Other Corrosion Concerns Affecting Life Extension of Light Water Reactors

2016 International LWR Material Reliability Conference and Exhibition
August 1 – 4, 2016
Introduction

- Corrosion is a major life limiting mechanism for LWRs
- Justifiably, most emphasis is placed on environmentally-assisted cracking (EAC) and particularly, stress corrosion cracking (SCC) (e.g., IGSCC, PWSCC and IASCC plus LPSCC, ODSCC and ClSCC)
- However, there are other corrosion phenomena that can also affect plant life extension that cannot be ignored
  - Corrosion of steel containments
  - Flow-accelerated corrosion of carbon steel
  - Corrosion of buried piping
Some Containment Corrosion History

- 1980 – Oyster Creek – Water in sand bed indicates possible corrosion of drywell
- 1992 – Robinson 2 – Discoloration of vertical portion of containment liner at an insulation joint
- 1992 – Beaver Valley 1 – Peeled coating and spots of liner corrosion
- 1993 – Brunswick 1 and 2 – Corrosion of the drywell liner at various spots at the junction of the base floor and the liner
- 1993 – Salem 2 – Minor corrosion of the containment liner
- 1998 – D. C. Cook 1/2 – “pitting” of the containment liner at moisture barrier seal
- 2002 – Davis-Besse – Corrosion at containment floor interface
- 2003 – Surry 2 – Degraded coatings and rust on containment liner at junction of metal liner and interior concrete floor
Some More Containment Corrosion History

- 2008 – Brunswick 1 – Corrosion under wet felt covering primary containment penetration sleeve
- 2007 – Three Mile Island 1 – Corrosion at defective moisture barrier seal between the containment and concrete floor
- 2009 – Beznau – Corrosion on both sides of steel containment below concrete floor
- 2009 – Salem 2 – Corrosion at defective moisture barrier seal between the containment and concrete floor
- 2009 – Beaver Valley 1 – Through-wall containment corrosion under blistered paint and rust due to buried wood in concrete
- 2010 – Turkey Point 3 – Through-wall corrosion of containment sump liner
- 2010 – Koeberg 1 – Wood in concrete
Example of Mark I Containment - Browns Ferry Unit 1 ~1973

- Drywell
- Vent Lines
- Torus
Oyster Creek Drywell History

- Oyster Creek BWR – Start up in 1969
- 1980 refueling outage - water was noted around various containment penetrations and floors
- Intrusion of water into the annular space between the carbon steel drywell shell and concrete shield wall
- Radiological analysis indicated an activity level similar to primary water
- Suggested that the source of the water was the reactor cavity located immediately above the drywell
General Corrosion of Oyster Creek Mark 1 Containment Drywell
Oyster Creek Sand Bed Region

Carbon Steel Drywell Shell

Corrosion Product

1992
Mechanism of Oyster Creek Drywell Corrosion

Concrete floor

O$_2$ rich areas (cathode)

O$_2$ + 2H$_2$O + 4e$^-$ $\rightarrow$ 4OH$^-$

Concrete curb

Sand-covered
O$_2$ depleted areas (anode)

Fe $\rightarrow$ Fe$^{2+}$ + 2e$^-$

High pH concrete

Wet Sand

Drain
Source of Water - First Drywell to Cavity Seal and Reactor Cavity

- Protective Shielding
- Gusset
- Bottom Plate
- Fire Bard Insulation Material
- Drain for Steel Trough (2")
- Drain for Concrete Trough (2")
- Leakage Path
- Stainless Steel Liner
- Refueling Bellows
- Reactor Cavity
- Stainless Steel Liner
- Concrete
- See Detail "B"
- Reactor Vessel
- Drywell and Reactor Cavity Section Detail "A"
Containment Corrosion Mitigation at Oyster Creek

- 1986 – Tried cathodic protection
- Adjacent sand dried out
- Early 1988 – Drain lines cleaned of hardened sand
- 1000s liters (gallons) of water removed from sand bed
- Late 1988 – Initiate sand removal via vacuum hoses and install strippable coating to reactor cavity
- Late 1991 – Remaining 50% of sand removed via 10 500 mm (20 inch) diameter manways
- Late 1991 – Triple part epoxy coatings on drywell
Oyster Creek Drywell Sandbed Bay 11A Thickness Measurements vs. Time

Figure 7. Sandbed Bay #11A

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Thickness</th>
<th>Error</th>
<th>Error Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan '95</td>
<td>29.3 mm</td>
<td>+/- 0.196 mm/y</td>
<td>+/- 0.203 mm/y</td>
</tr>
<tr>
<td>Dec '95</td>
<td>18.7 mm</td>
<td>+/- 0.032 mm/y</td>
<td>+/- 0.036 mm/y</td>
</tr>
</tbody>
</table>

UT locations

Seal

### Example of Containment Moisture Barrier Corrosion

<table>
<thead>
<tr>
<th>Location</th>
<th>Measured Thickness, cm (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5 cm (2&quot;) above floor</td>
<td>0.95 (0.37&quot;)</td>
</tr>
<tr>
<td>3.4 cm (1.3&quot;) above floor</td>
<td>0.88 (0.35&quot;)</td>
</tr>
<tr>
<td>1.7 cm (0.7&quot;) above floor</td>
<td>0.84 (0.33&quot;)</td>
</tr>
<tr>
<td>Floor line</td>
<td>0.66 (0.26&quot;)</td>
</tr>
<tr>
<td>1.3 cm (0.5&quot;) below floor</td>
<td>0.61 (0.24&quot;)</td>
</tr>
<tr>
<td>2.5 cm (1&quot;) below floor</td>
<td>1.01 (0.40&quot;)</td>
</tr>
</tbody>
</table>

Nominal containment thickness = 0.95 cm (0.37")
Paint blister identified during 2009 1R19 IWE inspection

Area beneath the blister contained through-wall penetration ~ 10 x 25 mm (3/8 x 1 inches)

BV-1 Initiated service in 1987

D. Weakland and D. Hecht, 092310
Containment with Local Anodes

D. Dunn, et al., 15th Env. Deg. 2011
Portion of liner plate removed to look at the debris behind the liner plate

No “corrosive agents”
Debris was removed from the concrete creating a void
~5 x 15 x 10 cm (~2 x 6 x 4 inches) deep

Debris:
Wood that >37 years in concrete still had 13% moisture content
\( \text{pH}_{\text{wood}} = 3.5 \)

Repair Activities:
Welded in a new portion of the liner
Pressure tested the area
Volumetric examination of welds
Restored the paint
Example of Under Thermal Shield Containment Liner Corrosion

Insulation sheathing/caulking are not waterproofed against standing water or atmospheric moisture.
Containment Corrosion Summary

- OE shows that containment liner corrosion is often the result of liner plates being in contact with objects and materials that are lodged between or embedded in the containment concrete
  - Organic objects promote accelerated corrosion since they can trap water and cause a localized low pH when they decompose
- Visual inspections typically identifies the corrosion only after it has significantly degraded the liner
  - Corroded areas found by UT of suspect areas (e.g., areas of obvious bulging, hollow sound)
- Foreign objects that enhanced liner corrosion:
  - Foreign material (e.g., wood, workers’ gloves, wire brush handles)
  - Design materials (e.g., felt)
FLOW-ACCELERATED CORROSION
LWR Flow-Accelerated Corrosion (FAC)

- FAC: protective oxide layer on a carbon steel surface dissolves in fast flowing water
- Underlying metal corrodes to re-create the oxide and metal loss continues at a constant rate
- FAC was distinguished from erosion corrosion:
  - FAC does not involve impingement of particles, bubbles or cavitation
  - By contrast to E/C, FAC involves dissolution of normally resistant oxide by combined electrochemical, water chemistry and mass-transfer phenomena
- Rate of metal loss depends on a complex interplay of many parameters including:
  - Dissolved oxygen content and pH
  - Material composition (e.g., minor alloying elements Cr, Cu and Mo)
  - Fluid hydrodynamics (e.g. velocity, geometry, steam quality, temperature and mass transfer)
LWR Flow-accelerated Corrosion History – Surry 2 – 1986

- Surry start up: May 1973
- December 9, 1986: 46 cm (18”) diameter carbon steel condensate system elbow rupture in the secondary side of the Surry 2 PWR kills 4 and severely injures 4
- Surry 2 was the first time “erosion corrosion” in single phase system was observed in a US LWR
- LWR staffs have since included inspections of carbon steel in their ISI programs
- EPRI subsequently develops CHEC™, CHECMATE™ and CHECWORKS™ FAC codes
Surry 2 Condensate Elbow FAC
Déjà vu LWR FAC – Mihama 3 – 2004

• August 9, 2004 (18 years after Surry 2!): 56 cm (22”) carbon steel steam line rupture Mihama 3 PWR kills 5 and severely injures 6 after 28 years of operation
• Kansai Electric Power (Kepco) admitted that it was told in April 2003 that this pipe was “a safety threat”
• The 149ºC (300ºF) steam pipe was only inspected after fitting in 1976 and not examined since because “it was not expected to corrode so quickly”
• Scheduled for re-inspection August 14 (five days after the rupture)
• Kepco admitted that the pipe had dangerously corroded 96% to just 0.4 mm (20 mils) from its original 10 mm (0.39 in) thickness
Mihama 3 FAC

- Kepco spokesman: “We conducted visual inspections, but never made ultrasonic tests, which can measure the thickness of a steel pipe.”

- Deputy plant manager: “We thought we could delay the checks until this month.” “We had never expected such rapid corrosion.”
Partial List of Other Nuclear Plant Failures due to FAC

<table>
<thead>
<tr>
<th>Plant</th>
<th>Event Date (Start Date)</th>
<th>Equipment Consequences</th>
<th>Ruptured Region</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dukovany</td>
<td>2/92 (?/?/?)</td>
<td>Pipe Rupture</td>
<td>Steam extraction line elbow</td>
</tr>
<tr>
<td>Ft. Calhoun</td>
<td>4/97 (8/73)</td>
<td>Pipe Rupture</td>
<td>Condensate elbow</td>
</tr>
<tr>
<td>Point Beach 1</td>
<td>5/99 (10/72)</td>
<td>Feedwater heater shell</td>
<td>Feedwater heater shell</td>
</tr>
<tr>
<td>Maanshan 1 &amp; 2</td>
<td>12/01 (7/84) (5/85)</td>
<td>HP/LP feedwater heater shell</td>
<td>Feedwater heater shell and nozzles</td>
</tr>
<tr>
<td>Bruce 8</td>
<td>2/06 (5/87)</td>
<td>SG tube SP</td>
<td>Steam Generator TSP</td>
</tr>
<tr>
<td>Zaporozhye 4</td>
<td>9/04 (4/88)</td>
<td>Pipe Rupture</td>
<td>Elbow</td>
</tr>
<tr>
<td>Smolensk 2</td>
<td>2/05 (7/85)</td>
<td>Pipe Rupture</td>
<td>Valve</td>
</tr>
<tr>
<td>Clinton</td>
<td>2/05 (4/87)</td>
<td>Holes/Bellows</td>
<td>Extract steam</td>
</tr>
<tr>
<td>South Ukraine 2</td>
<td>7/05 (5/85)</td>
<td>Pipe Rupture</td>
<td>Elbow</td>
</tr>
<tr>
<td>South Ukraine 2</td>
<td>8/05 (5/85)</td>
<td>Pipe Rupture</td>
<td>Elbow</td>
</tr>
<tr>
<td>Smolensk 2</td>
<td>2/06 (7/85)</td>
<td>LP heater rupture</td>
<td>Heater shell</td>
</tr>
</tbody>
</table>

Dukovany, Point Beach 1 and Ft. Calhoun PWR FAC Failures

Dukovany extraction line (1992)

Point Beach 1 feedwater heater shell (1999)

Ft. Calhoun HP extraction line (1997)

W. Ahmed, 4/09
BWR Examples of Two Phase FAC

Flow rate = 72 m/s = 235 ft/s = 160 mph!
FAC of CANDU Steam Generator Support Plates

Example of severe thinning on underside of broached TSP

- Illustrates an advanced stage of FAC
- Thinning is uniform to ~10% remaining ligament

P. King, 12th Env. Deg., 2005
PWR and BWR Examples of Low Temperature FAC

Piping downstream of the condensate polisher at South Texas Project

32 – 54°C (90 – 129°F) and 2.7 m/s (8.8 ft./s) pH 7 and 5 ppb DO

CRD straight pipe downstream of an orifice at Fukushima Daini 1
35°C (95°F) and 1 m/s (3.3 ft./s) <10 ppb DO
FAC Critical Parameters

- Water chemistry
  - pH (<9.3)
  - Dissolved oxygen (<40 ppb)
  - Temperature (maximum at 135°C [275°F] water and 177°C [350°F] steam)

- Material chemistry
  - Cr, Cu or Mo (<0.5%)

- Hydrodynamics
  - Velocity (>4.6 m/s [>15 ft./s] water, >27 m/s [>90 ft./s] steam)
  - Geometry (turbulence in elbows, tees, etc.)
  - Steam Quality (0.1 to 0.9)

P. Sturla, 5th Nat. Feedwater Conf., 1973
Effect of Chromium Content on FAC

Temperature 180 °C (356 °F), pH 9.0,
velocity 56 m · s⁻¹ (183 ft/s),
NH₃ and 20 µg · kg⁻¹ N₂H₄
FAC Susceptible Carbon Steel Systems

• Single Phase
  – Condensate and feedwater
  – Auxiliary feedwater
  – Heater drains
  – Moisture separator drains
  – Reheater drains
  – Lower head drain lines
  – Other drains

• Two Phase
  – High and low pressure extraction steam lines
  – Flashing lines to the condenser (miscellaneous drains)
  – Feedwater heater vents
  – SG blow-down
  – Moisture separator drains
  – Lines with leaking valves
  – Main steam lines
  – Reheat steam lines
Methods to Control FAC in LWRs

- **BWRs**
  - Replace carbon steel with low alloy steel or stainless steel
  - Increase dissolved oxygen content (e.g., >30 ppb)
  - Oxygen (ppb) | Relative FAC
    |           |
    | 10        | 1.00      |
    | 30        | 0.30      |
    | 50        | 0.18      |
    | 100       | 0.11      |
    | 200       | 0.003     

- **PWRs**
  - Replace carbon steel with low alloy steel or stainless steel
  - Increase pH
BURIED PIPING
Buried Pipe Background

• Nuclear sites have 1000s kms (1000s miles) of buried piping
• Continued integrity of buried piping will be a key item to achieving plant design life, especially for license renewal
• Unlike above-ground piping systems, buried pipes have a greater potential to corrode from both the fluid side and from the soil side
• Degradation can be difficult to evaluate since the pipes are difficult to reach for inspection
• When buried pipes leak, the source of leakage can be difficult to locate, access and repair in a timely manner
  – Several plants have experienced costly leaks and repairs of their buried pipes
Nuclear Industry’s Approach

- EPRI’s Buried Pipe Integrity Group (BPIG) and Balance of Plant Corrosion (BOPC) Integration Committee
  - Sponsored “Recommendations for an Effective Program to Control the Degradation of Buried Pipe”
- Nuclear Energy Institute’s (NEI) Nuclear Strategic Issues Advisory Committee (NSIAC)
  - Sponsored three related initiatives:
    - Ground Water Protection Initiative (NEI-07-07)
    - Guideline for the Management of Buried Piping Integrity (NEI-09-14)
    - Coordination of the Enhanced Inspection and Environmental Monitoring Initiatives (NEI 11-07)
- Institute of Nuclear Power Operations (INPO) has provided several related guidelines to their member plants
Common Types of Corrosion Degradation Failures in Buried Piping

• General Corrosion Failures
  – Stress from the applied load (e.g., pressure, dead weight, etc.) exceeds the reduced strength of the component

• Localized Leaks
  – Metal loss at coating damage sites not controlled using cathodic protection
  – Low leak rates that do not impact the ‘intended function’ of the pipe
  – Effect on neighboring equipment or can have environmental effects (e.g., leaks of radionuclides, oil or fuel, loss of support from soil wash-out)

• Occlusion Failures
  – Buildup of corrosion products or tubercles decreases the effective pipe ID and flow-carrying capability of a service water pipe
Complex Buried Piping System

Soil electrolyte also induces stresses on coatings. Backfill will maintain its physical characteristics, but will eventually assume the chemical characteristics of the surrounding soil. The compaction requirements of the backfill can also cause significant coating damage.

Buried piping system goal is pipe wall integrity

Fluid chemistry and flow influence the internal corrosion rate

Ground water level can affect coating life and external corrosion rates

Coating = 1st line of defense against external corrosion. All external coatings have coating damage or holidays and a finite life of ~25 to 30 years.

CP = 2nd line of defense to protect the pipe at coating holidays

System Fluid

DC Source

Anode
Examples of Exterior and Interior General Corrosion of Buried Piping
Example of Collateral Damage from a Small Leak from a Buried Pipe

S. Papavinasam, Corrosion 2011
Occluded Pipe due to Tubercles
Designing Cathodic Protection Systems is Challenging
Summary

• Corrosion emphasis in the nuclear corrosion community has been focused on EAC of LWR structural materials
• However, there are other corrosion phenomena that affect plant life extension that cannot be ignored:
  – General corrosion of steel containments
  – FAC of carbon steel piping
  – Corrosion of buried piping
• All organizations involved with LWR life extension need to have a global approach to all LWR corrosion concerns