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Near Surface External Casing Corrosion; 
Cause, Remediation and Mitigation

Jerry Dethlefs
ConocoPhillips Company
Agenda

• Problem Description

• Corrosion Mechanism

• Repair Process
  – Excavation
  – Patch

• Mitigation Process
  – Sealant

• Summary and Conclusions
Kuparuk Operations

- Approximately 1200 wells
- Field startup in 1981
- First Surface Casing (SC) corrosion noted in 2000
- By 2005 over 25 wells with SC leaks
The Problem

• Escalating rate of SC failures
  – Holes near surface from 0 to 25’+
  – Detected by leaks at surface

• SC is a well barrier
  – Well integrity issues
  – Production impacts

• What is the cause and long term cost impact?
Surface Casing Corrosion
Investigation

SC corrosion NOT related to:

- Age of well
- Electrical stray currents
- Surface location

• There ARE correlations with:
  - Design
    • Number of casing strings
  - Type of service
    • Temperature correlation
Findings

• Conducted field tests with corrosion consultant

• **Root cause**: Primary cement procedure combined with Arctic cement blends

Mechanism:

• Repeated wetting of cement with oxygenated water
• Cement breakdown = corrosive fluid
• Add heat from production
• Galvanic and thermo-galvanic cells
• SC becomes sacrificial anode
• Conductor becomes cathode
Corrosive Fluid

Oxygenated water becomes an electrolyte in the annulus due to components of degraded cement.

Electrolyte Resistivity: The lower the resistance value, the easier it conducts electricity and is more corrosive.

<table>
<thead>
<tr>
<th>Resistivity (Ohm-cm)</th>
<th>General Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 500</td>
<td>Extremely Corrosive</td>
</tr>
<tr>
<td>501-1,000</td>
<td>Very Corrosive</td>
</tr>
<tr>
<td>1,001-5,000</td>
<td>Corrosive</td>
</tr>
<tr>
<td>5,001-10,000</td>
<td>Moderate-Mildly Corrosive</td>
</tr>
<tr>
<td>Above-10,000</td>
<td>Normally not significant</td>
</tr>
</tbody>
</table>

Source: Farwest Corrosion Control Report 6731, J. Bollinger
Test Samples From One Well

<table>
<thead>
<tr>
<th>Material &amp; Source</th>
<th>Resistivity</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cellar Water</td>
<td>1,020</td>
<td>Corrosive</td>
</tr>
<tr>
<td>Cement (Dry)</td>
<td>400,000</td>
<td>Not significant</td>
</tr>
<tr>
<td><strong>Cement (Saturated)</strong></td>
<td><strong>38</strong></td>
<td><strong>Extremely Corrosive</strong></td>
</tr>
<tr>
<td>Soil Adjacent cellar (Dry)</td>
<td>58,000</td>
<td>Not significant</td>
</tr>
<tr>
<td>Soil Adjacent cellar (Sat)</td>
<td>3,700</td>
<td>Corrosive</td>
</tr>
</tbody>
</table>

Source: Farwest Corrosion Control Report 6731 J. Bollinger
Well Construction

- Surface Casing, ~2,500’ TVD, Cemented to surface
- Conductor @ 120’ RKB, Cemented to surface
- Cemented to surface

Cement fallback
- Fluid losses
- Fracture zones
- Voids
- 0’ to > 100’

Arctic Set cement
15% Salt and Gypsum
Galvanic Cell in Annulus
(Cross Section)

Corrosive water in annulus

Electrons

Oxidation

Reduction

Salt Bridge
(Cement Additives)

Primary cement top

Surface Casing

Conductor

High Temp

Low Temp

Corrosion

Anode
(Surface Casing)

GALVANIC CELL

Cathode
(Conductor Casing)
Heat Increases Corrosion Rate

Single Casing Completion with Hot Water Injection*
• One less annulus to insulate from permafrost
• Higher Temperature Gradient = Faster Thermo-Galvanic Corrosion

Thermo-Galvanic Corrosion
• Caused by thermal gradient
• Similar effect as galvanic corrosion
• Anodic and cathodic areas are formed
• Corrosion attack will develop

*‘A’ annulus and conductor; no ‘B’ annulus

Source: Farwest Corrosion Control Report 6731, J. Bollinger
Primary Cement Blend

Surface Casing Cement
- Good cement minimizes corrosion
- Light weight cement to reduce hydrostatic head
- Designed to set prior to freezing in permafrost zone

Additives = Complications
- +/- 15% Salt for Freeze Point Depression
  - Salt Water = Higher Corrosion Rates
- Gypsum for Heat of Hydration
  - Gypsum = Plaster of Paris
    - Degrades Rapidly in Water
- Lead slurry contaminated during displacement
To Initiate Corrosion:

Just add oxygenated water from snow melt or rain--
And repeat year after year!

Water Level Marks in Culvert

Oxygen Enriching Algae in Water
Remediation Process

• Excavation
• Preparation
• Patch

Important:
– Perform risk assessment
– Wells require safe-out
– Follow HSE guidelines
Excavation Methods

Shallow – Vacuum Removal
Excavation Methods

Moderate – Backhoe & Scaffold
Excavation Methods
Deep – Backhoe & Trench Box
Multiple Well Excavation
Current Approach

- Minimal cellar
- Up to 8’ deep
- Low cost option
Conductor Removal Methods

Torch
Conductor Removal Methods

Casing Window Cutter
Cement Sheath Removal

Conductor
Shallow Repair Sequence

- Buff or sandblast SC
- Ultrasonic Thickness (UT) inspection
- Engineered patch
Shallow Repair Sequence

Install SC sleeve – typically split casing
Shallow Repair Sequence

Sleeve installed and welded
Shallow Repair Sequence

Corrosion protection installed over sleeve
Shallow Repair Sequence

Re-install Conductor
Fill with cement and top with sealant
Corrosion Mitigation Process

• Existing wells:
  – Seal water entrance paths
    • Weld or plug conductor holes
    • Top-fill with cement to near surface
    • Top with dielectric sealant

• New wells - Drilling
  – Improve cementing practice
    • Cement to near surface
    • Top with dielectric sealant
Job of Sealants

- Seal annulus from water and oxygen
  - Even if completely submersed
- Suitable for wide temperature fluctuations
- Environmentally benign
- Should be removable
- Should remain in place
  - No “Projectile” with deeper Leak
- Should be replenishable
Sealant Properties

• “Grease-like” product
• Dielectric properties
• Non hardening co-polymer
• Excellent corrosion performance
• Provides protective film
• Densified with zinc dust
  – Heavier than water
• Best performance
Treatment Temperature

- Sealant 115 to 130 F
- Will not burn workers
- Sufficient to self level
- Will not overflow when at operating temperature
Treatment Overview

SC ~ 2,500’ TVD

Top with sealant
(1-2’ typical)
Raise cement top
“Top Job” with hose & low pressure pump

Cement fallback
- Fluid losses
- Fracture zones
- Voids
What Sealant Looks Like
Project Status

As of July 2010:
- 56 casing failures known or suspected
- 45 excavations and patches completed
- 1133 wells sealant treated
Patch Economics

- Cost < 6% of rig workover repairs
- Savings > $65,000,000
  - Over 8-year period compared to using rotary rig
  - Assuming 50% of wells were “economic” to repair
- More wells remain in service due to robust patch economics
Sealant Mitigation

- Treat remaining wells in Kuparuk and satellite fields
- New wells treated after release by Drilling
- Other North Slope Operators adopting program
- Applicable in many global locations
Conclusion

• SC corrosion cause identified

• SC repairs on-going

• Mitigation in progress

• Improved cement procedures for new wells

• A non-traditional, non-rig repair can be a safe, cost-effective alternative
Application

• Offshore locations
  – Saltwater exposure

• Onshore
  – Cement additives
  – Shallow surface water sources
  – Production fluids release
  – Well servicing fluid exposure
Thank you!

Questions?
Based on:
SPE-100432-PP Near Surface Casing Corrosion in Alaska; Cause and Mitigation

Jerry Dethlefs, Curtis Blount, ConocoPhillips and John Bollinger, Farwest Corrosion Company
Contributions by ConocoPhillips Alaska Wells Group

• Published:
  – SPE Drilling & Completion Journal, December 2008, Volume 23, Number 4

• Reference:
  – SPE 50967 Corrosion Problems in Below-Grade Wellhead Equipment and Surface Casings

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  – MJ Loveland and Perry Klein, ConocoPhillips Alaska Wells Group