PSM - Refining Damage Mechanisms “101”

Jim Riley

New PSM Section §5189.1 subsection (k) - Damage Mechanism Reviews
DMR Requirements

1. Complete a DMR for all existing and new process where DMR exists.
2. Timeline: 50% DMR’s within 3 years, complete all DMR’s within 5 years
3. Revalidation: At least once every five years
4. DMR’s reviewed as part of major process change prior to the change.
5. Where a DMR is a factor in an incident investigation, review most recent DMR’s; if no DMR then recommend a DMR be conducted.
6. DMR’s must be available to team performing a PHA for that process
7. DMR’s performed by team with expertise in engineering, equipment and pipe inspection, damage and failure mechanisms, and operations.
8. A DMR for each process shall include:
A. Assessment of process flow diagrams;
B. Identification of all potential damage mechanisms;
C. Determination that the materials of construction are appropriate for their application and are resistant to potential damage mechanisms;
D. Methods to prevent or mitigate damage; and,
E. Review of operating parameters to identify operating conditions that could accelerate or otherwise worsen damage, or that could minimize or eliminate damage.
9. Damage Mechanisms include:
   A. Mechanical loading failures, such as ductile fracture, brittle fracture, mechanical fracture and buckling;
   B. Erosion, such as abrasive wear, adhesive wear and fretting,
   C. Corrosion, such as uniform corrosion, localized corrosion and pitting;
   D. Thermal-related failures, such as creep, metallurgical transformation and thermal fatigue;
   E. Cracking, such as stress-corrosion cracking; and,
   F. Embrittlement, such as high-temperature hydrogen attack.
10. DMRs shall include an assessment of previous experience with the process, including the inspection history and all damage mechanism data; a review of industry-wide experience with the process; and all applicable standards, codes, and practices.

11. At the conclusion of the analysis, the team shall prepare a written DMR report, which shall include the following:

A. The process unit and damage mechanisms analysed;
B. Results of all analyses conducted, pursuant to subsection (k)(8);
C. Recommendations for temporarily mitigating damage; and,
D. Recommendations for preventing damage.
12. The report shall be provided to and, upon request, reviewed with employees whose work assignments are within the process unit described in the DMR.

13. The employer shall implement all recommendations in accordance with subsection (x).

14. DMR reports shall be retained for the life of the process unit.
Industry Aids Available

- NBIC Part 2 Section 3 Corrosion and Failure Mechanisms (2017 Edition)
- API 580/581 Risk Based Inspection/RBI Technology BRD
- API 584 Integrity Operating Window (1st Edition 2014)
- API 970 Corrosion Control Documents (Draft)
## Damage Mechanisms

<table>
<thead>
<tr>
<th>Damage Mechanism No.</th>
<th>Description</th>
<th>Damage Mechanism No.</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Sulfidation</td>
<td>36</td>
<td>Sulfuric Acid Corrosion</td>
</tr>
<tr>
<td>2</td>
<td>Wet H2S Damage (Blistering/HC/SOH/HCSCC)</td>
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<td>Hydrogen Stress Cracking in HF</td>
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<td>6</td>
<td>Naphthenic Acid Corrosion</td>
<td>41</td>
<td>De-scaling (De-dustification/ Desnicrofication)</td>
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<tr>
<td>7</td>
<td>Ammonium Bisulfide Corrosion</td>
<td>42</td>
<td>CO2 Corrosion</td>
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<tr>
<td>8</td>
<td>Ammonium Chloride Corrosion</td>
<td>43</td>
<td>Corrosion Fatigue</td>
</tr>
<tr>
<td>9</td>
<td>HCL Corrosion</td>
<td>44</td>
<td>Fuel Ash Corrosion</td>
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<tr>
<td>10</td>
<td>High Temperature Hydrogen Attack</td>
<td>45</td>
<td>Amine Corrosion</td>
</tr>
<tr>
<td>11</td>
<td>Oxidation</td>
<td>46</td>
<td>Corrosion Under Insulation (CUI)</td>
</tr>
<tr>
<td>12</td>
<td>Thermal Fatigue</td>
<td>47</td>
<td>Atmospheric Corrosion</td>
</tr>
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<td>13</td>
<td>Sour Water Corrosion (acidic)</td>
<td>48</td>
<td>Ammonia Stress Corrosion Cracking</td>
</tr>
<tr>
<td>14</td>
<td>Refractory Damage</td>
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<td>Cooling Water Corrosion</td>
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<tr>
<td>15</td>
<td>Graphitization</td>
<td>50</td>
<td>Boiler Water / Condensate Corrosion</td>
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<tr>
<td>16</td>
<td>Tempered Embrittlement</td>
<td>51</td>
<td>Microbiologically Induced Corrosion (MIC)</td>
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<tr>
<td>17</td>
<td>Decarburization</td>
<td>52</td>
<td>Liquid Metal Embrittlement</td>
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<tr>
<td>18</td>
<td>Caustic Cracking</td>
<td>53</td>
<td>Galvanic Corrosion</td>
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<td>19</td>
<td>Caustic Corrosion</td>
<td>54</td>
<td>Mechanical Fatigue</td>
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<tr>
<td>20</td>
<td>Erosion / Erosion-Corrosion</td>
<td>55</td>
<td>Nitriding</td>
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<td>21</td>
<td>Carbonate SCC</td>
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<td>Vibration-Induced Fatigue</td>
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<td>22</td>
<td>Amine Cracking</td>
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<td>Titanium Hydrinding</td>
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<td>23</td>
<td>Chloride Stress Corrosion Cracking</td>
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<td>Soil Corrosion</td>
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<td>Carbonization</td>
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<td>Metal Dusting</td>
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<td>25</td>
<td>Hydrogen Embrittlement</td>
<td>60</td>
<td>Strain Aging</td>
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<td>26</td>
<td>Thermal Shock</td>
<td>61</td>
<td>Steam Distillation</td>
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<tr>
<td>27</td>
<td>Cavitation</td>
<td>62</td>
<td>Phosphoric Acid Corrosion</td>
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<td>28</td>
<td>Graphitic Corrosion (see De-scaling)</td>
<td>63</td>
<td>Phenol (carboxylic acid) Corrosion</td>
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<tr>
<td>29</td>
<td>Short term Over heating - Stress Rupture</td>
<td>64</td>
<td>Uniform Corrosion</td>
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<td>30</td>
<td>Brittle Fracture</td>
<td>65</td>
<td>Pitting</td>
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<td>31</td>
<td>Sigma Phase Chi Embrittlement</td>
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<td>Underdeposit Corrosion</td>
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<td>32</td>
<td>650°F (475°C) Embrittlement</td>
<td>67</td>
<td>None</td>
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<td>33</td>
<td>Softening (carbonization)</td>
<td>68</td>
<td>Intergranular Corrosion</td>
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<td>34</td>
<td>Softening (Phosphidization)</td>
<td>69</td>
<td>Acetyl Acid/Anhydride Corrosion</td>
</tr>
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Damage Mechanisms of Equipment based on API 571
Integrity Operating Window
API 584

Critical Limit High
Failure occurs quickly

Standard Level High
Failure occurs with sustained Operations

Stable, Reliable, Profitable
Target Range High
Target —— Optimal
Target Range Low
Safe to Operate Indefinitely

Standard Level Low
Failure occurs with sustained Operations

Critical Limit Low
Failure occurs quickly

Courtesy of Shell Global Solutions – Establishing Integrity Operating Windows, Inspector Summit . January 27, 2006 Galveston, TX/
A document that summarizes:

- Unit process description
- Rationale for materials of construction
- Discusses damage mechanisms
- Defines corrosion circuits
- Defines damage mechanisms in each circuit:
  - Includes critical locations
  - Start up and shut down influences
  - Includes predicted (or actual) corrosion rates and environmental cracking tendencies
Corrosion Control Documents

- Process descriptions
- Hazops
- PFD’s
- P&ID’s
- Material and Heat Balance (H&MB)
- Equipment design
- Piping specifications
- Inspection and maintenance history

Courtesy of The Hendrix Group – Corrosion Control Documents Revisited – 2011 API Inspection Summit - David Hendrix presentation
DMR Review Flow

Define Process Limits
- Description of process and oper. modes
- Heat/Material Balance
- PFDs, P&IDs, MSDs
- SME Books

ID Corrosion Circuits
- Equipment and Piping Design, and Operating Conditions
- CVs, Inj./Mix Pts., IOWs, Bypasses
- Corrosion Circuits

ID Damage Mechanisms
- API 571 and Industry Experience
- Corr. & Mat'l Engineer
- Inspection History and Corrosion Rates
- Operating Parameters

Team Review
- Materials resistance
- Methods to prevent or mitigate DM
- Conditions that would accelerate, worsen, minimize or eliminate DM

Written Report
- Rationale for DMs susceptibility in each circuit
- Recommendations to mitigate or prevent damage
- Recommendations to adjust inspection or PM plans
Fixed equipment and piping in a process with:

- Same stream composition
- Similar operating pressure and temperature
  
  \(< 25^\circ F (~13^\circ C)\) difference
  
  \(< 50 (~4\text{ Barg})\) psig difference

- Same materials of construction
- Same phase, (liquid, vapor, etc.)
Corrosion Circuit Attributes

- Circuit numbering system (legend)
- Circuit description
- Materials of construction
- Stream composition
- OP/OT/Phase information
- Corrosion precursors
- Operational upsets influencing corrosion
- Damage mechanisms
- Corrosion rates (predicted or actual)
- Critical areas
- Operating envelopes
- Startup and shutdown considerations
- Typically obtained from H&MB
- Difficult to obtain in refining units
- Small amounts of corrosives might not be listed:
  - Chlorides
  - Injected chemicals
  - Process contaminants or upset OP
- Should review with owner process eng.
Examples of stream constituents that can influence or accelerate corrosion:

- CO₂
- H₂S
- Chlorides
- Acids
- Oxygen
- cyanides
• Location depends on damage mechanism
  • \( \text{CO}_2 \) – High velocity lines, elbows, etc.
  • Chlorides – Condensing, wet-dry, stagnant area, dead legs, etc.
  • Amine SCC – weld HAZ’s
• Up to unit inspector to locate specific areas in circuit on P&ID
1. Process Description

The Crude Unit separates diluted crude feed into the following products:

- diluent naphtha
- combined distillate (mixture of light distillate, heavy distillate, light vacuum gas oil (LVGO), and purge naphtha).
- medium vacuum gas oil (MVGO)
- heavy vacuum gas oil (HVGO)
- vacuum residue

FEED PREHEAT

The feed is preheated by heat exchange with the following streams:

- diluent naphtha
- overhead vapor from the Atmospheric Tower
- light distillate pumparound and product
- heavy distillate pumparound and product
- medium vacuum gas oil pumparound and product
- heavy vacuum gas oil pumparound and product
- vacuum residue
# 2. Corrosion Assessment of Specific Equipment Categories

## 2.1. Crude Preheat Exchangers to the Desalter Inlet

This includes the crude oil downstream of the storage tanks on the feed side of the preheat exchangers up to the Desalter inlet and the associated piping.

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Material</th>
<th>Description</th>
<th>Temp (°F)</th>
<th>Insulation (N·h·ft)</th>
<th>Anticipated Corrosion Rate (mpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Piping</td>
<td>CS+0.083</td>
<td>Crude feed piping from battery limit to 10-E-001A/B/C</td>
<td>101</td>
<td>N</td>
<td>&lt;5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Crude feed piping to 10-E-002A through J</td>
<td>101</td>
<td>N</td>
<td>&lt;5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Crude feed piping to 10-E-004A/B/C</td>
<td>101</td>
<td>N</td>
<td>&lt;5</td>
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<tr>
<td></td>
<td></td>
<td>Crude feed piping to 10-E-005</td>
<td>210</td>
<td>lh</td>
<td>&lt;5</td>
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<tr>
<td></td>
<td></td>
<td>Crude feed piping to 10-E-005A/B/C/D</td>
<td>215</td>
<td>lh</td>
<td>&lt;5</td>
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<tr>
<td></td>
<td></td>
<td>Crude feed piping to 10-E-007A/B/C/D</td>
<td>215</td>
<td>lh</td>
<td>&lt;5</td>
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<td></td>
<td></td>
<td>Heated feed piping to 10-E-005</td>
<td>254</td>
<td>lh</td>
<td>&lt;5</td>
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<td></td>
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<td>Heated feed piping to 10-E-009</td>
<td>273</td>
<td>lh</td>
<td>&lt;5</td>
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<td></td>
<td></td>
<td>Heated feed piping to 10-E-010</td>
<td>285</td>
<td>lh</td>
<td>&lt;5</td>
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<td></td>
<td></td>
<td>Heated feed piping to Desalter inlet</td>
<td>307</td>
<td>lh</td>
<td>&lt;5</td>
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<tr>
<td></td>
<td></td>
<td>Demulsifier chemical piping from 10-ME-003-TK-1 to injection points</td>
<td>98</td>
<td>N</td>
<td>&lt;5</td>
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<tr>
<td>10-ME-003-TK-1</td>
<td>Vendor Package</td>
<td>Demulsifier Tank</td>
<td>98</td>
<td>N</td>
<td>&lt;5</td>
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<tr>
<td>10-ME-003-P1A/B</td>
<td>Vendor Package</td>
<td>Demulsifier Injection Pumps</td>
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<td>Injection Point</td>
<td>CS+0.063</td>
<td>Demulsifier chemical injection at HC-10-1003-J31D-20&quot;-N</td>
<td>101</td>
<td>N</td>
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<td>Injection Point</td>
<td>CS+0.083</td>
<td>Demulsifier chemical injection at HC-10-1014-J31D-14&quot;-lh</td>
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<td>Injection Point</td>
<td>CS+0.188</td>
<td>Demulsifier water wash at HC-10-1050-J35A-14&quot;-lh</td>
<td>307</td>
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<tr>
<td>Injection Point</td>
<td>CS+0.125</td>
<td>Stripped sour water at HC-10-1060-J35A-14&quot;-lh</td>
<td>307</td>
<td>lh</td>
<td>&lt;10</td>
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<tr>
<td>Injection Point</td>
<td>CS+0.125</td>
<td>Stripped sour water at HC-10-1066-J35A-14&quot;-lh</td>
<td>307</td>
<td>lh</td>
<td>&lt;10</td>
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<tr>
<td>10-E-001A/B/C</td>
<td>CS+0.125</td>
<td>shell Feed/Diluent Naphtha Exchangers (shell side)</td>
<td>210</td>
<td>lh</td>
<td>&lt;5</td>
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<tr>
<td>10-E-002A through J</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/Atmospheric Tower Overhead Exchangers (shell side)</td>
<td>101-210</td>
<td>lh</td>
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<td>10-E-004A/B/C</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/MVGO Product Exchangers (shell side)</td>
<td>101-210</td>
<td>lh</td>
<td>&lt;5</td>
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<td>10-E-005</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/Diluent Naphtha Exchanger (shell side)</td>
<td>210-215</td>
<td>lh</td>
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<td>10-E-006A/B/C/D</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/Light Distillate PA Exchangers (shell side)</td>
<td>215-264</td>
<td>lh</td>
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<tr>
<td>10-E-007A/B/C/D</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/MVGO PA and Product Exchangers (shell side)</td>
<td>215-264</td>
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<td>10-E-008</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/Combined Distillate Exchanger (shell side)</td>
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<td>lh</td>
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<tr>
<td>10-E-009</td>
<td>CS+0.125</td>
<td>shell CS tubes Feed/HVGO Product Exchanger (shell side)</td>
<td>273-285</td>
<td>lh</td>
<td>&lt;5</td>
</tr>
</tbody>
</table>
Specific Corrosion Concerns:

- Possible accelerated corrosion at the injection points where demulsifier chemical, desalter water and stripped sour water are injected into the crude oil feed. Consider the development of an injection point inspection program, using ultrasonic scanning and radiographic techniques, as discussed in API 570 and Inspection Strategy #20.

- Possible corrosion under insulation, for insulated piping and exchanger vessels with a process temperature less than 300°F. Consider a program for CUI inspection, as described in API 570 and Inspection Strategy #19.

- Possible wet H₂S cracking of heat exchanger shells and carbon steel piping. In general, none of the equipment has been PWHT. Exchanger and piping components are at low risk for sulfide stress cracking; however, other forms of long term cracking such as HIC and SOHIC would still apply. Consider prioritization and ultrasonic inspection strategies, as described in Inspection Strategy #17.
3. Process Control Monitoring and the development of Key Critical Operating Parameters

Process Control Monitoring is important to pressure equipment integrity, as well as product quality and production rates. The Key Critical Operating Parameters are those process operating limits that will significantly influence corrosion and other material degradation mechanisms in the Unit. They are listed in this Risk Assessment for guidance only. These operating limits should be established after the Unit is in operation as a joint exercise between the Corrosion Engineer, Unit Operations and the Unit Process Engineer. Where limits apply to the injection of chemicals, (i.e. neutralizing amine or corrosion inhibitor), then the chemical treating specialist should also be included in determining these parameters. Where appropriate, typical limits used in industry have been provided, for reference.

3.1. Crude Preheat Exchangers to the Desalter Inlet

Monitor for:
- Salt content of crude oil (measured by double extraction)
- Sulfur content of crude oil
- Acid content of crude oil
Damage Mechanism Reviews

The Damage Mechanism Review will become an important part of a mechanical integrity program.

Results can be incorporated into validation of Integrity Operating Window programs, Circuitization of equipment and piping for corrosion monitoring and locations for CMLs.

DMRs may be useful with RBI programs and special emphasis inspections.

There are many ways that DMRs can be formatted to accomplish the end goal of defining damage mechanisms and presenting the rational for active DMs, capturing the review by the DMR Team, and the final improvement plans for inspection and PMs.