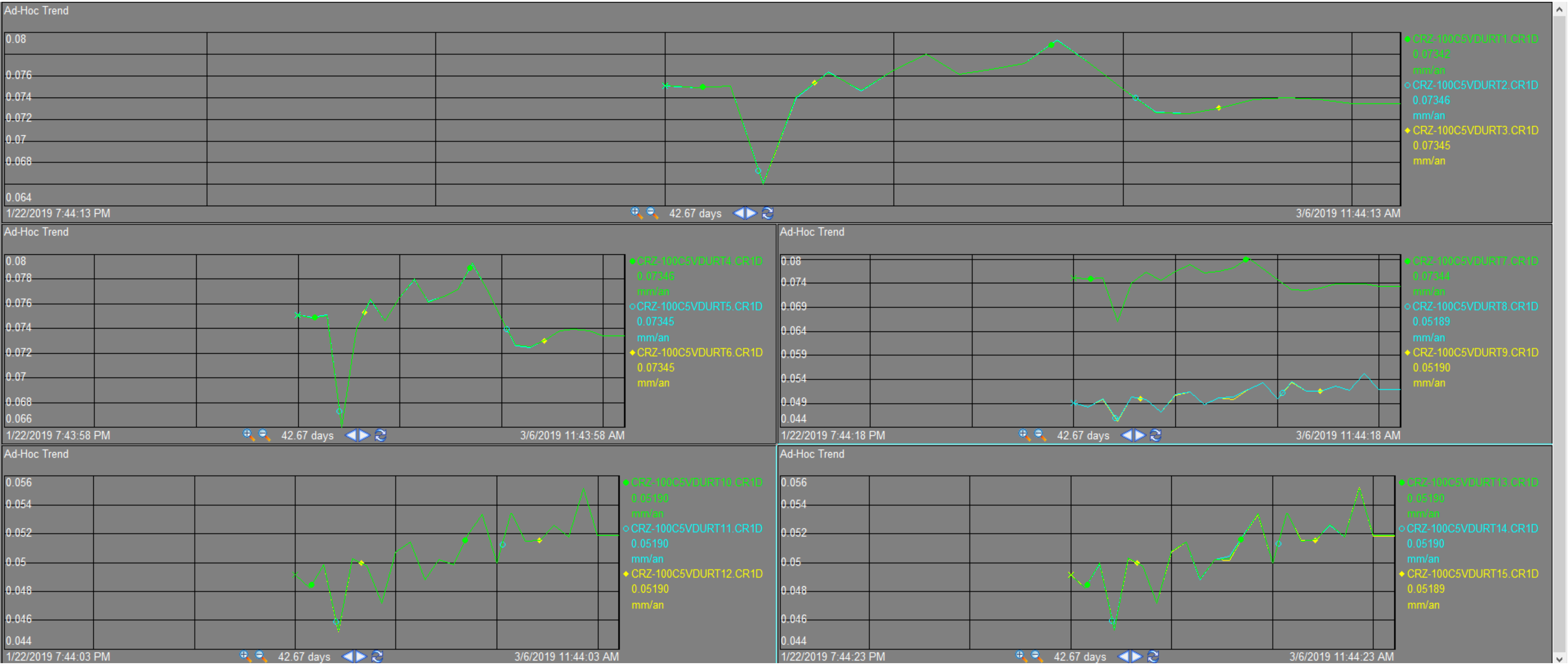
Name	CS (mmpy)	5Cr (mmpy)	9Cr (mmpy)	12Cr (mmpy)	304 (mmpy)	316 (mmpy)	317 (mmpy)	904 (mmpy)
100C5VDURT3	0.120	0.073	0.040	0.032	0.026	0.025	0.025	0.025
100C5VDURT4	0.120	0.073	0.040	0.032	0.026	0.025	0.025	0.025
100C5VDURT5	0.120	0.073	0.040	0.032	0.026	0.025	0.025	0.025

LIVE TRENDING



- **“Live” & historical trending from Real Time Framework level**
- **10min update rate**
- **Process vs Corrosion Rate (predicted and measured – if any available)**

LIVE TRENDING



SUMMARY

- "Software Sensor" concept provides the next generation of predictive insights for real time, intelligent corrosion analysis
- Combines stand alone modelling, "live" process data and corrosion measurements
- Real Time Modelling Framework provides *quantified* insights into corrosion risk and identification of corrosion hot spots in key refinery units
- "Software Sensor" Framework delivers the following features:
  - Real-time Assessment of corrosion "hot-spots"
  - On-line corrosion-process correlations (corrosion as one of PVs)
  - Real-Time Corrosion KPIs
  - High-level overview of Unit/Refinery Integrity status
- Analytical Framework is easily scalable to expand coverage in critical areas in key refinery operating units

Appendix 12

Infra Red Thermography: a reliable, Fast and helpful method in corrosion detection

(Askar Soltani)

Infrared Thermography

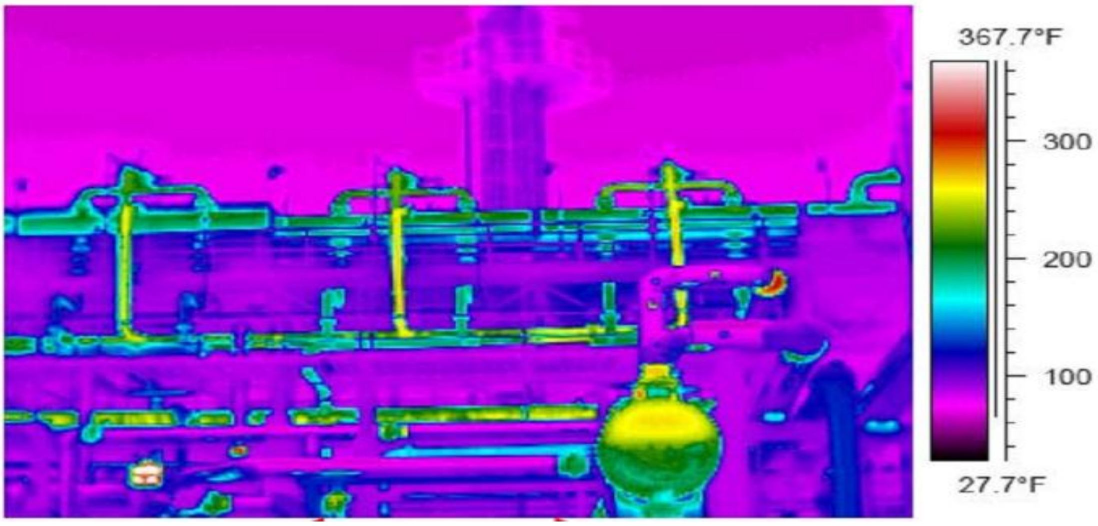
A reliable, Fast and helpful method in corrosion detection

Presented By: Askar Soltani

IR thermography has been applied in different industries as a useful method. Unfortunately in oil and gas industry it is not being applied as a useful instrument to detect corrosion, however it can be used as a helpful instrument beside UT measurements to detect corroded areas or areas in the pipe or vessels which hard scales precipitation is likely to occur. Hereafter some IR thermal images have been indicated which reveals operating problems detected by thermal cameras.

IR scan of inlet piping to three air cooler headers

[Ref.: NACE paper no. 10362]



IR scan at water injection point

[Ref.: NACE paper no. 10362]

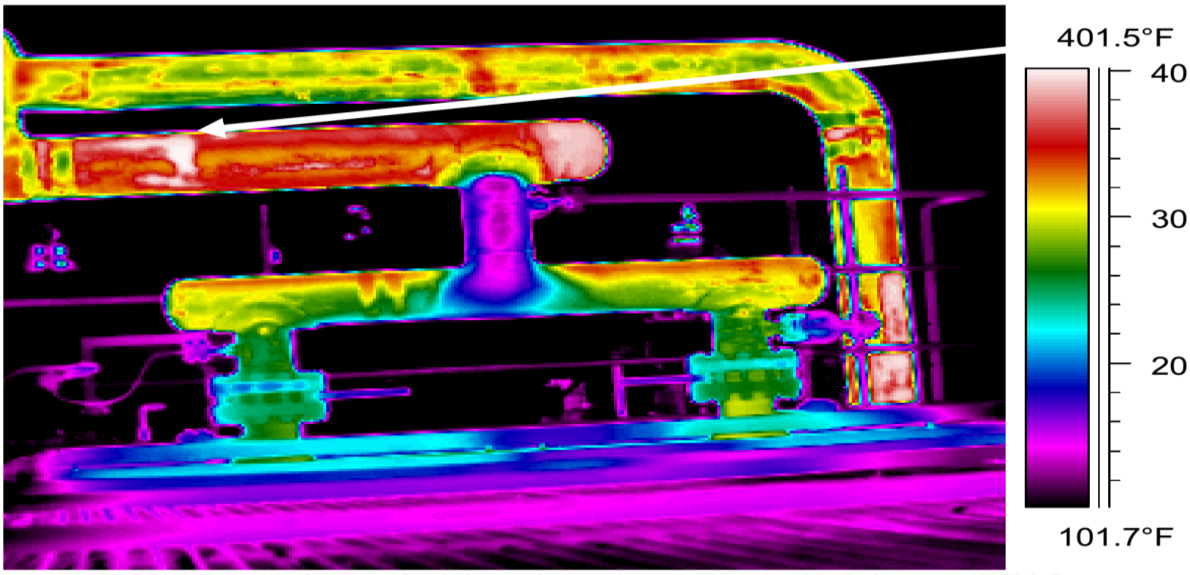
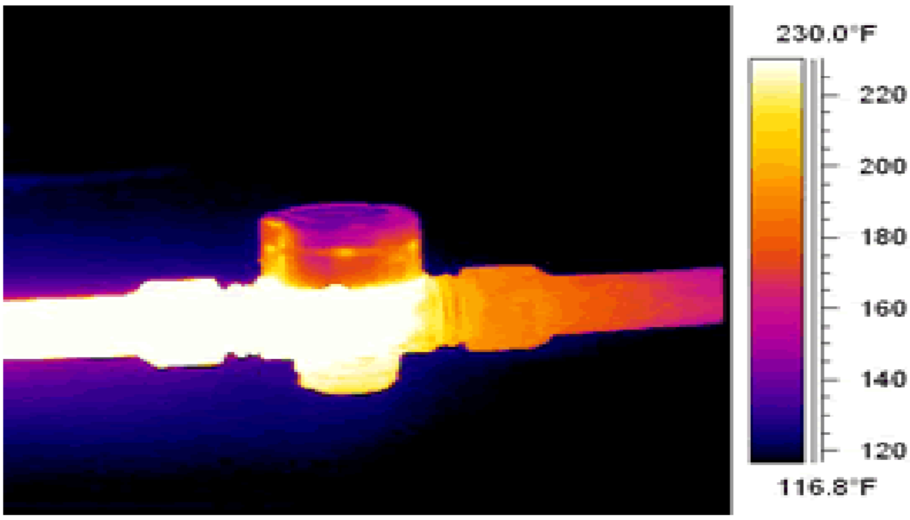
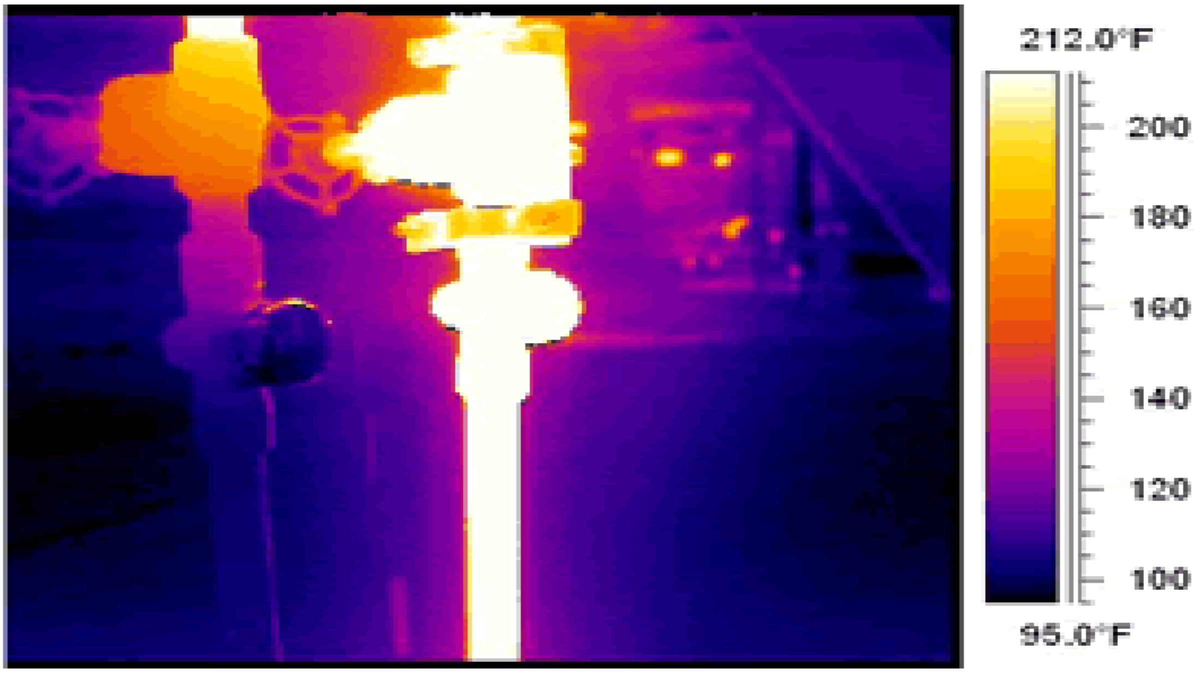


FIGURE 4: IR Scan of a Water Injection Point at the Inlet to a REAC

IR scan of a sound steam trap [Ref.: Irinfo.org]



IR scan of a failed steam trap [Ref.: Irinfo.org]



During our PPM check, severe corrosion detected by UT measurements. It was hard to prove the reliability of UT measurements and declare with 100% of confidence that the pipe has been corroded severely and it needed to shut down the unit in order to cut and inspect the pipe. So, the inspection team decided to conduct a complementary non-destructive method in order to make sure of the extent of corrosion. IR thermography was done and IR thermal images revealed significant temperature gradient in some parts of the pipe. Cutting the pipe approved our hypothesis. Here after thermal images and also pictures of pipe after cutting have been indicated.

Field Experience at SPGC

Fig 1: Results of UT measurements on 10 inch equalizer pipe in slug catcher indicated Severe metal loss in this pipe

Fig 2: IR image which indicates some parts of pipe has higher temperature compared to other parts (approx. 10 degree C temperature difference in the pipe is obvious), After cutting the pipe we observed that the sections of the 10 inch pipe with similar temperature to the main 42 inch pipe had no scale inside them, however the parts with higher temperature were full of scales.

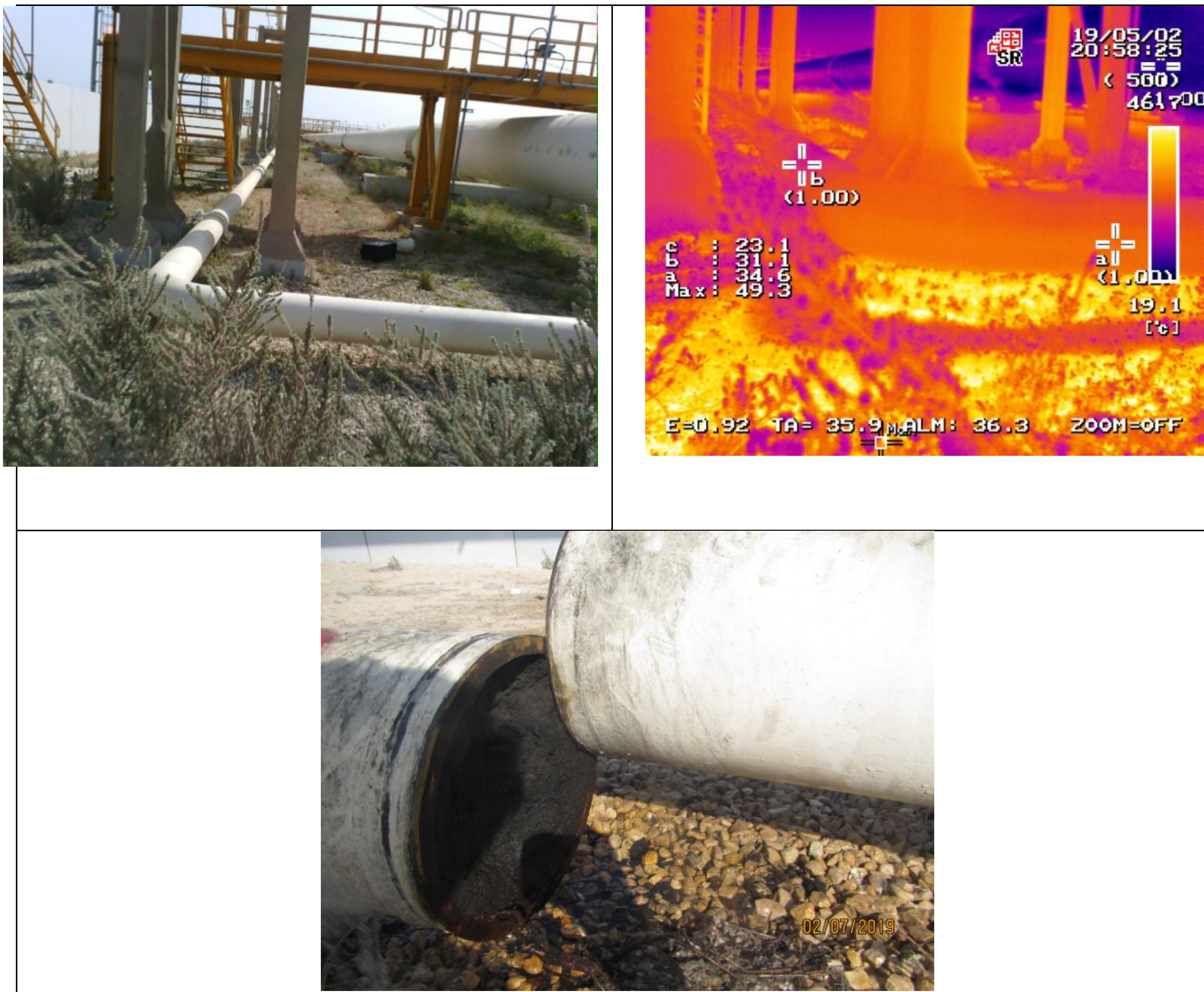


Fig 3: IR thermal image of the 10 inch line indicating the high temperature in this section of pipe. After cutting the pipe, it was full of scale. So, thermal imaging was able to be used as a complementary non-destructive tool beside UT measurement to determine the corroded areas.

Our experience indicated that IR thermography can be used as a helpful complementary non-destructive method beside UT measurements in order to detect corroded areas in the pipes of oil and gas industries.