Keeping Integrity in the (Corrosion) Loop…

ICorr Aberdeen
15 April 2014

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Overview

- Case studies from various systems (production / injection)
  - Scale in a PWRI pump (but not only scale…)
  - Failures of downhole chemical lines
  - Flow-induced corrosion and erroneous mitigation
  - Issues in water injection systems (oxygen control, bugs)
  - Corrosion monitoring and KPIs
- Inter-relationship between production chemistry and corrosion management / integrity assurance
  - How good are we at communicating with other disciplines
  - Are we asking the right questions
  - To the right people at the right time
  - Are all corrosion KPIs the same?
  - How many “reds” are needed before action is taken?
- Conclusions

Case study 1

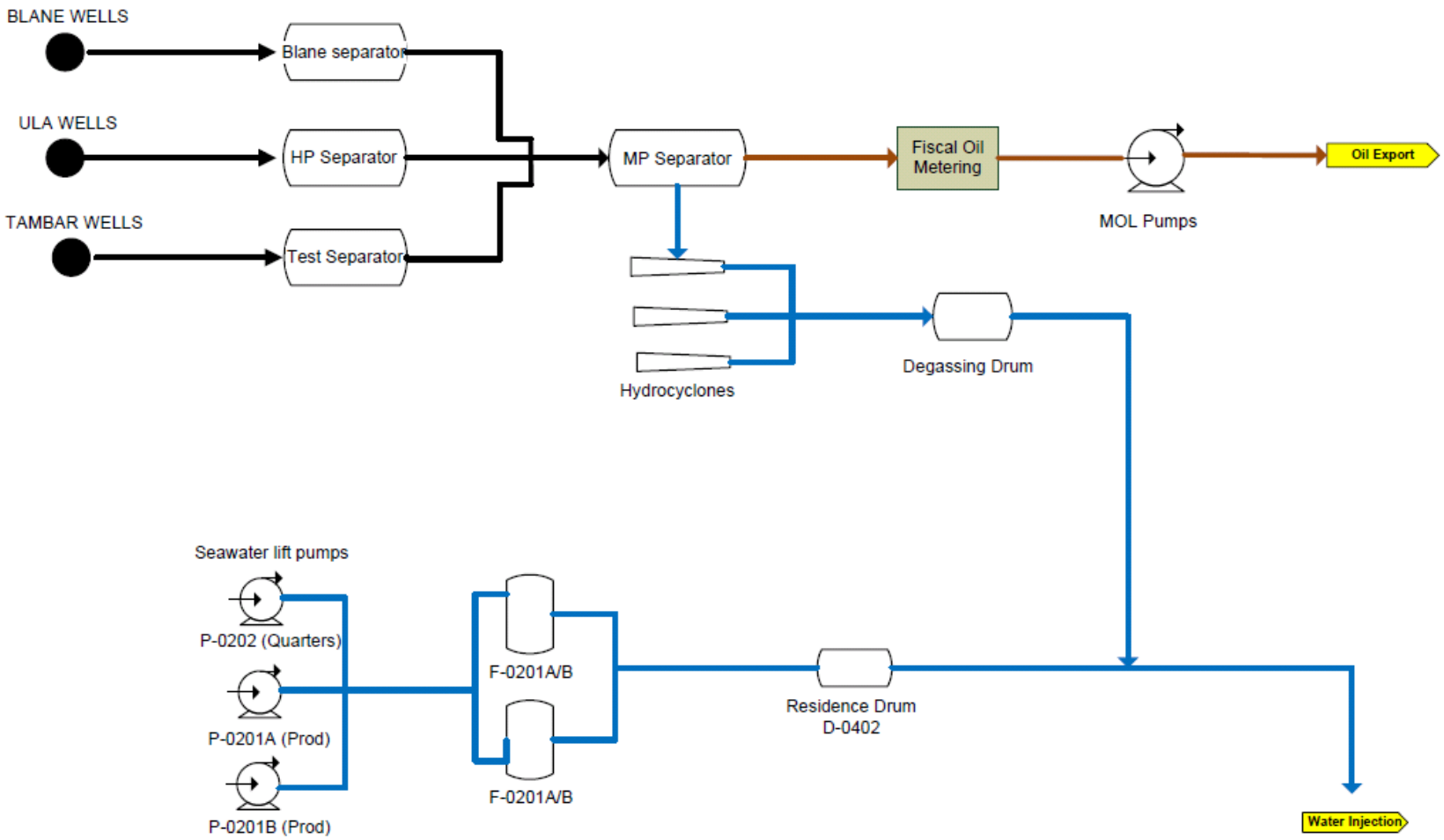
Scale in a PWRI pump

The Ula field

- Located in the southern Norwegian section of the N.Sea
  - Tambar (unmanned platform) ties back to Ula
  - Talisman's Blane field also ties back; on production since late 2007
- Field producing since 1986
- 3-bridge connected steel platforms for production, drilling, accommodation

- Sandstone reservoir, supported by means of SW, PW and gas injection
- In terms of scaling risk:
  - Barium sulphate ($BaSO_4$)
  - Calcium carbonate ($CaCO_3$)
  - Zinc/lead sulphide (ZnS and PbS)

Process system essentially



Solids at water injection pump

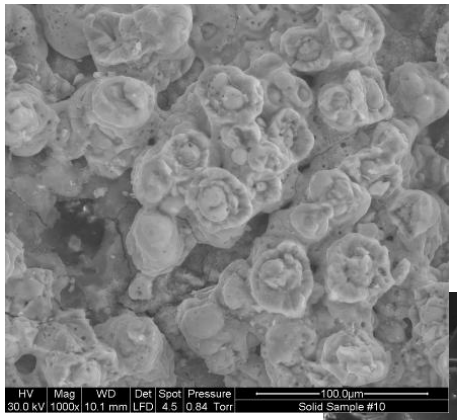
- Reports from the asset of significant solids accumulation in the water injection pump

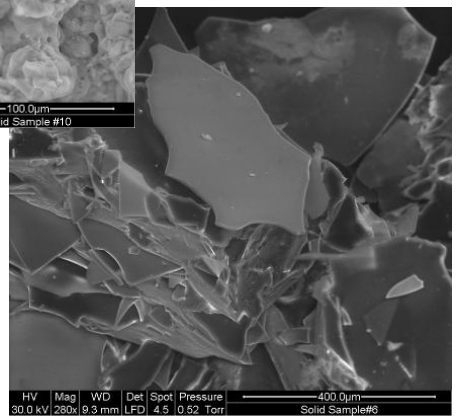
The identity of the solids

- First thoughts were it must be sand...
  - A large water producing well was shut-in (*ca.* 25,000 bbls of water/day)
- Quite a bit of scale inhibitor injected around the plant in the PW stream:
  - **200 ppm** on Tambar, as part of a field trial to inhibit sulphide scales
    - Lab testing showed that 25 ppm of the chemical would be sufficient to protect against $BaSO_4$ and $CaCO_3$ scales
  - **10-20 ppm** U/S the DHSV of a number of producing wells
    - In addition to scale inhibitor carryover from SISQ treatments, minimum inhibitor concentration typically **2-3 ppm**
  - **50 ppm** U/S the PW degasser
- Scale inhibitor injected in the PW well in excess of what would be required on the basis of scaling tendency for the plant

Analysis results

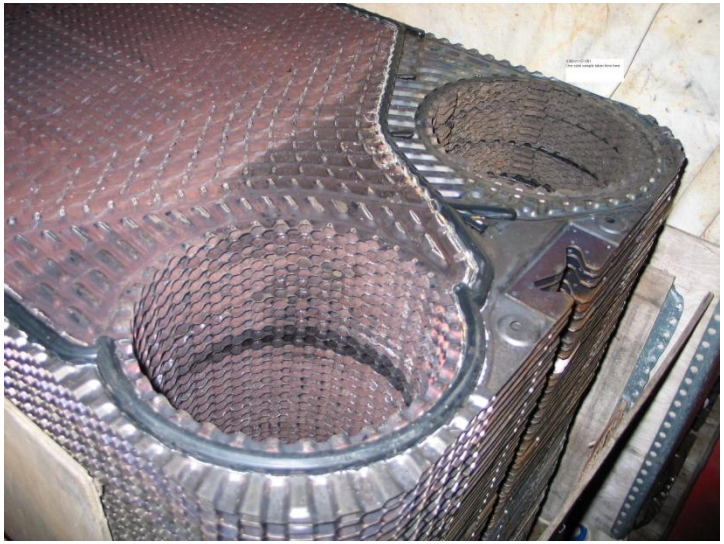
- Analysis showed solids to consist of primarily barite, sand and iron oxides (rust)
- “Cauliflower”-type structures seen under the microscope, characteristic of poor *in situ* crystallisation
- Sand grains coated with oil

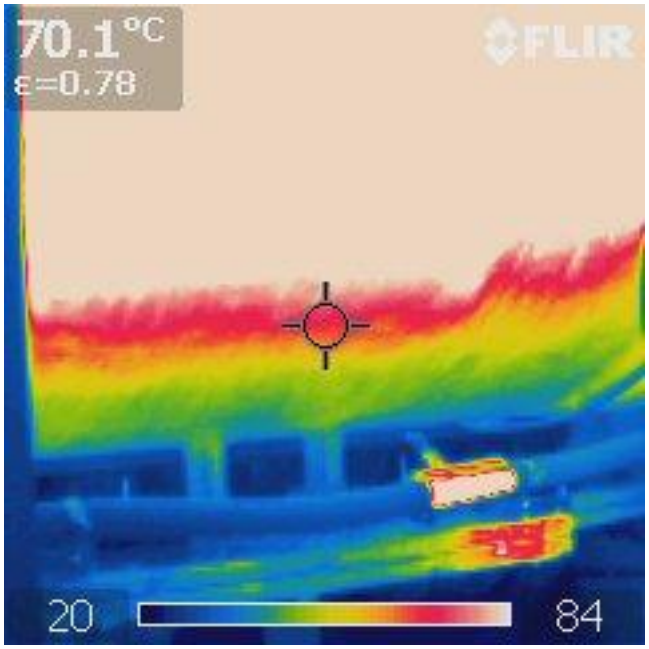




Where is the scale inhibitor?

- Sand findings in PW coolers earlier on the same year
- Also thermography showed degasser to have significant solids deposition
  - During shutdown around 15 m^3 of sand recovered
- Desanding unit present but had never been operational





Further impact of solids accumulation

- Separate findings from internal visual inspection of the PW degassing vessel
  - 5 areas of localised corrosion found on metal surface; max depth of attack at 55% of wall thickness
  - Attributed to microorganism-influenced corrosion (accompanied by unusually high H_2S readings, 140 ppmv)
  - Normally degasser temperature at 100 ^oC, but because of so much sand down to 50 ^oC → ideal for bacterial activity

Lessons learned

- Impact of unplanned changes to plant operation not fully appreciated
  - Having a large water producing well shut-in, the PW:SW injected ratio changed
  - No effective mechanism in place to capture changes in scaling risk
  - Presence of significant amounts of solids in system
  - Depleting the scale inhibitor from the produced water
  - Surface-active chemicals, adsorption on sand, scale etc, particles
  - By the time PW and SW commingled, insufficient chemical present in the water to inhibit $BaSO_4$ formation
- System cleanliness is key in maintaining a successful topsides scale management strategy

Case study 2

Failure of downhole chemical injection lines

Failings in procedures

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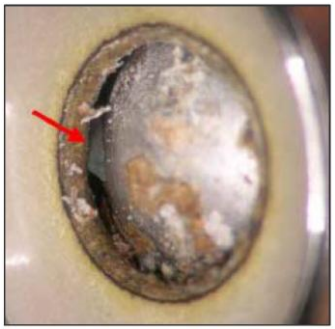
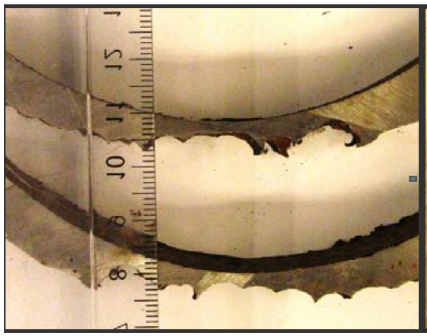
Case study: Downhole chemical injection lines

- Following completion, downhole CILs typically left filled with hydraulic oil:
  - Which needs to be displaced prior to injecting the intended chemical (in this case a scale inhibitor) to avoid undesirable reactions
  - **Procedure not followed**, line blocked on displacing with chemical, i.e. useless from day one of the well's life

- During shut-ins, **procedure of flushing CILs ignored**:
  - Gunking, precipitation of solids (e.g. polymers) when the solvent has boiled off
  - Formation of galvanic cells in the transition phase between the fluid surface of the chemical and the vapour-filled near-vacuum gas phase above; this leads to localised pitting corrosion inside the capillary line as a result of increased aggressiveness of the chemical under these conditions
  - Flakes or salt crystals formed as film inside the capillary line as its interior dries out could plug the line or gunk which prevents testable pressure integrity of the chemical injection system





Case study 3

Flow-induced corrosion and erroneous chemical application

Background to material failure

- A well that produces primarily water (95%)
- However water is hot (wellhead T is 97 °C)
  - Serves as a means to assist performance of 1st stage separator (which has no heater)
- Fluids transported through a 4-inch flowline made of carbon steel
- Through what is described as a “convoluted” path
  - Lots of bends and drops from height
- Flowline has experienced excessive metal loss and need for regular spool replacements
  - Evidence of preferential weld corrosion
  - Indication of general flow-induced corrosion
- Line treated with 50 ppm on total fluids with a combined scale/corrosion inhibitor
  - Higher concentrations also attempted but impact on OIW quality

Wall thickness inspection results

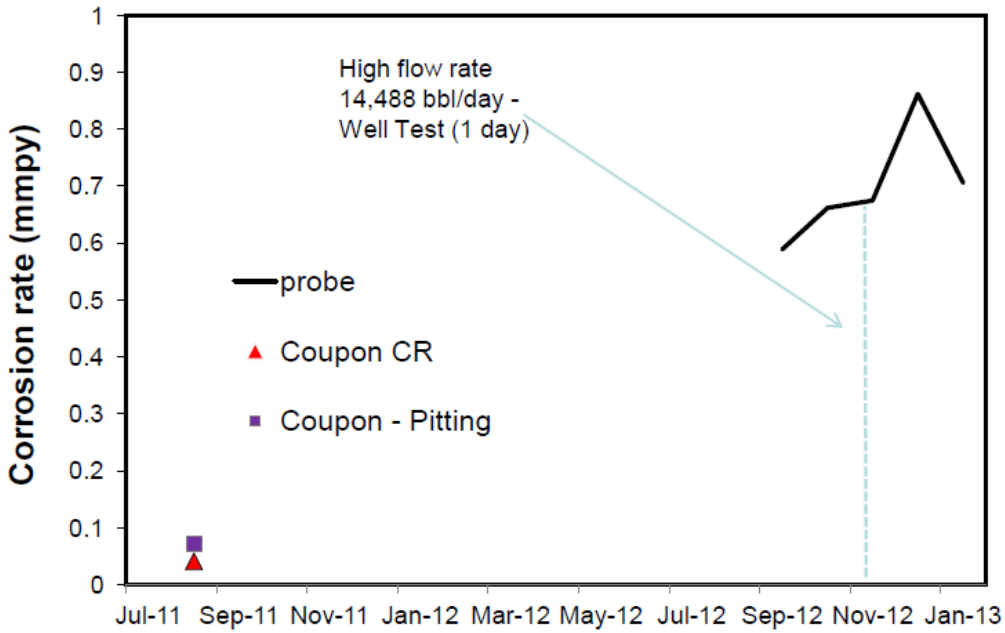
- Wall thickness and wall loss measurements over time for selected locations
- All clearly well in excess of 0.1 mmpy

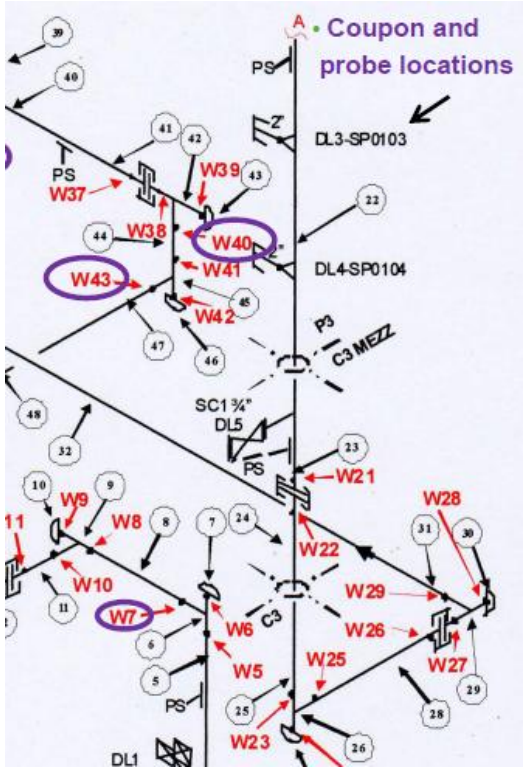
Wall Thickness Inspection

Feature		Orientation	Wall Loss (mmpy)
Weld	W7	H	1.46
Weld	W36	H	1.38
Weld	W40	V	1.62
Weld	W43	H	1.26
End Cap	F50	H	1.35
Weld	W46	H	2.26
Weld	W55	H	1.38

Probe and coupon results

- Probe and coupon are in a vertical pipework section:
  - However, worst metal loss measured in horizontal sections
- Only one coupon retrieval between Jan-2010 and Aug-2011:
  - Corrosion rate at 0.07 mmpy (pitting)
- Probe indicated higher corrosion rates during high fluid flow rates:
  - Average corrosion rate 0.7 mmpy





From the P&ID and isometrics to CFD...

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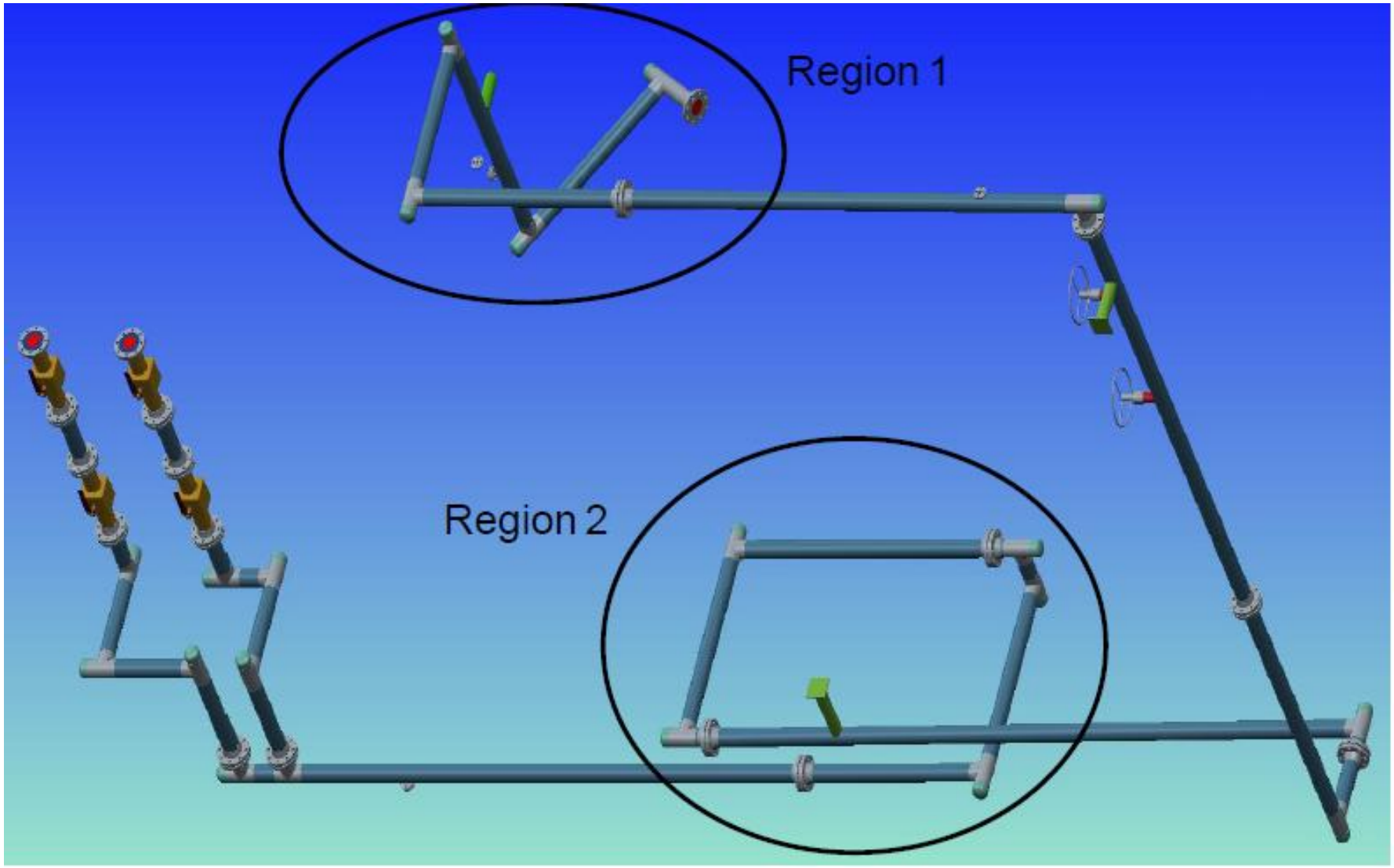
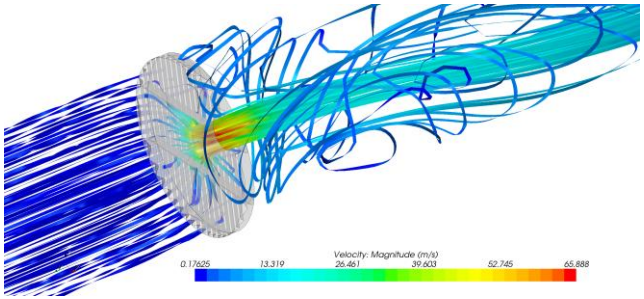
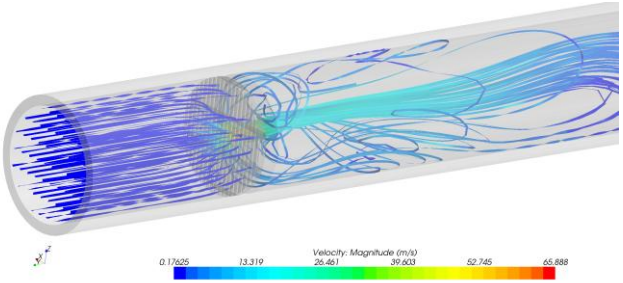
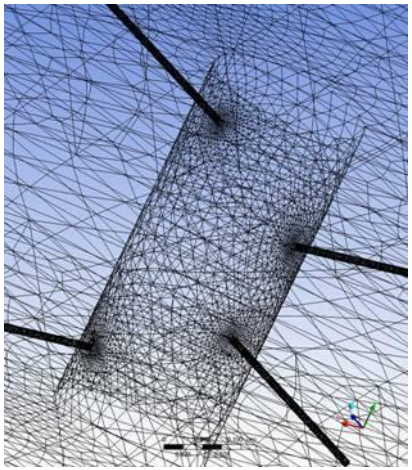


What is CFD

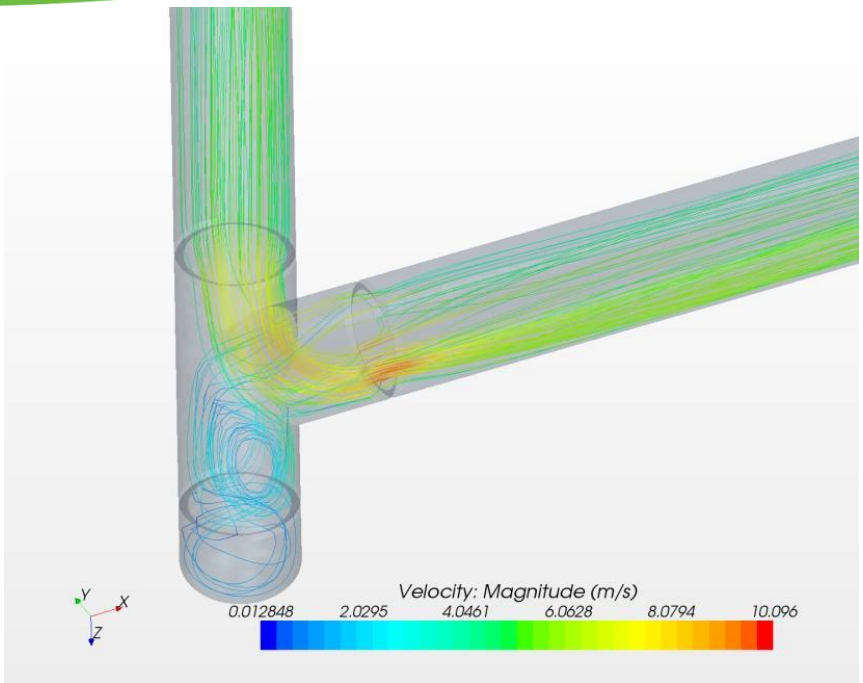
- CFD is a computational method used to model and simulate fluid flow in a ‘bounded domain’
  - So as to generate what is known as the ‘volume mesh’ where a fluid would flow
- Fluid can be any type: liquids, gases, particles and mixtures
- Simple physics:
  - Motion of a fluid element in a 3D space as described by continuity, momentum and energy equations
- Powerful technique & proven technology (aerospace, automotive industries)
- Conventional velocity modelling of flow in pipes assumes uniform flow for the cross-sectional area
  - Maybe true for some flow in straight pipes, definitely not in bends and tortuosity in more convoluted flowlines

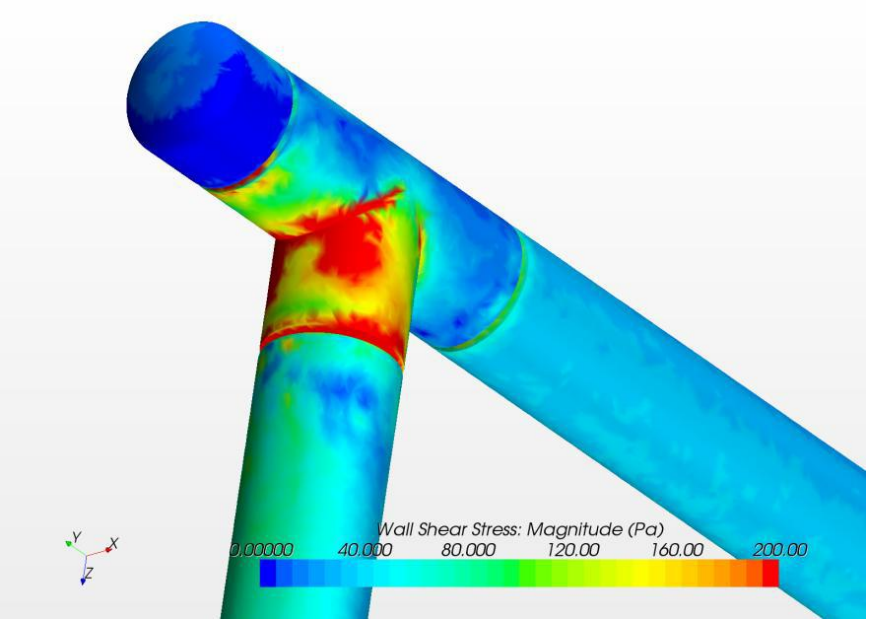


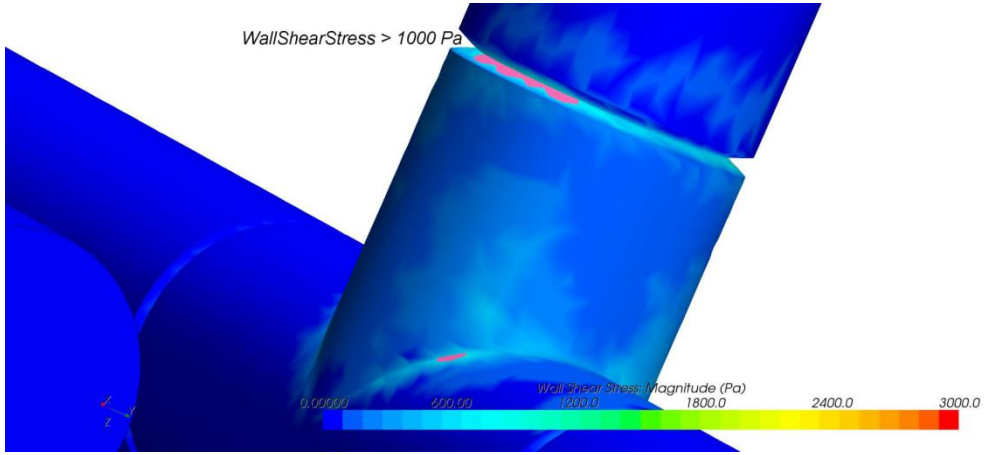




The results







Flow	Region	V_{max} (m/s)	Max WSS (Pa)
Low	1	6.5	525
	2	7.0	1,316
High	1	10.8	1,298
	2	11.6	3,156

Historical chemical changes

- Effort to select a chemical that would cover whole field (logistics/economics)
- Combined scale/corrosion inhibitor was selected for application in flowline
- Poor management of change process, inadequate follow-up of testing parameters and adherence with KPI

Parameter	Lab testing	Field / well data
Temperature (°C)	80 / 90	97
Pressure (bara)	**15**	WHP 154, P_b 100
pCO_2 (bara)	0.53 / 0.90	3.54
Velocity (m/s)	**1.24**	At least 5 (CFD)
Welds	**No testing**	-

- Lab equipment temperature limitations
- Pressure used <u>downstream</u> of flowline – that of the separator??
- Velocity representative of another pipeline in the field
- Welds are the weakest part of the pipe – no testing is unacceptable

Lab results using wrong inputs

- Using initial (lower) T and pCO_2:
  - 6.35 mm/yr (DeWaard '93 for liquid velocity of < 1.5 m/s)
  - 3.36 mm/yr (modified DeWaard '95 for multiphase flow)
  - CR post-inhibition in lab tests > 0.1mm/yr – <u>why was this accepted?</u>

Product	Concentration	Initial Corrosion Rate (mm/yr)	Final Corrosion Rate (mm/yr)	Percentage Inhibition %
G10000	50 ppm	1.33	0.18	85.94
		1.49	0.15	89.90
G10150	50 ppm	1.09	0.10	90.69
		1.07	0.14	86.19

- Revisiting the inputs following continuing metal loss measurements:

Sample Date	G10150 Dose (ppm)	Initial corrosion rate (mmpy)	Final Corrosion Rate (mmpy)	Percentage Inhibition (%)
18/01/12	50	11.52	1.58	86.28

Using more accurate inputs

- This gives a pCO_2 of **3.54 bara** (*cf.* max 0.9 bara used for lab testing) and CR of up to (depending on prediction model used) 25 mmpy

Pressure (Bar)[1]	Temperature (°C)	Velocity (m/s)	Predicted Uninhibited Corrosion Rate- $CR_{uninhibited}$ (mmpy)		
			De Waard 93 (valid only for low flow)	De Waard 95	Multiphase [2]
100	97	1.24	10.4	10.4	NA
		2		13.6	NA
		5		20.2	27.0
		8		23.6	NA
		10		25.0	NA

- Note: Corrosion models do not predict corrosion on welds

- **Question:** is therefore carbon steel the right material for this application?

Efficiency limits of corrosion inhibitors

- Typical target is an inhibited corrosion rate of ≤ 0.1 mmpy for carbon steel
- From experience, efficiency of inhibition varies widely with operating conditions
- Published guidelines to evaluate likelihood of inhibition success – 'environmental score':

$$\textit{Environmental score} = \textit{Temp } (^{o}C) / 40 + \textit{Shear (Pa)} / 240 + \textit{TDS (ppm)} / 125{,}000$$

- **Category 1 (ES = 0 – 2.5), low risk:** large number of successful inhibitors, typical concentrations, in brine, of up to 50 ppm may be expected.

- **Category 2 (ES = 2.5 – 4.0), medium risk:** corrosion inhibition proven to be effective, however higher concentrations are likely, typically up to 100 ppm in brine. Highly reliable chemical injection systems recommended.

- **Category 3 (ES = 4.0 – 5.5), high risk:** very challenging conditions for corrosion inhibition; significant problems in finding successful inhibitors. Inhibition likely to be effective but concentrations of ≥ 300 ppm in brine may be required. Highly reliable chemical injection skids should be implemented with integrated control systems to the control room.

- **Category 4 (ES > 5.5), very high risk:** projects need to be sure that there is an inhibitor available that can perform in their specific conditions <u>before selecting carbon steel plus inhibitor</u>. There *may* be inhibitors but there has been little success in lab tests except at very high concentrations (≥400 ppm). Need highly reliable chemical skids and control room alarms.

Material selection

- Prompted by the findings of this investigation, obvious that a re-evaluation of the original material selection would be required
- Flowline has a corrosion allowance of **6 mm** and was designed for a 20 yr field life
- Calculating the corrosion allowance for the actual conditions showed that this ranges between **22 – 52 mm** for a 20 yr life
  - Depending on flow conditions
  - And corrosion inhibitor availability (at least 90%)

- According to NORSOK M-001 and ISO 21457:
  - Carbon steel is acceptable material selection *only* when corrosion allowance is up to **10 mm**
  - Here <u>by definition</u>, therefore, higher CRA or clad carbon steel would be required

- **Conclusion: original material selection wrong for the application**
- Like for like replacements and injecting corrosion inhibitor will not mitigate against the problem

Case study 4

Issues in water injection systems

In water injection systems

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Case study: macrofouling of SW lift pumps & caissons

- SW contains microorganisms (algae, plankton, bacteria...)
- Water has to be continuously chlorinated to minimise influx of marine life
- Typically hypochlorite (=bleach) generated *in situ* using an electrochlorinator
- But frequently down...

- Electrochlorinators tend to accumulate calcium/magnesium hydroxide sludges
- **Advice:** injection lines need periodic flushing with acid to dissolve
  - However, not all assets make provision to follow cleaning procedure so sooner or later lines block
- Once biomass established, impossible to remove with chemicals
- Experience from caissons is that frequency of marine life re-establishment on a cleaned area increases between cleanups (probably related to surface roughness)
- Big job to pull out pumps and replace...

For seawater specifically

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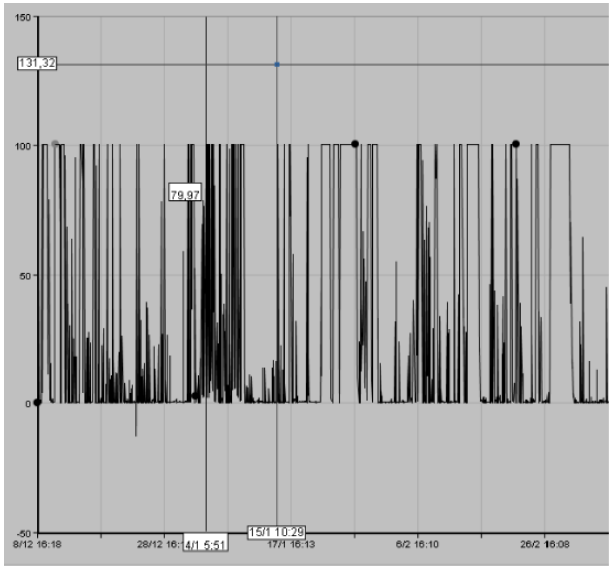
Case study: oxygen control

- Dissolved oxygen in SW is extremely corrosive
- For carbon steel systems needs to be < 20 ppb (SW ~ 10,000 ppb oxygen)
- Reduction mechanical (deaeration) supplemented by scavenger
  - Too much scavenger is corrosive and food for bacteria...
- Unfortunately, not easy to achieve continuously despite optimistic predictions
- Biocide treatments confuse oxygen analysers
- Over-reliance on manual detection methods (colorimetric, Chemets)
- Guidelines typically in place to dump back to sea if water > spec for say more than 2 hrs – **rarely observed**
- Result:
  - Flowline and well corrosion (iron oxides, hydroxides and carbonates)
  - Iron sulphide if combined with bacterial activity (and souring)
  - Injectivity decline
  - Iron essential nutrient for bacteria growth (not necessarily SRB)

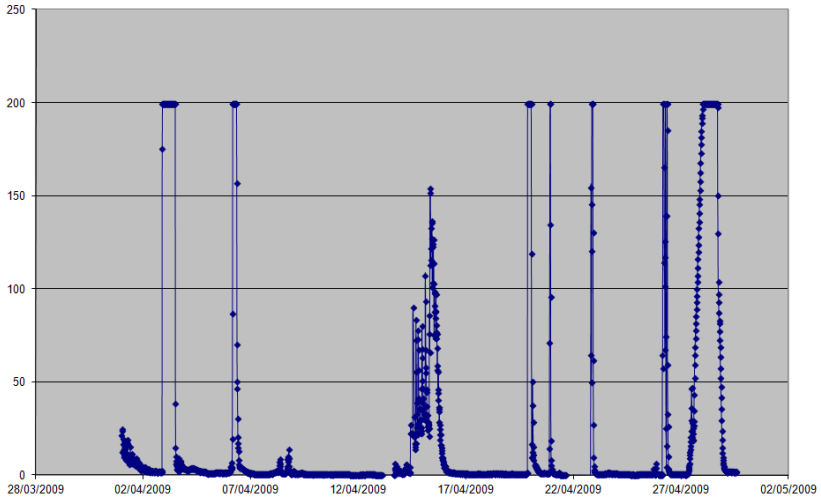
Oxygen control

- A peculiar situation whereby manual oxygen readings were consistently ZERO
- But online analyser showed significant deviation from acceptable threshold
- Discovered that Chemets used were the wrong range (up to 1,000 ppb instead of 0-20 ppb)
- Impossible to visually detect colour changes at low end of spectrum
- KPI box for manual readings ‘ticked’ but in practice no corrosion control!



Oxygen and bugs

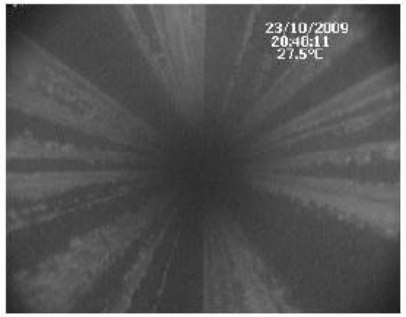
- **“But we’ve never had any issues with oxygen control...”**
- Coupon (photo) was in WI flowline D/S deaeration for 3 months
- Oxygen analyser trends (just one month) showed poor compliance with target
- Significant injectivity decline in a well that was < 18 months old
- Bailer run retrieved FeS solids, followed by a Venturi run



Good bugs / bad bugs...

- **Case 1:** Wash water (desulphated) to reduce salinity of highly saline tiebacks
- Desulphated SW requires different treatment chemicals
- Wrong biocide used...

- **Case 2:** calcium nitrate injection to suppress souring
- Uncontrolled chemical injection
- Nitrate utilising bacteria eutrophication
  - Corrosion & injectivity decline



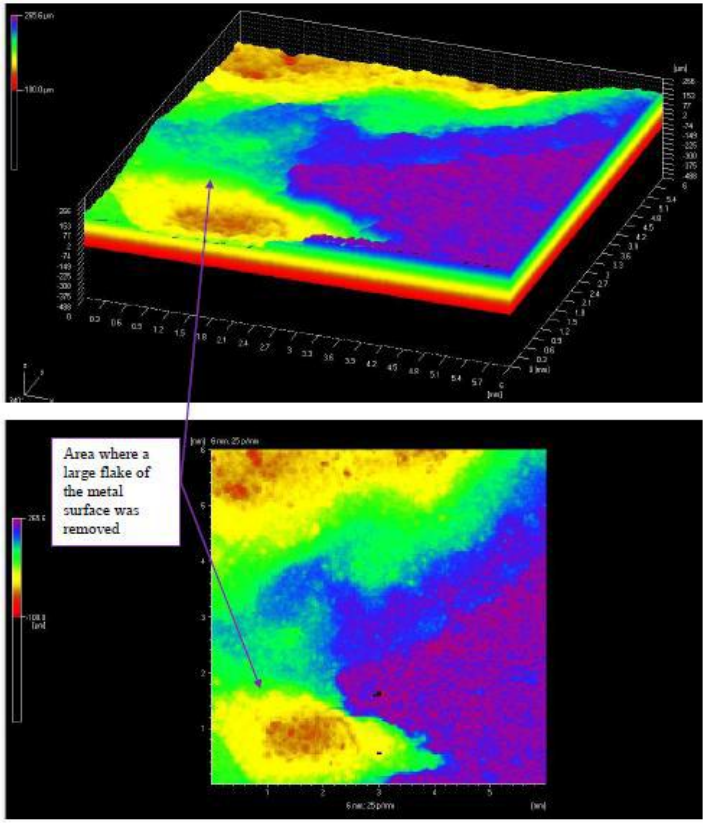
Case study 4

Corrosion monitoring and KPIs

Corrosion monitoring

Case study 1: coupon retrievals

- Coupons regularly retrieved U/S a deaerator in a seawater injection system
- What was the asset hoping to see from a coupon exposed to seawater
- Especially since only means of biociding in that location is chlorination
- Normally more interested in the activity of anaerobic rather than aerobic microorganisms



Case study 2: coupon retrievals

- In a flowline that had been shut-in for 2 years because of a hydrate plug problem
- But coupon change-outs were in the work pack so...

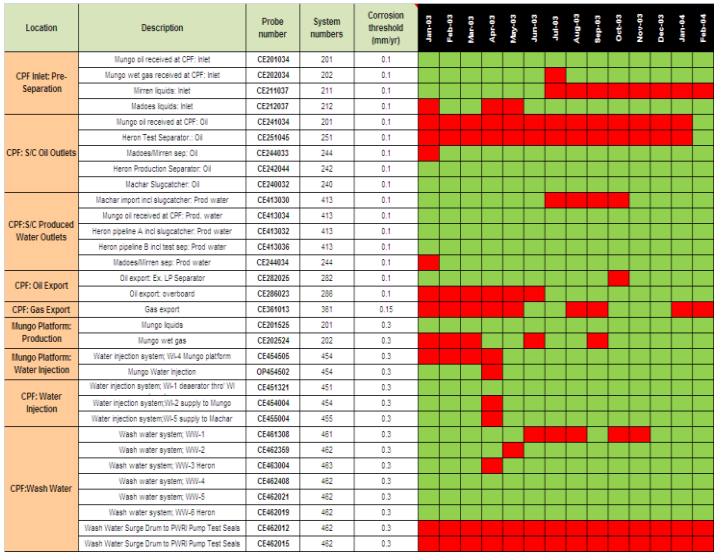
Corrosion monitoring

Case study: KPIs

- How many “reds” are needed before action is taken?
- At what point does it become pointless to report a parameter that cannot be measured reliably and at an acceptable frequency?

- How much authority does the reporting party have to affect required actions? Especially when some aspects depend on 3rd parties (computer systems, data loggers, etc.)

- Are all KPIs of equal significance, i.e., is a “red” in a glycol pH system equal to “red” for dissolved oxygen content in SW or to a “red” for a pipeline FSM spool? Who decides?



Location	Description	Probe number	System numbers	Corrosion threshold (mm/yr)	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04
CPF Inlet: Pre-Separation	Mungo oil received at CPF: Inlet	CE201034	201	0.1														
	Mungo wet gas received at CPF: Inlet	CE202034	202	0.1														
	Mirren liquids: Inlet	CE211037	211	0.1														
	Madoes liquids: Inlet	CE212037	212	0.1														
CPF: S/C Oil Outlets	Mungo oil received at CPF: Oil	CE241034	201	0.1														
	Heron Test Separator.: Oil	CE251045	251	0.1														
	Madoes/Mirren sep: Oil	CE244033	244	0.1														
	Heron Production Separator: Oil	CE242044	242	0.1														
	Machar Slugcatcher: Oil	CE240032	240	0.1														
CPF:S/C Produced Water Outlets	Machar import incl slugcatcher: Prod water	CE413030	413	0.1														
	Mungo oil received at CPF: Prod. water	CE413034	413	0.1														
	Heron pipeline A incl slugcatcher: Prod water	CE413032	413	0.1														
	Heron pipeline B incl test sep: Prod water	CE413036	413	0.1														
	Madoes/Mirren sep: Prod water	CE244034	244	0.1														
CPF: Oil Export	Oil export: Ex. LP Separator	CE282029	282	0.1														
	Oil export: overboard	CE286023	286	0.1														
CPF: Gas Export	Gas export	CE361013	361	0.15														
Mungo Platform: Production	Mungo liquids	CE201525	201	0.3														
	Mungo wet gas	CE202524	202	0.3														
Mungo Platform: Water Injection	Water injection system; WI-4 Mungo platform	CE454505	454	0.3														
	Mungo Water Injection	OP454502	454	0.3														
CPF: Water Injection	Water injection system; WI-1 deaerator thro' WI	CE451321	451	0.3														
	Water injection system;WI-2 supply to Mungo	CE454004	454	0.3														
	Water injection system;WI-5 supply to Machar	CE455004	455	0.3														
CPF:Wash Water	Wash water system; WWI-1	CE461308	461	0.3														
	Wash water system; WWI-2	CE462359	462	0.3														
	Wash water system; WWI-3 Heron	CE463004	463	0.3														
	Wash water system; WWI-4	CE462408	462	0.3														
	Wash water system; WWI-5	CE462021	462	0.3														
	Wash water system; WWI-6 Heron	CE462019	462	0.3														
	Wash Water Surge Drum to PVRI Pump Test Seals	CE462012	462	0.3														
	Wash Water Surge Drum to PVRI Pump Test Seals	CE462015	462	0.3														

The bottom line…

(Communication)^3

- Some integrity problems are the result of
  - Inadequate technical understanding
  - Inadequate procedures and quality control
  - Inadequate data and trends

- Almost all integrity problems are the result of inadequate communication...
  - Asking the right questions – how can you ask questions on things you don't understand or know about
  - At the right time – preferably before a failure, before authorising lab tests, before deploying a new chemical, before signing off a material selection
  - Asking the right person – not always direct access to appropriate expertise
  - Lessons learned – many circulate within companies, however, seems to take multiple incidents for learning to be taken up and eventually become a set procedure; hardly ever handed over when new people take on a position

- Some thoughts on the **H** of HSE...
- Finally: the integrity engineers are a chemist's best friends
  - Since they take all the interesting photos! ☺

Thank you!

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