Combatting HCl Acid-dewpoint Corrosion

• Geysers steamfield overview
• Corrosion failures in high volatile HCl wells
• Monitoring for HCl corrosive conditions
• Strategies to combat HCl corrosion
• Innovations to combat HCl acid-dewpoint corrosion
• Ongoing HCl acid-dewpoint corrosion challenges
The Geysers Geothermal Field

SONOMA -- Unit 3
Steam Piping at The Geysers
Geysers Steam Piping

• B31.1 Power Piping Code
• Carbon Steel
  – Piping – A53 GrB or API 5L GrB
  – Seamless, SAWL (DSAW), ERW
• 333 steam wells. Interconnected piping network
• Over 75 miles of steam piping. 8” through 48”
• No corrosion allowance in legacy piping
  – 3/16 to 1/4-inch effective corrosion allowance
WALL THICKNESS REQUIREMENTS FOR STEAM PIPELINES

Per ANSI/ASME Power Piping Code B31.1 for A53-B Steel

LEGEND

- Pipe sizes used for main steam
- Pipe sizes used for well tie-ins and vent lines

- Rockcatcher Body

Min. Thickness @ 450 psig

Min. Thickness @ 200 psig (Typical Operating Pressure)

Min. Thickness @ 130 psig

Pipe Outside Diameter, Inches

Pipewall Thickness, Inches

J. R. FARISON
MAR 2 1988
Characterizing the Corrosion Environment

• T, P, Saturated versus superheat.
• Bulk fluid vs films and surface chemistry.
• CO2, H2S, NH3, H2, Boron – reducing chemical environment.
• CS forms semi-protective corrosion product layer
• Mix of Iron oxides, Fe3O4 and Iron sulfides, FeS & Fe2S
• Hydrochloric acid. H+ dissolves scale. Cl- disrupts corrosion product layers.
• “Black powder”. FeS. Pyrhotite. Pyrophoric.
HCl Acid-dewpoint Corrosion

• Trace volatile HCl in superheated steam
• Very low pH condensate films
  – Underinsulated areas or “heat fins”
  – Uninsulated piping or equipment
• Severe corrosion rates in carbon steel
  – CR, mpy = 12 x HCl concentration in ppmw
Steam Well & Pipeline Corrosion Challenges

- **HCl Acid-dewpoint corrosion**
  - very corrosive at initial point of HCl condensation
  - HCl dewpoint occurs above T-sat
  - Dewpoint temp is function of [Volatile HCl, ppmw]

- **Current Steam System Corrosion Mitigation Scheme**
  - Based on steady state flows
  - Continuous caustic scrubbing of very high HCl steam wells
  - Maximizing superheat to avoid wellbore corrosion
  - Dilution of high chloride steam with adjacent wells
  - Continuous desuperheating/steam scrubbing of main steam
Manual UT Monitoring

- UT monitoring to assure piping integrity & safety
  - Assure piping > T-min
  - Monitor corrosion rates
- Ultrasonic sensors fail with high temperature
- Time consuming and tedious manual UT
- Remove & replace insulation
- Manual data collection, transfer to PC and creating time plots

Exposed casing below master valve
Wall Thickness & Corrosion Monitoring

Waveguide UT monitoring over DCS network

Manual ultrasonic thickness readings
EXPOSED CASING EVALUATION

WILLIAM CAST #2
Diameter: 11.75 inches

Cal State 92-6
Cal State 92-6 Exposed Casing UT

06-03-2009
Cal State 92-6 Exposed Casing UT

03-28-2011
Rise in Volatile HCl causing casing corrosion

Correlation of wall loss with chloride content over time
High HCl problem wells

STEAM WELLHEAD CHLORIDES in Non-CMF Wells
As ppmw HCl in SH steam

15 wells: HCl > 1.5 ppmw
29 wells: HCl > 1.0 ppmw

102 wells
1.0 > HCl > 0.1

182 wells
0.1 > HCl > 0.03

0.03 ppmw Detection Limit
150 ppmb (SH) Target Max Limit
313 Non-CMF
<table>
<thead>
<tr>
<th>Wellname</th>
<th>Chloride mg/l</th>
<th>UNIT</th>
<th>Wellname</th>
<th>Chloride mg/l</th>
<th>UNIT</th>
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<tbody>
<tr>
<td>GDCF63A29</td>
<td>8.33</td>
<td>Unit 20</td>
<td>GDCF14A27</td>
<td>1.43</td>
<td>Unit 18</td>
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<tr>
<td>GDCF15A28</td>
<td>3.41</td>
<td>Unit 20</td>
<td>GDCF1427</td>
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<tr>
<td>GDCF44A28</td>
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<tr>
<td>GDCF15D28</td>
<td>2.55</td>
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<td>TOCH4</td>
<td>0.46</td>
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<tr>
<td>GDC21</td>
<td>2.48</td>
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<td>MOD1</td>
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<td>Unit 20</td>
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<tr>
<td>GDCF15B28</td>
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<td>Unit 20</td>
<td>MOD2</td>
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<tr>
<td>GDC29</td>
<td>1.25</td>
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<td>DV16</td>
<td>0.28</td>
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<tr>
<td>GDCF3628</td>
<td>0.97</td>
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<td>BGL2</td>
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<td>MOD3</td>
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<td>GDCF4428</td>
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<td>BEF85A28</td>
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<td>GDC23</td>
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<td>BEF42B33</td>
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### Geysers Steam Wells - HCl content

<table>
<thead>
<tr>
<th>Volatile Chloride in SH Steam</th>
<th>Volatile HCl as Chloride ppmw in SH Steam</th>
<th>Acid-Dewpoint in degF SH</th>
<th>Estimated CS Corrosion Rate w/o CMF mpy</th>
<th>Estimated Service Life CS Piping yrs</th>
<th>No. of wells in this chloride range</th>
<th>Percent of wells in each category</th>
<th>Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very Low</td>
<td>0.05</td>
<td>55</td>
<td>10</td>
<td>4</td>
<td>30</td>
<td>10%</td>
<td>Safe to Cutback Dilution steam for High Cl Wells</td>
</tr>
<tr>
<td>Low</td>
<td>0.1</td>
<td>51</td>
<td>5</td>
<td>44</td>
<td>3</td>
<td>10%</td>
<td>Problem Wells Require High SH</td>
</tr>
<tr>
<td>Low Moderate</td>
<td>0.5</td>
<td>51</td>
<td>5</td>
<td>44</td>
<td>3</td>
<td>10%</td>
<td>Problem Wells Require High SH</td>
</tr>
<tr>
<td>High Moderate</td>
<td>1.5</td>
<td>51</td>
<td>5</td>
<td>44</td>
<td>3</td>
<td>10%</td>
<td>Problem Wells Require High SH</td>
</tr>
<tr>
<td>High</td>
<td>5.1</td>
<td>51</td>
<td>5</td>
<td>44</td>
<td>3</td>
<td>10%</td>
<td>CMF Wells Continuous NaOH Scrubbing 1 hour shut-in</td>
</tr>
<tr>
<td>Very High</td>
<td>16</td>
<td>51</td>
<td>5</td>
<td>44</td>
<td>3</td>
<td>10%</td>
<td>CMF Wells Continuous NaOH Scrubbing 1 hour shut-in</td>
</tr>
</tbody>
</table>

- **Acid-dewpoint rises with Chloride ppmw**
- **Target corrosion rate < 10 mils/yr**

**Low Chloride wells can be curtailed, but are required for HCl dilution in the pipeline.**

**Moderate Chloride wells are the focus of field management strategy. Want to balance avoidance of downhole corrosion with management of surface flow of Chlorides in the pipeline.**

**High Chloride wells all have corrosion mitigation with continuous caustic scrubbing and are maintained at full flow.**
Chloride vs. Superheat -- Observed Corrosion Regimes

- **Severe Corrosion**
  - CR = > 100 mpy
  - Caustic Scrubbing
  - CMF Required

- **Severe attack at heat fins**

- **Moderate Corrosion**
  - CR = 1 to 40 mpy

- **Moderate attack at heat fins**

- **Little to no general Corrosion**
  - CR = 1 to 5 mpy

- **Scrubbed steam d/s of CMF**

- **Saturated Steam with < 150 ppbw Chloride after desuperheat system**

- **Suphpt above acid dew-point. Little to no observed corrosion except during transient conditions.**

- **> 40 deg SH Rule-of-Thumb avoids general corrosion**
  - (May lead to deferred corrosion until point of Initial condensation)
Corrosion Mitigation Approaches

• **Feed the corrodents**
  Repair/replace as wall thickness reaches retirement or localized leaks frequency is unacceptable. Primary challenges: Keeping it safe and high costs.

• **Resistant Materials**

• **Tame the Environment**
  Try to maintain high superheat all the way to the powerplant
  Treat the steam to alter the steam chemistry.
  Desuperheating/steam scrubbing with pH 9 steam condensate
  Caustic scrubbing or corrosion inhibitors
Taming Corrosive Steam

- Residual Cl- wash
- MEA as steamline corrosion inhibitor
- Severe HCl acid-dewpoint corrosion
- Scrubbing with NaOH
Desuperheating / Steam Scrubbing

- **Unit 14 Main Pipeline Separator Inspection** – The U14 main pipeline separator was internally inspected on 5-30-12 during the overhaul after a ten year run. Unit 14 had the very first continuous desuperheating system at The Geysers that started up in March 1983. This vessel has now operated with continuous desuperheating for about 29 years. The vessel has original wall thicknesses and internal surfaces of the vessel have a polished appearance. Surfaces are remarkably clean with minimal scale or corrosion debris. Original weld beads are visible and the end edges of spin vanes and the internal downcomer have sharp edges with original dimensions.

**U14 Separator Portatest G84**

Installed 1980

Continuous desuperheating for >30 years

Carbon steel vessel with magnetite protective scale
Sonoma main pipeline separator
Porta-test G72 Recycling
Severe Corrosion from Oxygen in Scrub Water

- Recycle gap area destroyed
- Large hole at inlet pipe
- ½-inch thick spin vanes destroyed
- Portatest G72 42” inlet & outlet

U3 Main Pipeline Separator
- Hotwell water contaminated with O$_2$ from CT water
- U3 Hotwell water used across Geysers during U17 OH in 2009
- U3 vessel replaced in 2010
- Over $1m damage to repair vessels at U5,6,7,8,12.
Material Testing and Selection

Titanium WH Tee

Inconel Thermal Arc Spray

2205 Super Nipple

Alloy CMF Injection Spool

Chloride SCC of Duplex SS
HCl Acid-dewpoint Corrosion Mitigation

- Corrosion Mitigation Facility (CMF) at wellhead piping for very high Cl- wells
- Maintain high superheat to the power plant
- Desuperheating / steam scrubbing systems
- Neutralizing amines for heat-fin corrosion
- ALLOY UP
Heat Fins - Knockout Pots, pipe support shoes

<table>
<thead>
<tr>
<th></th>
<th>Point 1</th>
<th>Point 2</th>
<th>Point 3</th>
</tr>
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<tbody>
<tr>
<td>Emiss.</td>
<td>0.95</td>
<td>0.95</td>
<td>0.95</td>
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<tr>
<td>Avg F</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Min °F</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max °F</td>
<td>62.2</td>
<td>266.0</td>
<td>241.1</td>
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<tr>
<td>Delta °F</td>
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<td>203.8</td>
<td>178.9</td>
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</table>
Corrosion Mitigation Facility (CMF) on High HCl Wells

- Scrub HCl with NaOH + hotwell water
- Successfully used for over 25 years
- 13 CMF wells currently in operation
- Daily checks by Operations
- Weekly Chem Tech checks & efficiency tests
# Summary of CMF Wells

<table>
<thead>
<tr>
<th>Aidlin</th>
<th>Former CMF Wells</th>
</tr>
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<tbody>
<tr>
<td>Aidlin-4</td>
<td>DX-26</td>
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<tr>
<td>Aidlin-7</td>
<td>GDC72-30</td>
</tr>
<tr>
<td>Aidlin-6</td>
<td>SB-25</td>
</tr>
<tr>
<td>Aidlin-9</td>
<td>GGC-4</td>
</tr>
<tr>
<td>Aidlin-1&amp;10</td>
<td>GGC-5</td>
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<td>CAST92-6</td>
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<table>
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<th>Ottoboni Ridge</th>
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<tbody>
<tr>
<td>ABRIL-2</td>
<td></td>
</tr>
<tr>
<td>HBS-1 (plugged)</td>
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<td>OF48-2</td>
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<table>
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<tr>
<td>PS-10 and PS-12</td>
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<tr>
<td>P-4 and P-5</td>
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<tr>
<td>P-25</td>
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<tr>
<td>PS-31</td>
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<table>
<thead>
<tr>
<th>Former CMF Wells</th>
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<tbody>
<tr>
<td></td>
<td>LESP-2</td>
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<tr>
<td></td>
<td>NEGU-15</td>
</tr>
<tr>
<td></td>
<td>GDHS-9</td>
</tr>
</tbody>
</table>

- **CTI**
- **Shut-in**
- **P&A**
Continuous Caustic Scrubbing High HCl Wells
Continuous Caustic Scrubbing High HCl Wells
Automated remote UT Monitoring

- Waveguide UT sensors
  - Dry-coupled to pipe wall
  - Battery operated
  - Cell phone data transfer
- Gateway to network
  - Serial port server
  - System module
  - Power supplies
- DSL over existing DCS
- Software on Network
Corrosion Mitigation in the Northwest Geysers

- **Prati State-31 steam well corrosion mitigation**
  - Corrosion leak occurred due to severe HCl acid-dewpoint corrosion just below wellhead on 2-13-13 after only 70 days of initial steam production
  - Duplex stainless 2507 alloy seam-welded casing selected
  - 4,000 feet of 8-5/8” and 7-5/8” alloy casing
Ongoing HCl Acid-Dewpoint Corrosion Challenges

- Avoiding wellbore condensation and in high volatile HCl wells
- Maintaining efficient scrubbing process in high HCl wells
- Monitoring for corrosion and changing conditions.
- Removing corrosion debris fines. 1-5 micron particles.
- Under deposit corrosion
- Avoiding dissolved oxygen in scrub water
- Separator carryover. Removal of high residual Cl condensates.
- Mixing point corrosion. Mixing SH high HCl steam with wet steam.
- Dewatering wells to avoid wellbore heat losses & casing corrosion
Thank you!
Any questions?