Piping Circuitization and Risk-Based Inspection Requirements

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• Leader in Risk-Based technology development for plant applications
• Project Manager of API RBI Joint Industry Project since 1996
• Member of API committees for development of API 580 and API 581 recommended practices
• Developer and Official Trainer for API 580/581 Public Training course
• Vice President and Principal Engineer with Equity Engineering
Purpose

• Purpose of Presentation
  – Using API 580 and 581 for piping Risk Assessment
  – Systemization and circuitization of piping
  – Understand complementary nature of Materials Operating Envelopes (MOE)
  – Understand challenges of piping inspection

• Sources
  – API RBI User Group Joint Industry Project
  – API 580
  – API 581
  – API 570
  – API 571
  – API RBI Software
Presentation Outline

- Introduction
- Piping Programs Characteristics
- Available Analysis Tools
- A Complementary Approach: Material Operating Envelopes (MOE)
- Piping Systemization and Circuitization
  - Piping study case study 1
  - Piping study case study 2
- Piping TML Data Analysis & Benefits
- Summary & Conclusions
The Goal

Assure regulatory and corporate compliance, and ensure reliable use of piping (and equipment) for finite run times, while measuring, managing and minimizing risks and eliminating non-value adding activities and costs.
Introduction

• Historical industry statistics attribute piping failure to be leading cause of large property losses
• Industry data indicates that the most frequent unexpected failures occur in piping systems (30-45%) due to localized corrosion, often by undetected mechanisms
• The majority of industry piping programs use a classification system from API 570 for criticality ranking
• Straight beam ultrasonic inspection (UT) is the most commonly used method for thinning damage detection
• Quality of inspection data, coverage of inspection points and a link of inspection locations and type to damage mechanism must be analyzed to assure program effectiveness
• Correct CML/TML placement needs to be determined in conjunction with active damage mechanisms identified by experienced corrosion/materials engineer

*Reference Marsh & McLennan, API Rand and E²G studies.
Introduction

• “Losses in the refinery industry have continued to increase over the last few years and the causes highlight the aging facilities in this category. A significant number of larger losses (over $10,000,000) have been caused by piping failures or piping leaks, leading to fires and/or explosions. Several large losses due to piping failures were due to corrosion issues or using the wrong metallurgy…..”

Introduction

The explosion occurred when employees were attempting to isolate a leak on a condensate line between the NGL plant and the refinery. Three crude units were damaged and two reformers were destroyed. The fire was extinguished approximately nine hours after the initial explosion. Five people were killed and 50 others were injured. Initial investigation into the loss indicates a lack of inspection and maintenance of the condensate line.

June 25, 2000
Mina Al-Ahmadi, Kuwait
$412,000,000 (2000 dollars)

Introduction

- Routine straight beam ultrasonic inspection (UT) is by far the most common method (and often the only) of inspection independent of the expected damage mechanism assessment.

- Often a detailed analysis of the UT data is not done to determine the quality of the data, adequate coverage of inspection points, etc.
Introduction

• Most refining, mid-stream, and chemicals pressurized equipment was designed and built for an operating basis different than current operation

• Plants continuously “tweak” the process to raise throughput or process poorer quality (lower cost) feedstocks (crudes or intermediates)

• Long term effect is cumulative so that minor changes may cause a significant increase in damage rates
Piping Programs

• CMLs must be placed in the correct locations, and used with appropriate NDE
  – Guidance/Input from corrosion engineers for placement decisions
  – RBI not used to quantify risk reduction/investment payback
  – Use statistics as applicable to determine optimal sampling

• An overabundance of CMLs results in non-value-added activities

• Integrate and define the value of corrosion reviews, Fitness for Service evaluations, RBI and statistical analyses in the inspection and planning process for optimal effectiveness
Piping Programs

• Considerations for Inspection Database programs (IDBMS)
  - How much change has occurred between measurements?
  - How accurate are the measured corrosion rates?
  - How do we use retirement dates (based on ½ life)?
  - What is the basis for retirement limit (nominal + CA)?
  - How was the program initially set-up?
  - How were circuits defined?
  - Was corrosion and expected damage mechanisms used for defining inspection scope, type and location?

• Plants are aging
  - Failure rates will increase without effective change
Piping Programs

• Requires a shift from original basis to consider why, where, when, how to inspect

• RBI Principles
  – Qualitatively grade the effectiveness of NDE
  – Probability of failure involves uncertainty
  – Consequence

• FFS Principles
  – Limiting flaw size
  – Accuracy of NDE

• Proactive approaches
  – Corrosion systemization and circuitization
  – Operating Envelopes (MOEs)
  – Management of Change (MOCs)
Available Tools

• Codes & Standards permit use of and provide minimum guidelines for
  – RBI
  – FFS
  – Jurisdictional

• Supporting documents
  – 580
  – 581
  – API/ASME ISIJC
Available Tools

• Codes and Standards
  – Latest editions of API 570, 574, 579, 580, 581

• RBI
  – Damage mechanism assignment is a critical element

• FFS
  – Engineering Analysis
  – Damage mechanism assignment is a critical element

• Corrosion and materials review
  – Systemization and circuitization
  – RBI damage mechanism assignment
  – MOE
Available Tools

• Materials/corrosion review with assignment of active damage mechanisms
  – Critical to the success of any equipment reliability program
  – Critical to success of any RBI process
  – Required by codes, standards and regulators
  – Should include special emphasis mechanisms (e.g., Stress Corrosion Cracking, Creep, Wet H_2S)
When to Consider an MOE

- Complimentary Approach: Material Operating Envelopes (MOE)
- Proactively or in response to an incident
- In conjunction with a critical Fitness-For-Service assessment
- Next step after doing RBI
Materials Operating Envelopes

• Identify key parameters and ranges
• Traditional piping inspection programs rely on future operating conditions replicating past operating conditions
• RBI typically focused more on inspection activities than on controlling operations and identifying monitoring activities
• Knowledge and control of operating envelope helps provide an improved chance for reliability and safety, due to increasing knowledge of actual operating parameters
• An MOE defines the envelope for predictable degradation versus specific operating parameters
Defining Limits

- Similar to KPRP’s
- Contain some parameters that may not be controllable, but must be measured and trended
- Defines limits operation (feed contaminant content, pH, flow rate, temperatures, chemical or water injection rates) and acceptable levels of corrosive constituents
- Control of operating parameters to minimize corrosion/degradation
- Modeling required with sampling/inspection to verify assumptions about constituents or conditions not being present
- Limits exceeded and degradation accelerated may trigger inspection, RBI, FFS updates or other actions
Inspection Benefits of MOE

- Identify need for more UT coverage in some areas and less in other areas
- Identify improper inspection procedures being applied
- Identify equipment taken out of service with blinding points that create process deadlegs
- Identify equipment being cycled in/out of service creating CUI concerns
Piping Circuitization

• Use an experienced corrosion/materials engineer to define systems in each unit
• Define corrosion circuits within each system based on materials of construction, operating conditions and active damage mechanisms
• Circuit identification and naming convention is used for both API RBI and IDBMS programs to provide linking and sharing inspection data
• Analysis is performed on circuit inspection results to determine circuit corrosion rate and measured thickness/dates for circuit components
• Circuit corrosion rates are used in API RBI to calculate circuit risk
• Determine the circuit and component next inspection date and inspection effectiveness, including detailed inspection plan
• Review or Placement of CML/TML recommended by corrosion/materials engineer
• CML/TML installed and documented on piping Isometric drawings
Example 1

HDS Unit
System Key – HDS

1) HDS Feed
2) 1st Stage Reactor & Effluent
3) 2nd Stage Reactor & Effluent
4) Recycle Hydrogen & Effluent
5) Make-up Hydrogen
6) Naphtha Stripper Feed
7) Naphtha Stripper Overhead & Reflux
8) Naphtha Stripper Bottoms & Reboiler
9) CCR Feed
10) #1 Reactor Feed Effluent
11) #2 Reactor Feed Effluent
12) #3 Reactor Feed Effluent
13) #4 Reactor Feed Effluent
14) Reformer Recycle Hydrogen
15) Net Gas Compression
16) Net Gas Chloride Treaters
17) LPG Recovery Propane Compression & Chiller
18) Debutanizer Feed
19) Debutanizer Overhead & Reflux
20) Debutanizer Bottoms & Reboiler
21) Benzene Overhead & Reflux
22) Benzene Aromatic Product
23) Benzene Bottoms & Reboiler
Circuit Summary

- System Summary – Feed line carrying Virgin Naphtha, Cracked Naphtha and Heavy Naphtha through preheat to first stage reactor
- Circuit Summary – Circuit 3 includes piping from first stage reactor feed (channel) to first stage reactor
- Material of Construction – Carbon Steel
- Estimated Corrosion Rate – 2 mpy
- Corrosion Type – General
- Primary Damage Mechanism – None
- Specific Location Concerns – None
- Deadlegs – 2 potential, created bypass line and closed valve during operation
Circuit Summary

- System Summary – Second Stage Reactor & Effluent
- Circuit Summary – Circuit 1 piping from the Second Stage Reactor Fired Heater to Second Stage Reactor
- Material of Construction – 9Cr - ½ Mo
- Estimated Corrosion Rate – 4 mpy
- Corrosion Type – General
- Primary Damage Mechanism – H₂H₂S, HTHA (none)
- Specific Location Concerns – Straight run piping with potential high velocity conditions
Circuit Summary

- System Summary – Second Stage Reactor & Effluent
- Circuit Summary – Circuit 5 Piping from the Reactor Effluent Air Coolers to the Shell Side of Reactor Effluent Trim Cooler
- Estimated Corrosion Rate – 7 mpy
- Corrosion Type – Local
- Primary Damage Mechanism – Ammonium Bisulfide/Chlorides
- Specific Location Concerns – Elbows, high velocity areas (>20 ft/sec)
Piping Risk Analysis Summary

• HDS Unit with 8 PFD, 67 P&ID’s and 1,670 lines in the line list provided for the study:
  - Develop corrosion systems and circuits with common damage mechanisms and expected corrosion rates for the main hydrocarbon containing lines and branch connections (utilities services, drain lines, flare lines were excluded).
  - Integrate the new defined corrosion circuits with existing RBI file (naming conventions, re-grouping at the circuit level).
  - Estimate the corrosion rate on a circuit basis and add to the RBI file.
  - Add all necessary mechanical and operating data for each piping circuit in the existing RBI files and recalculate the risk/inspection plans for this Unit.
  - Develop color coded piping System and Circuit drawings utilizing the PFD’s and P&ID’s.
HDS Summary

• 23 Systems
• 146 Circuits
• 27 circuits (~18%) which potentially problems due to:
  - Material of construction at the current operating conditions
  - Piping design (location of check valves, specification break, etc.)
• Potential problems due to corrosion in H₂S, Chlorides, Ammonia bisulfide, Ammonia Chlorides environments; High Temperature service (creep); Corrosion Under Insulation (CUI)
Example 2

Gas Plant
## System Key – Gas Plant

<table>
<thead>
<tr>
<th>Process Stream</th>
<th>Identifier</th>
<th>Color Code</th>
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<tbody>
<tr>
<td>RAW FEED</td>
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<td>STABILIZED FEED CONDENSATE</td>
<td>STAB</td>
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<tr>
<td>COMPRESSION</td>
<td>COMP</td>
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<td>DEHYDRATION 1</td>
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<td>DEHYDRATION 2</td>
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<td>CRYOGENICS TRAIN B</td>
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<td>DEMETHANIZER BOTTOMS TRAIN A</td>
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<td>DEMETHANIZER OVERHEADS TRAIN A</td>
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<td>REGEN</td>
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<tr>
<td>REFRIGERATION</td>
<td>RFG</td>
<td></td>
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<td>LUBE OIL</td>
<td>LBOIL</td>
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<tr>
<td>FUEL GAS</td>
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<td>HEAT MEDIUM</td>
<td>HTOIL</td>
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<td>FLARE</td>
<td>FLR</td>
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<tr>
<td>DRAIN</td>
<td>DRN</td>
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</table>
Feed System
Feed System
Feed System
Circuit Summary

• System Summary – Feed line from offshore platforms to Dehydration system
• Circuit Summary – Circuit 6 includes piping from the Stabilizer Feed Drum top to the Stabilizer Overhead Compressor Skid
• Material of Construction – Carbon Steel
• Estimated Corrosion Rate (internal) – 3 mpy
• Corrosion Type – General
• External Corrosion Rate – 2.9 mpy
• Primary Damage Mechanism – CUI
• Specific Location Concerns
  – Internal corrosion - low points and deadlegs, areas where water collects
  – Damaged insulation or weatherproofing
• Deadlegs – 3 potential
Cryogenic System
Circuit Summary

- System Summary – Piping from the Expander to Demethanizer Column and from the Cold Gas/Gas Exchangers; MeOH injection point in this system
- Circuit Summary – Circuit 1 includes piping from the Expander to the Demethanizer and to/from the Cold Side Reboiler
- Material of Construction – Stainless Steel
- Estimated Corrosion Rate (internal) – 0 mpy
- Corrosion Type – General
- External Corrosion Susceptibility – None
- Primary Damage Mechanism – CUI Austenitic Stainless Steels
- Specific Location Concerns – Possible CUI concerns at interface of insulated equipment and un-insulated protrusions
- 7 potential Deadlegs; 1 potential injection/mix point
Gas Plant Summary

- 18 Systems
- 344 Circuits
- 28 circuits (~8%) with potential internal corrosion in aqueous conditions
- Potential problems due to aqueous corrosion due to low levels of \( \text{H}_2\text{S} \) and water
- Corrosion Under Insulation (CUI) in marine environment and in Gulf coastline (hurricane) affects potentially 75% of piping
Link to Inspection Database

- Establish basis for linking and sharing data between API RBI and IDBMS program
  - Unit identifier
  - Equipment/Pipe identifier
  - Component/Pipe identifier
- TML Number identifier
- TML Location/Type (shell, pipe, elbow, tee, nozzle, vertical, horizontal)
Inspection Interval

- Half Life inspection due date – Inspection database program based on wall loss from previous inspection date
- RBI due date – Risk based date for inspection based on Risk Target
- Jurisdiction – Inspection based on fixed interval from last inspection
TML/CML INSPECTION PROGRAM

RBI ASSESSMENT

RBI ASSESSMENT DATA

PLAN RBI INSPECTION ACTIVITIES

DOCUMENT INSPECTION & RESULTS

INSPECTION PLANNING

INSPECTION RECOMMENDATIONS

Consequence Category

Risk Rank - Low Medium Medium High

Bold Outline Boxes indicate Target Risk
Measured corrosion rates and measured thickness by circuit.
### API RBI Inspection Planning

**Inspection Plan Option:** PLAN  
**Component:** 10-03-05-14

#### Input Inspection Plan parameters

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<tr>
<th>Parameter</th>
<th>Value</th>
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<tr>
<td>Inspection Plan Date (yyyy-mm-dd)</td>
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<tr>
<td>Inspection Plan Basis</td>
<td>AREA</td>
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<tr>
<td>Area Risk Target (ft²/yr)</td>
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<td>Financial Risk Target ($/year)</td>
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<tr>
<td>Max Inspection Interval (yrs)</td>
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<tr>
<td>DF Target</td>
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#### Calculated Inspection Plan

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<th>Number</th>
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<tr>
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<td>2006-05-01</td>
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<tr>
<td>External Damage</td>
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<tr>
<td>HTHA</td>
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</table>

#### Calculated Risk Results

<table>
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<tr>
<th>Risk Category</th>
<th>Date (yyyy-mm-dd)</th>
<th>Target Date Without Inspection</th>
<th>Plan Date Without Inspection</th>
<th>Plan Date With Inspection</th>
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<tr>
<td>Years from RBI Date</td>
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<td>External Damage Risk/DF</td>
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<td>Brittle Fracture Risk/DF</td>
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<td>Mechanical Fatigue Risk/DF</td>
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Detailed inspection plans include scope, damage mechanism and recommended inspection effectiveness.

Inspection recommendations and due date.
Record actual inspection effectiveness and measured thickness to be used in Risk determination.

Updated measured corrosion rate also entered in Thinning Module and Risk recalculated for next interval recommendation.
Risk After Inspection

RBI vs. Traditional Inspection Plan
Inspection Results

- Inspection results and findings should be compared to expectations of damage
  - Thinning rate and type (general or localized)
  - Cracking inspection findings – if cracking was found and severity, if found
- Were there any inspection findings that could impact the RBI Assessment?
- Are there any MOC considerations that could impact the Risk Assessment?
- Any new information or findings should be noted and returned to the RBI analysis Team
Piping TML/CML Analysis

- Piping systematized and circuitized based on corrosion circuits
- Pipe line numbers identified on isometric drawings and grouped by assigned systems and circuits
- RBI component name linked to IDBMS program
- Thickness data by circuit evaluated
- Analysis:
  - Average measured corrosion rate by circuit compared to estimated rates in RBI program
  - Statistically evaluated thickness data determine measurement confidence and variability
Piping TML/CML Analysis

• Data from IDBMS program grouped by RBI defined system and circuits

• Analysis of thickness measurement data by:
  – Equipment thickness data
    + Remove fabrication type and specific flow conditions that might increase variability
  – Component thickness data
    + Evaluate diameter (thickness) contribution to measurement variability
    + Remove fabrication type and specific flow conditions that might increase variability
    + Evaluate diameter (thickness) contribution to measurement variability
Piping TML/CML Analysis Example
Piping TML/CML Analysis Example
Piping TML/CML Analysis Example
Piping TML/CML Analysis

- High data variability can be an indication of higher than expected corrosion rates and/or localized corrosion
- Data from TML measurements show a wide range of wall loss over time
  - +/- 0.02 considered good data
  - +/- 0.08 average data
  - > +/- 0.10 considered poor quality data
- High TML data variation can mask indications of localized thinning
Piping Program Benefits

- Groups components (i.e., circuits) where active damage mechanisms and damage rates are similar
- Allows comparison of measured data and corrosion rates with historical or expected rates as well as localized behavior
- Provides information for defining appropriate coverage of CML/TML as well as other more appropriate inspection methods
- May identify undetected or localized corrosion issues that exist
- Calculates Risk and recommends inspection at circuit level
- Identifies and documents:
  - Multiple potential damage mechanisms
  - Special inspection needs (such as deadlegs, mix points or high risk equipment)
  - Process treatment and monitoring programs, chemical injection, water wash and fouling, etc.
TML/CML Analysis Conclusions

• User must consider:
  – Inherent thickness measurement error with or without a qualified procedure
  – Expected wall loss rate being measured (compared to UT accuracy)
  – Inspection intervals for wall loss detection

• Improved quality and accuracy of thickness measurements are needed to improve analysis capability

• Criteria provided to inspectors before field measurements are taken could significantly improve data quality

• More analysis and trending is necessary to understand the data and define requirements for improving TML inspection quality