

# Nondestructive Evaluation: Operating Experience with Heat Exchanger Tubing Damage

2014 TECHNICAL REPORT

### Nondestructive Evaluation: Operating Experience with Heat Exchanger Tubing Damage

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### **PRODUCT DESCRIPTION**

This report describes the work performed to capture balance-of-plant (BOP) heat exchanger tubing damage operating experiences at nuclear stations.

### Background

Utilities do not have an easy way currently to share operating experience of heat exchanger tube failures. Because of the lack of availability of a common tube failure database to manage a tube bundle integrity program, utilities rely on the plant's own recorded history and consultation with vendors to make inferences on material performance and the effectiveness of inspection programs. Accordingly, it would be beneficial to have access to a database that material performance and inspection programs can be benchmarked against. Indeed, such a database is currently available for other systems at nuclear stations.

### Objective

The objective of the work was to capture operating experience and lessons learned on BOP heat exchangers and to document the information to assist in inferring nondestructive examination (NDE) effectiveness and heat exchanger material performance.

### Approach

To achieve the stated objectives, the project queried the Institute of Nuclear Power Operations (INPO) database as the primary source of heat exchanger events. Once these events were captured, questions were sent to the utilities authoring the reports to obtain supplemental information not provided in the INPO report. In addition, some utilities contributed additional operating experience cases not included in the INPO database.

### Results

The work captured tubing damage operating experience cases in condensers, feedwater heaters, emergency diesel generator heat exchangers, closed cooling water heat exchangers, residual heat removal heat exchangers, and seal oil coolers. Also, some of the cases included a comparison between the NDE evaluations and the corresponding tube laboratory analysis.

The information captured was mapped into six categories for each heat exchanger service: material type, damage mechanism, inspection technique, service life, cleaning and inspection frequency, and plugging criteria.

### Applications, Value, and Use

The information obtained in this work can be used by utilities to benchmark their material performance and inspection information against the experiences reported at other plants. In this report, the information is presented in table form. It is foreseen that, in the future, the captured material will grow and the database will migrate to an online query system with the capability to make parametric comparisons.

Keywords Damage Heat exchanger Leaks Tubing

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# **1** INTRODUCTION

The objective of this work was to capture operating experience (OE) and lessons learned on balance-of-plant (BOP) heat exchanger (HX) tubing damage and document the information to assist in:

- Inferring nondestructive evaluation (NDE) effectiveness and identifying technology gaps
- Inferring HX material performance to assist plants in their tubing selection

# **2** BACKGROUND

Utilities do not have an easy way to share operating experience of HX tube failures. Because of the lack of availability of a common tube failure database to manage a tube bundle integrity program, the HX program manager relies on the plant's own recorded history and on consultation with vendors to make inferences on material performance and the effectiveness of inspection programs. Accordingly, it would be beneficial to utilities to have access to a database that material performance and inspection programs can be benchmarked against. Indeed, such a database is currently available for steam generators, but is lacking for HXs.

A major challenge faced when putting together the skeleton of such a database is that within a nuclear station there is a wide variety of HX services, and within a tube bundle there are several types of tube damage and support plate degradation mechanisms that are present depending on the type of service. This variety creates a wide range of options that are difficult to classify and ultimately optimize.

This report describes the methodology used to classify information related to HX material and inspection operating experiences.

### **3** DATABASE STRUCTURE, CATEGORIES, AND PARAMETERS

In laying out the structure of the database, the first step was to create a vision on how the information is to flow when all the information is in place.

It is envisioned, then, that on one end information is provided on the HX service environment and flow velocity. This information determines the material selection and the corrosion damage morphology.

At the other end, information is provided on the tube failure history. The tube failure history and corrosion damage morphology then determine the inspection technique and implementation frequency.

This flow of information is shown graphically in Figure 3-1. As seen in the figure, distinction is made between damage that originates in the tube's internal diameter (ID), the tube's outside diameter (OD), and the shell side of the HX.



Tube ID

Figure 3-1 Database Flow Diagram

### 3.1 Categories

Using Figure 3-1 as a basis, the following database categories were identified:

- Corrosion environment
- Material type
- Damage mechanism
- Tube cleaning and inspection frequency
- Tube plugging criterion
- Inspection technique
- Tube service life

Information about these categories for the various HX services was then investigated in this work.

Note that the "inspection frequency" and "plugging criterion" were treated as separate categories. In HX inspection, the plugging criterion plays the role of corrosion rate estimation. In other inspection disciplines, such as flow-accelerated corrosion, corrosion rate is calculated from the wall thickness measurement histories obtained from a component at a particular location. Under this methodology, the inspection frequency is calculated by estimating the time when the corrosion process will reduce the remaining wall thickness to a critical value; the next inspection is then scheduled at approximately an interval of one-half of this estimated time. By comparison, for HXs, the program manager selects a plugging criterion value so as to minimize the chance that the tubing might fail between inspections or, in some cases, between outages. If tubing leak histories occur ahead of schedule, the plugging criterion value is modified (reduced) to synchronize the tubing life with the inspection plan. Accordingly, plugging criterion adjustments in HXs play the same role as corrosion rate estimations in other inspection activities.

When searching for HX operating experience information, the author found that "corrosion environment" information was not readily available. Plants collect this information via a variety of techniques including performing periodic sampling and chemical analysis of the water, tracking the corrosion history of metallic coupons, and deploying corrosion rate sensors. Because of the complexity of the task, a database that encompasses corrosion environment information is a subject unto itself, and in the absence of readily available information, the subject was not included in this work.

When capturing the "tube service life" category, it was noticed that tubes that were affected by a single damage mechanism, presumably the one that the material was designed for, exhibited a relatively long life, whereas tubes that were affected by a combination of two or more damage mechanisms had a significantly reduced service life. So when documenting the cases, attention was given to the presence of multiple corrosion processes.

Also, under the "tube service life" category, the survey information could not properly distinguish between time-to-leak and time-to-retube. For a plant, the time-to-retube is the more important economic decision, while from a point of view of inspection frequency, the time-to-leak is the dominant factor.

### 3.2 Heat Exchanger Types

The HXs used in nuclear stations were divided into the following service types:

- Condenser
- Feedwater heater
- Emergency diesel generator
- Closed cooling water HXs
- Residual heat removal HXs
- Seal oil coolers

The emergency diesel generator system includes the intercooler, jacket water, and lube oil HXs.

The closed cooling water system includes the HXs used to remove heat from systems that carry radioactive fluids and are cooled by other systems (that is, service water) that are cooled by water from the ultimate heat sink. In boiling water reactors (BWRs), the system is divided into turbine and reactor cooling systems, whereas in pressurized water reactors (PWRs), no distinction is made.

Seal oil coolers are typically used to remove the heat from lubricating fluids in rotating equipment. These coolers are normally small straight shell and tube HXs with the seal oil on the shell side and cooling water on the tube side.

# **4** HEAT EXCHANGER OE SURVEYS

The project used the INPO database as the primary source of HX events. For this work, events occuring from 2002 to March 2013 were used. Once these events were captured and mapped to the categories listed in Section 3.1, questions were sent to the utilities that had authored the reports to obtain supplemental category information not provided in the OE report.

In summary, 124 OE cases were captured as shown in Table 4-1:

| Heat Exchanger             | OE Events |
|----------------------------|-----------|
| Condenser                  | 38        |
| Feedwater heater           | 25        |
| Emergency diesel generator | 12        |
| Closed cooling water       | 18        |
| Residual heat removal      | 9         |
| Seal oil cooler            | 12        |
| NDE events                 | 10        |
| Excluded                   | 58        |

Table 4-1 HX OE cases captured

As seen in the table, 58 OE cases were excluded. This was because the root cause of the events was due to unusual events. For example, tube plug failures and foreign material intrusion are not caused by in-service HX material performace issues.

Next, the cases for each HX type will be detailed. The cases will begin with a summary followed by a discussion of the category parameters captured.

### 4.1 Condenser OE Cases Captured

Of the HX types, the condenser received the most attention in the survey with 38 captured OE events. Table 4-2 summarizes the OE findings.

| Table 4-2     |             |             |     |
|---------------|-------------|-------------|-----|
| Summary of OE | captures fe | or condense | ers |

| Material           | Damage                                      | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type            |
|--------------------|---|-----------------|-------------------------|----------------------|-------------------------------|
| Admiralty<br>brass | General ID wall loss/wear                   |                 |                         |                      | ECT bobbin coil not effective |
|                    | Underdeposit corrosion                      | 15 y            | N/C                     | N/C                  | ECT bobbin coil               |
|                    | OD steam corrosion                          |                 |                         |                      | ECT bobbin coil               |
| CuNi 90/10         | Underdeposit corrosion                      | N/C             | N/C                     | 70% TW               | ECT bobbin coil               |
|                    | OD steam<br>erosion                         | N/C             | N/C                     | 50% TW               | ECT bobbin coil (amplitude)   |
| 304 SS             | Underdeposit corrosion                      | 15 y            | N/C                     | N/C                  | ECT bobbin coil               |
|                    | OD steam<br>erosion /droplet<br>impingement | 20 y            | N/C                     | N/C                  | ECT bobbin coil not effective |
|                    | ID inlet erosion                            | 10 y            | N/C                     | N/C                  | ECT bobbin coil               |
| SeaCure            | OD steam<br>erosion /droplet<br>impingement | 10 y            | N/C                     | N/C                  | ECT magnetic saturation       |
| Titanium           | OD steam<br>erosion                         | N/C             |                         |                      | ECT bobbin coil               |
|                    | High-cycle<br>fatigue (at<br>scratches)     | 4 to 5 y        | N/C                     | N/C                  | ECT bobbin coil not effective |

N/C = Not Captured

As seen in the table, the condenser OE reported tubing leaks caused by both ID and OD corrosion damage mechanisms.

For ID damage, wear, underdeposit corrosion, and tube inlet erosion were reported. To address these ID damage mechanisms, some plants installed corrosion-resistance materials. In the material list shown in the table, admiralty brass is considered the most corrosion susceptible, followed by 90/10 copper-nickel (CuNi 90/10), 304 stainless steel (304 SS), seacure ferritic stainless steel (SeaCure), and titanium, in that order.

For OD damage, steam erosion and droplet impingement was reported. In these cases, the tubes located in the outer perimeter of the condenser were the most susceptible. To address this susceptibility, some plants installed SeaCure tubes in the outer perimeter of the bundle, while other plants upgraded to titanium tubes altogether.

Titanium was reported to exhibit premature cracking failure at some plants. This premature failure was reported to result from the combination of flow-induced vibration and cracking initiated at OD scratches. The flow-induced vibration may have been the result of non-optimal tube support span, while the scratches were believed to have been introduced during tubing installation.

Condenser leak detection was performed primarily by a combination of video cameras and helium leak tracing techniques.

Condenser tubing integrity examinations were performed primarily with bobbin-coil sensor eddy current (ET) methods. For some types of corrosion damage, the bobbin-coil ET sensor was reported to be not effective. These cases included:

- Tube wear
- OD droplet impingement
- Circumferential cracks at tube supports
- High-cycle fatigue cracks

Also, for OD steam erosion, the analysis techniques were modified and "signal amplitude response" methods were used instead of the standard signal phase response assessment. Finally, for SeaCure tubing, magnetic saturation ET techniques were used.

Tables 4-3 to 4-6 list the condenser survey results details. Because of the number of entries, the data for a particular event were separated into two tables. Accordingly, Tables 4-3 and 4-4 are Part 1 and Part 2 of the same cases. The same applies to Tables 4-5 and 4-6.

| Case | Date       | Material        | Diameter/Wall      | Event                             | Testing Method    |
|------|------------|-----------------|--------------------|-----------------------------------|-------------------|
| 1    | 8/8/2013   | 304 SS          | 1"/0.028"          | Tube leaks                        | N/C               |
| 2    | 11/2/2012  | N/C             | N/C                | Two tube leaks                    | Borescope         |
| 3    | 11/27/2012 | N/C             | N/C                | Tube leak                         | Borescope         |
| 4    | 7/6/2012   | 304 SS          | 1"/22 BWG – 0.028" | Tube cracks caused plugging       | ET                |
| 5    | 2/29/2012  | 304 SS          | 7/8"/0.028"        | Seam weld lack of<br>fusion       | ECT               |
| 6    | 2/22/2012  |                 | N/C                | Tube leak                         | Chemistry, helium |
| 7    | 2/21/2012  | Carbon<br>steel | N/C                | Hotwell and false bottom cracking | Visual            |
| 8    | 12/19/2011 | Titanium        | N/C                | Leak                              | Helium, visual    |
| 9    | 10/7/2011  | 304 SS          | N/C                | Leak                              | Helium            |
| 10   | 9/21/2011  | Titanium        | 0.875"/0.028"      | Tube leak                         | Borescope, ET     |

Table 4-3 OE captures for condensers – 2008 to March 2013, Part 1

### Table 4-3 (Continued) OE captures for condensers – 2008 to March 2013, Part 1

| Case | Date      | Material           | Diameter/Wall | Event                            | Testing Method   |
|------|-----------|--------------------|---------------|----------------------------------|--|
| 11   | 5/26/2011 | SeaCure            | N/C           | Tube leaks                       | Chemistry  |
| 12   | 5/23/2011 | Admiralty<br>brass | N/C           | Tube leaks                       | ET   |
| 13   | 1995      | Admiralty<br>brass | N/C           | Replacement                      | ET   |
| 14   | 1/11/2011 | Admiralty<br>brass | N/C           | Tube leak                        | Chemistry,<br>conductivity                                   |
| 15   | 5/26/2010 | Titanium           | N/C           | Tube leaks                       | Chemistry  |
| 16   | 12/7/2009 | 304 SS             | 1"/0.028"     | Tube leaks (11 leaks since 2004) | Chemistry – ECT<br>ineffective                               |
| 17   | 7/8/2009  | 304 SS             | 1"/0.028"     | Tube leaks and circ<br>cracks    | ECT bobbin, ECT<br>matrix, and<br>rotating pancake<br>(MRPC) |
| 18   | 3/20/2009 | SeaCure            | N/C           | Tube leak                        | Chemistry,<br>helium, ECT                                    |
| 19   | 2/25/2009 | Admiralty<br>brass | N/C           | Tube leak                        | Sodium   |
| 20   | 4/30/2008 | 304 SS             | 1"/0.028"     | Circ cracks 1″ from<br>tubesheet | Visual   |

1" = 25.4 mm

### Table 4-4 OE captures for condensers – 2008 to March 2013, Part 2

| Case | Date       | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|---|-----------------|-------------------------|----------------------|
| 1    | 8/8/2013   | Liquid droplet impingement near the tube-<br>to-support plates.                 | N/C             | N/C                     | N/C                  |
| 2    | 11/2/2012  | Linear splits caused by tube wear assisted by tube scoring during installation. | N/C             | N/C                     | N/C                  |
| 3    | 11/27/2012 | Linear splits caused by tube wear assisted by tube scoring during installation. | N/C             | N/C                     | N/C                  |
| 4    | 7/6/2012   | Fatigue linear cracks found by ET at the tube weld seam.                        | N/C             | N/C                     | N/C                  |

### Table 4-4 (Continued) OE captures for condensers – 2008 to March 2013, Part 2

| Case | Date       | Morphology  | Service<br>Life                   | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|---|-----------------------------------|-------------------------|----------------------|
| 5    | 2/29/2012  | Seam weld lack-of-fusion fabrication defects – ECT significantly oversized the defects.   | N/C                               | N/C                     | N/C                  |
| 6    | 2/22/2012  | Unknown.  | N/C                               | N/C                     | N/C                  |
| 7    | 2/21/2012  | Cyclic fatigue.   | N/C                               | N/C                     | N/C                  |
| 8    | 12/19/2011 | High energy flow impingement probably caused by heater drain tank sparger failure.  | N/C                               | N/C                     | N/C                  |
| 9    | 10/7/2011  | Small pit at tube-to-tubesheet joint too difficult to detect by helium – coating applied.   | N/C                               | N/C                     | N/C                  |
| 10   | 9/21/2011  | High-cycle axial fatigue initiated at OD<br>scratches – crack growth: Three cycles –<br>TSP separation further apart than<br>common.                    | N/C                               | N/C                     | N/C                  |
| 11   | 5/26/2011  | Pitting caused by steam erosion<br>impingement, RFET not effective, Mag-<br>sat ET demonstrated on failed tube.   | N/C                               | N/C                     | N/C                  |
| 12   | 5/23/2011  | Pitting near outlet of tube, tube general wall thinning, OD corrosion, linear extrusion.  | 5639<br>days                      | N/C                     | N/C                  |
| 13   | 1995       | Pitting, erosion/general wall thinning.   | 5940<br>days                      | N/C                     | N/C                  |
| 14   | 1/11/2011  | Internal wear, tube leak due to wear in combination with fabrication linear extruded defects, ECT ineffective at detecting wear.                        | N/C                               | N/C                     | N/C                  |
| 15   | 5/26/2010  | Groove indentations caused by scale<br>cleaning cutter blades followed by fatigue<br>cracks – ECT ineffective – working with<br>EPRI.                   | Four<br>years<br>from<br>cleaning | N/C                     | N/C                  |
| 16   | 12/7/2009  | Liquid droplet impingement erosion – ECT<br>bobbin coil ineffective at detecting leaks –<br>Pit size OD 0.027" wide, ID 0.006" wide<br>+15% OD erosion. | 20 years                          | N/C                     | N/C                  |

### Table 4-4 (Continued) OE captures for condensers – 2008 to March 2013, Part 2

| Case | Date      | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|---|-----------------|-------------------------|----------------------|
| 17   | 7/8/2009  | Pin hole leaks adjacent to TSP caused by<br>droplet impingement, circumferential<br>cracks at TSP 75% TW, ETC undersized<br>pits and significantly oversized wear –<br>Circ cracks found by matrix probe. Circ<br>cracks previously reported caused by<br>flow-induced vibration. | N/C             | N/C                     | N/C                  |
| 18   | 3/20/2009 | OD steam erosion.   | 10 years        | N/C                     | N/C                  |
| 19   | 2/25/2009 | Unknown.  | N/C             | N/C                     | N/C                  |
| 20   | 4/30/2008 | Tube high-cycle fatigue circ. cracks caused by flow-induced vibration.  | N/C             | N/C                     | N/C                  |

1″ = 25.4 mm

### Table 4-5 OE captures for condensers – 2002–2007, Part 1

| Case | Date       | Material           | Diameter/Wall | Event   | Testing Method               |
|------|------------|--------------------|---------------|---|------------------------------|
| 21   | 10/2/2007  | Admiralty<br>brass | N/C           | Tube leak                                       | Conductivity                 |
| 22   | 12/5/2006  | CuNi 70/30         | N/C           | Tube leak                                       | Chemistry                    |
| 23   | 5/25/2006  | Admiralty<br>brass | 1"/0.049"     | Tube leaks                                      | Chemistry                    |
| 24   | 3/12/2006  | CuNi 70/30         | N/C           | Tube leak                                       | Conductivity -<br>ECT        |
| 25   | 3/7/2006   | 304 SS             | 7/8"/0.028"   | Tube leaks – ID<br>pitting                      | ECT                          |
| 26   | 1/17/2006  | 304 SS             | N/C           | Tube leaks                                      | Chemistry +<br>helium plenum |
| 27   | 12/20/2005 | Titanium           | N/C           | Tube leak                                       | Sodium, ECT                  |
| 28   | 12/3/2005  | 304 SS             | 7/8"/0.028"   | Tube sheared                                    | Chemistry                    |
| 29   | 2005       | 304 SS             | 1"/0.028"     | Tube leaks                                      | N/C                          |
| 30   | 12/25/2004 | SS                 | N/C           | Turbine oil waste<br>(slop) drain pipe<br>crack | Loss of vacuum               |
| 31   | 6/4/2004   | N/C                | N/C           | Tube leaks                                      | Chemistry                    |

### Table 4-5 (Continued) OE captures for condensers – 2002–2007, Part 1

| Case | Date       | Material           | Diameter/Wall | Event  | Testing Method                  |
|------|------------|--------------------|---------------|--|---------------------------------|
| 32   | 12/21/2003 | CuNi 70/30         | N/C           | Tube leak  | Chemistry, tracer,<br>ECT       |
| 33   | 11/7/2003  | 304 SS             | 7/8"/0.028"   | Tube leaks – ID<br>pitting + OD steam<br>erosion | N/C                             |
| 34   | 5/3/2003   | Admiralty<br>brass | 1"/0.049"     | Tube cracks                                      | ECT                             |
| 35   | 4/2/2003   | N/C                | N/C           | 3/8″ tube support<br>plate crack                 | Visual                          |
| 36   | 1/14/2003  | Titanium           | N/C           | Tube leak  | Chemistry - SG                  |
| 37   | 5/11/2002  |                    | N/C           | Tube leak  | Chemistry, leak<br>test and ECT |
| 38   | 2/26/2002  | 304 SS             | 7/8"/0.028"   | Tube leaks – ID<br>pitting                       | ECT                             |

#### Table 4-6 OE captures for condensers – 2002–2007, Part 2

| Case | Date       | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria  |
|------|------------|--|-----------------|-------------------------|---|
| 21   | 10/2/2007  | Pitting – MIC – Decaying organic<br>matter > sulfides > MIC.   | N/C             | N/C                     | N/C   |
| 22   | 12/5/2006  | Foreign object believed caused tube leak. ET at previous outage did not detect wear.                         | N/C             | N/C                     | N/C   |
| 23   | 5/25/2006  | OD droplet impingement – ECT could not detect the leak locations.  | N/C             | N/C                     | N/C   |
| 24   | 3/12/2006  | OD steam impingement erosion in inner 3 <sup>rd</sup> tube row – outer two tube rows made out of SeaCure.    | N/C             | N/C                     | 50% TW for<br>SeaCure<br>outer rows,<br>70% for inner<br>rows |
| 25   | 3/7/2006   | Manganese-chloride pitting underdeposit corrosion.   | N/C             | N/C                     | N/C   |
| 26   | 1/17/2006  | Tubes in perimeter – possible causes steam impingement erosion.  | N/C             | N/C                     | N/C   |
| 27   | 12/20/2005 | Fretting of tube caused by steam impingement in the vicinity of dump valve where deflector plate had fallen. | N/C             | N/C                     | N/C   |

### Table 4-6 (Continued) OE captures for condensers – 2002–2007, Part 2

| Case | Date       | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria     |
|------|------------|---|-----------------|-------------------------|--------------------------|
| 28   | 12/3/2005  | Cyclic bending fatigue caused by inadequate staking (support) and high steam flow rate.                                       | N/C             | N/C                     | N/C                      |
| 29   | 2005       | Leaks caused droplet impingement and steam erosion.   | N/C             | N/C                     | N/C                      |
| 30   | 12/25/2004 | High-cycle fatigue – cracks at bi-<br>metallic weld.  | N/C             | N/C                     | N/C                      |
| 31   | 6/4/2004   | Fatigue, internal tubes – no foreign objects.   | N/C             | N/C                     | N/C                      |
| 32   | 12/21/2003 | OD steam impingement erosion in<br>periphery tubing – tube plug criterion<br>changed from 70% to 60% for OD<br>steam erosion. | N/C             | N/C                     | 60% TW for<br>outer rows |
| 33   | 11/72003   | MIC and manganese-choride pitting<br>under silt deposits – OD grooving due<br>to steam erosion.                               | N/C             | N/C                     | N/C                      |
| 34   | 5/3/2003   | OD stress corrosion cracking caused by pre-service storage contamination.   | N/C             | N/C                     | N/C                      |
| 35   | 4/2/2003   | Flow-induced vibration high-cycle fatigue.  | N/C             | N/C                     | N/C                      |
| 36   | 1/14/2003  | Cracks initiated at scratches.  | N/C             | N/C                     | N/C                      |
| 37   | 5/11/2002  | Underdeposit pitting – SeaCure material use in Unit 1.  | N/C             | N/C                     | N/C                      |
| 38   | 2/26/2002  | MIC and manganese-choride pitting under silt deposits.  | N/C             | N/C                     | N/C                      |

### 4.2 Feedwater Heater OE Cases Captured

As listed in Table 4-1, 25 feedwater heater OE cases were captured. Table 4-7 summarizes the OE findings.

| Material     | Damage  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type     |
|--------------|---|-----------------|-------------------------|----------------------|------------------------|
| 304 SS       | Tube wear at supports   | 29 y            | 6 y                     | 50% TW               | ECT bobbin coil        |
|              | Tube wear at supports +<br>high-cycle fatigue (high-<br>velocity operation) | 3 у             | N/C                     | N/C                  | ECT bobbin coil        |
|              | Tube wear – steam<br>impingement near drain<br>cooler                       | 30 y            | N/C                     | N/C                  | ECT bobbin coil        |
| Carbon steel | Internals corrosion   | 24 y            | N/C                     | N/C                  | Visual                 |
|              | Steam impingement plate failure   | 14–28 y         | N/C                     | N/C                  | Visual                 |
|              | Vessel shell erosion  | 25 y            | N/C                     | N/C                  | Pulsed eddy<br>current |

### Table 4-7Summary of OE captures for feedwater heaters

### N/C = Not Captured

As seen in Table 4-7, the feedwater heater OE cases included leaks caused by OD corrosion, damage to the internals, the vessel shell, and the steam impingement plate. The tubing material for the cases was 304 SS, but the internals and vessel shell were made out of carbon steel.

For tubing, the damage mechanisms included wear or high-cycle fatigue. Tube wear was reported at the tubing supports or caused steam impingement near the drain cooler. Tubing high-cycle fatigue was caused by flow-induced vibration associated with high shell-side steam velocity. In the latter case, the OE indicated that HX manufacturers provide a "critical shell-side steam velocity" not to be exceeded because of flow-induced vibration concerns. However, plants that undergo power uprates sometimes find themselves in need of operating above the critical steam velocity recommendations. In addition, tube support enlargement and low-level drain cooler flashing are cited as enhancing tube vibration damage.

Premature tube failure was reported to be caused by the combination of tube wear at supports and high-cycle fatigue. In the cited event, the high-cycle fatigue may have been the result of operating at a high shell-side steam velocity.

Internals corrosion was reported to occur for various reasons including failure to remove noncondensable gases and improper steam flow motion. Inadequate non-condensable gas extraction was reported to be caused by vent channel or vent pipe failures. Improper steam flow was cited as the result of steam impingement plate dislodgement, tube support, or drain cooler shroud damage. This improper steam flow motion was suspected to cause tube failures and/or heater shell erosion.

#### Heat Exchanger OE Surveys

Tubing integrity assessment was performed primarily with ET bobbin coil techniques. In addition to looking for tube wear at the supports, the techniques were sometimes modified to assess tube support enlargement.

The internals damage assessment was done primarily with video cameras.

Finally, the heater shell wear inspection was typically performed with a combination of pulsed ET and ultrasonic techniques. The pulsed ET was used for screening the shell wall thickness with the insulation in place. In the areas that were identified as suspect, the insulation was removed, and the remaining wall thickness was measured with ultrasonics.

Tables 4-8 to 4-11 list the details of the feedwater heater OE investigation results. As was done in Section 4.1, the data for a particular event were divided into two tables.

| Case | Date       | Material | Diameter/Wall           | Event   | Testing Method                                 |
|------|------------|----------|-------------------------|---|--|
| 39   | 4/18/2013  | 304 SS   | N/C                     | Level controller set too low –<br>tube leak suspected                     | Water level                                    |
| 40   | 4/9/2012   | N/C      | N/C                     | Tube leaks (five tubes)   | Flow rate                                      |
| 41   | 12/29/2010 | 304 SS   | 3/4"/20 AW              | Tube leak and alternate drain valve failed                                | Heater level                                   |
| 42   | 4/23/2010  | N/C      | N/C                     | Tube leaks (12 tubes)   | N/C  |
| 43   | 4/22/2010  | N/C      | N/C                     | Tube leaks  | Mismatch<br>feedwater flow,<br>water leak test |
| 44   | 4/14/2009  | N/C      | N/C                     | Tube ruptures (four tubes)<br>and leaks (two)                             | Increased<br>condensate flow,<br>ECT           |
| 45   | 9/19/2009  | N/C      | N/C                     | Tube leaks  | Video, ECT                                     |
| 46   | 4/23/2009  | N/C      | N/C                     | Tube ruptures, drain cooler<br>shrouds and internals<br>severely corroded | Visual, leak test,<br>ECT                      |
| 47   | 1/12/2009  | 304 SS   | N/C                     | Tube ruptures (eight tubes) in top of drain cooler section                | Pressure                                       |
| 48   | 4/11/2008  | N/C      | N/C                     | Tube ruptures (12 tubes)  | Chemistry                                      |
| 49   | 3/7/2008   | 304 SS   | 3/4"/18 BWG<br>- 0.049″ | Tube rupture (two tubes)  | Pressure, water<br>levels, ECT<br>bobbin       |
| 50   | 1/21/2008  | N/C      | N/C                     | Tube rupture  | Water level, ECT                               |

Table 4-8OE captures for feedwater heaters – 2008 to March 2013, Part 1

| Table 4-9  |
|--|
| OE captures for feedwater heaters – 2008 to March 2013, Part 2 |

| Case | Date       | Morphology  | Service<br>Life              | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|---|------------------------------|-------------------------|----------------------|
| 39   | 4/18/2013  | Unknown.  | N/C                          | N/C                     | N/C                  |
| 40   | 4/9/2012   | Unknown.  | N/C                          | N/C                     | N/C                  |
| 41   | 12/29/2010 | Unknown.  | To be<br>replaced<br>in 2015 | N/C                     | N/C                  |
| 42   | 4/23/2010  | Tube extensively damaged exhibiting<br>leaks (12 tubes) found. Root cause not<br>established, although it is suspected<br>that the damage was caused by<br>vibration, steam flashing, or ID pitting.<br>Leaking tube left unrepaired in<br>previous outage – 100% inspection<br>planned for next outage.  | N/C                          | N/C                     | N/C                  |
| 43   | 4/22/2010  | Tube leaks caused by wear at supports adjacent to the drain nozzle. ET failed to detect wear.   | N/C                          | N/C                     | N/C                  |
| 44   | 4/14/2009  | Flow-induced vibration – two phase<br>flow because of tube support<br>enlargement or low level in drain cooler<br>flashing is also a possibility.   | N/C                          | N/C                     | N/C                  |
| 45   | 9/19/2009  | Tube leaks found in the vicinity of a<br>failed non-condensable gases vent.<br>Video inspection of the severed vent<br>channel suggested fatigue failure.<br>Sampling of tubes pulled suggested<br>that the tube leaks may have been<br>caused by vibration-induced fretting.   | N/C                          | N/C                     | N/C                  |
| 46   | 4/23/2009  | Tube ruptures caused by vibration and<br>steam impingement from holes in the<br>drain cooler shroud. The shroud<br>damage was likely caused by steam<br>impingement from the extraction steam<br>inlet pipe located above the damaged<br>areas. Long tube support spacing<br>contributed to tube vibration. Shell ID<br>erosion wall loss was also found. | N/C                          | N/C                     | N/C                  |

#### Heat Exchanger OE Surveys

### Table 4-9 (Continued) OE captures for feedwater heaters – 2008 to March 2013, Part 2

| Case | Date      | Morphology  | Service<br>Life      | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|---|----------------------|-------------------------|----------------------|
| 47   | 1/12/2009 | Tube vibration cracking at supports –<br>Inadequate venting caused corrosion<br>of internals (drain cooler shroud and<br>tube supports) allowing steam to enter<br>drain cooler section and caused tube<br>vibrations. ECT procedure used did not<br>detect precursor tube work hardening<br>cracking damage. ECT "Absolute Drift"<br>technique previously developed was<br>not used. | 28 years<br>299 days | N/C                     | N/C                  |
| 48   | 4/11/2008 | Baffle plate had a broken weld near failed tubes.   | N/C                  | N/C                     | N/C                  |
| 49   | 3/7/2008  | Tubes rupture – flow-induced vibration<br>– severed behind the tubesheet.   | N/C                  | N/C                     | N/C                  |
| 50   | 1/21/2008 | Unknown.  | N/C                  | N/C                     | N/C                  |

#### Table 4-10 OE captures for feedwater heaters – 2002–2007, Part 1

| Case | Date       | Material     | Diameter/Wall        | Event  | Testing Method           |
|------|------------|--------------|----------------------|--|--------------------------|
| 51   | 2/11/2007  | Carbon steel | N/C                  | Shell and<br>heater internals<br>erosion             | Shell OD NDT,<br>visual  |
| 52   | 10/23/2007 | 304 SS       | 3/4"/20 BWG – 0.035" | Tube leak  | ECT                      |
| 53   | 5/21/2007  | N/C          | N/C                  | Impingement<br>plate failure<br>caused tube<br>leaks | Visual                   |
| 54   | 10/30/2006 | N/C          | N/C                  | Baffle plate in<br>drain cooler<br>degraded          | ECT                      |
| 55   | 8/28/2006  | N/C          | N/C                  | Tube leaks   | Pressure in booster pump |
| 56   | 1/25/2006  | N/C          | N/C                  | Tube leaks   | N/C                      |
| 57   | 12/6/2005  | 304 SS       | 3/4"/20 BWG – 0.035" | Tube leaks   | Water level              |
| 58   | 10/20/2005 | 304 SS       | 5/8"/                | ET indication<br>sent for lab<br>evaluation          | ET                       |

### Table 4-10 (Continued) OE captures for feedwater heaters – 2002–2007, Part 1

| Case | Date       | Material     | Diameter/Wall | Event   | Testing Method              |
|------|------------|--------------|---------------|---|-----------------------------|
| 59   | 2/12/2005  | N/C          | N/C           | Tube rupture  | Borescope                   |
| 60   | 9/24/2004  | 304 SS       | N/C           | Tube leak   | Drain flow<br>increase, ECT |
| 61   | 3/1/2004   | Vents 304 SS | N/C           | C-vent nozzle<br>cracking due to<br>IGSCC                             | Dye penetrant<br>+ UT       |
| 62   | 10/26/2003 | N/C          | N/C           | Impingement<br>plate and baffle<br>plate cracks<br>and weld<br>damage | Visual -<br>borescope       |
| 63   | 4/22/2002  | N/C          | N/C           | Tube failures due to vibration  | N/C                         |

1" = 25.4 mm

### Table 4-11 OE captures for feedwater heaters – 2002–2007, Part 2

| Case | Date       | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|--|-----------------|-------------------------|----------------------|
| 51   | 2/11/2007  | OD heater found to exhibit wall loss<br>following inspection. After removing a<br>portion of the shell for repairs, extensive<br>erosion of the internals were found: the<br>lower support beam had holes, the spacer<br>tubes were eroded, and an 18" section of<br>the vent pipe fallen off. Periodic NDE of<br>the shell performed and suggests shell<br>and internals erosion correlate. | 25 years        | N/C                     | N/C                  |
| 52   | 10/23/2007 | TGSCC initiated at scoring marks and<br>include chloride traces suggesting<br>exposure during fabrication or unusual<br>event.   | N/C             | N/C                     | N/C                  |
| 53   | 5/21/2007  | Impingement plate design defective –<br>plate broke off causing rubbing on tubes<br>causing the leaks, cable attached to plate<br>ended up in isolation valve (FME).   | N/C             | N/C                     | N/C                  |

### Table 4-11 (Continued) OE captures for feedwater heaters – 2002–2007, Part 2

| Case | Date       | Morphology  | Service<br>Life      | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|---|----------------------|-------------------------|----------------------|
| 54   | 10/30/2006 | No. 5 heaters had increased baffle<br>damage detected and tracked with ECT.<br>Damage appears to have occurred after<br>power uprate. No tube vibration damage<br>indication was found and no tubes were<br>plugged. Appears baffle spacing close<br>enough to limit vibration. | N/C                  | N/C                     | N/C                  |
| 55   | 8/28/2006  | Vibration-induced wear at tube support<br>plate, caused by localized high-velocity<br>steam flow. Tubes with 48% to 55% in<br>2000. Inspection frequency revised to 6<br>years, 60% wall loss plug criteria revised<br>up.  | Wear rate<br>52%/6 y | N/C                     | N/C                  |
| 56   | 1/25/2006  | Vibration damage caused by design weakness or tube degradation.   | N/C                  | N/C                     | N/C                  |
| 57   | 12/6/2005  | High-cycle fatigue caused by flow-induced vibration due to tube/support wear – shell-side velocity run at 114% of critical during a three-year period, should be < 75%.   | N/C                  | N/C                     | N/C                  |
| 58   | 10/20/2005 | TGSCC 90% deep found in pulled tube,<br>ET depth within 15% - in another pulled<br>tube ET calls were false.  | N/C                  | N/C                     | N/C                  |
| 59   | 2/12/2005  | Not established.  | N/C                  | N/C                     | N/C                  |
| 60   | 9/24/2004  | Tube fretting caused by impingement plate becoming dislodged.   | N/C                  | N/C                     | N/C                  |
| 61   | 3/1/2004   | IGSCC.  | N/C                  | N/C                     | N/C                  |
| 62   | 10/26/2003 | Flow-induced vibration on the impingement plate – impingement plate weld found to be of poor quality.   | 28 years             | N/C                     | N/C                  |
| 63   | 4/22/2002  | Vibration – excessive shell-side velocity caused by power upgrade.  | N/C                  | N/C                     | N/C                  |

### 4.3 Emergency Diesel Generator HX OE Cases Captured

The emergency diesel generator system includes three HXs also called *coolers*: the lubrication (lube) oil, the jacket water, and the intercooler HXs. The survey captured 12 OE cases for these HXs, which are summarized in Table 4-12.

| Material              | Damage                      | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type             |
|-----------------------|-----------------------------|-----------------|-------------------------|----------------------|--------------------------------|
| Lube and Jacket Water |                             |                 |                         |                      |                                |
| Admiralty brass       | Tube underdeposit corrosion | 31 y            | 2 y                     | 59% TW               | ECT bobbin coil                |
|                       | Tube inlet erosion          | 12y–16 y        | N/C                     | 55% TW               | ECT bobbin coil<br>(amplitude) |
| Intercooler           |                             |                 |                         |                      |                                |
| Admiralty brass       | Tube inlet corrosion        | 11y–16 y        | N/C                     | 55% TW               | ECT bobbin coil<br>(amplitude) |
| CuNi 90/10            | Tube inlet erosion          | 21 y            | N/C                     | N/C                  | ECT bobbin coil (amplitude)    |

Table 4-12 Summary of OE captures for emergency diesel generator HXs

N/C = Not Captured

As seen in the table, the tubing material used in these heaters included admiralty brass and CuNi 90/10.

Some of the HXs were reported to be operated intermittently, with periods of stagnant flow. Accordingly, tubing in these HXs was found to be susceptible to underdeposit corrosion. A twoyear cleaning and inspection frequency was reported that was used for underdeposit corrosion management during a 31-year service life.

### Heat Exchanger OE Surveys

Table 4-13

When the HXs were in operation, the OE reported cases of high-flow velocities that caused tube inlet erosion damage, effectively reducing their service life. The "high-flow velocity" threshold depended on the tubing material used. For admiralty brass and CuNi 90/10, the thresholds cited were 6 ft/sec and 8 ft/sec (1.8 and 2.4 m/sec), respectively, indicating that the latter material was more resistant to inlet erosion corrosion.

In addition, tubing in floating head HXs were reported to be susceptible to circumferential cracking at the tubesheet.

Examination for tubing integrity was performed primarily with ET bobbin coil methods. When inlet erosion was the primary concern, the amplitude drift calibration technique was used for sizing the damage.

Tables 4-13 to 4-16 list the details of the emergency diesel generator HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

| Case | Date       | Material              | Diameter/Wall | Event                  | Testing Method                      |
|------|------------|-----------------------|---------------|------------------------|-------------------------------------|
| 64   | 7/4/2012   | Admiralty brass       | N/C           | Tube leak              | Crankcase pressure raise            |
| 65   | 10/1/2009  | Carbon steel<br>SA53B | N/C           | Head pinhole<br>leak   | Visual                              |
| 66   | 2/26/2009  | Admiralty brass       | N/C           | Tube leaks             | Contaminated water, mechanical, ECT |
| 67   | 1/25/2009  | Admiralty brass       | N/C           | Tube leak              | Pressure increase, pressure test    |
| 68   | 11/19/2008 | N/C                   | N/C           | Channel wall corrosion | Visual, UT                          |
| 69   | 7/21/2008  | N/C                   | N/C           | Tube leak              | Oil contamination, ECT, leak test   |

OE captures for emergency diesel generator HX – 2008 to March 2013, Part 1

### Table 4-14 OE captures for emergency diesel generator HX – 2008 to March 2013, Part 2

| Case | Date       | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|---|-----------------|-------------------------|----------------------|
| 64   | 7/4/2012   | N/A – tube failure in the lubrication oil HX suspected, pressure test not effective at locating the leak.   | N/C             | N/C                     | N/C                  |
| 65   | 10/1/2009  | MIC localized corrosion, inhibitor injection deficient, no UT monitoring previously performed.  | N/C             | N/C                     | N/C                  |
| 66   | 2/26/2009  | Jacket water HX tube leaks caused by inlet<br>erosion due to high-flow velocity (>12 ft/s) –<br>mechanical measurements to determine<br>remaining tube wall found not to be<br>accurate.  | N/C             | N/C                     | N/C                  |
| 67   | 1/25/2009  | Leaking tube had circumferential cracks<br>near the floating-end tubesheet – reason<br>unknown.   | N/C             | N/C                     | N/C                  |
| 68   | 11/19/2008 | Channels never cleaned or inspected,<br>tubercles formed, wall loss 65% under<br>tubercles.   | N/C             | N/C                     | N/C                  |
| 69   | 7/21/2008  | Lube oil HX tube leaks caused by erosion<br>corrosion at tube-tubesheet area past the<br>plastacor coating caused by excessive flow<br>rate. ECT ineffective. ECT procedure<br>modified to use signal amplitude for erosion<br>detection. | 12 years        | N/C                     | N/C                  |

1 ft/s = 0.31 m/s

| Table 4-15  |      |
|---|------|
| OE captures for emergency diesel generator HX – 2001–2007, Pa | rt 1 |

| Case | Date      | Material        | Diameter/Wall       | Event  | Testing Method         |
|------|-----------|-----------------|---------------------|--|------------------------|
| 70   | 6/20/2007 | CuNi 90/10      | 3/4" OD –<br>18 BWG | Tube leaks   | N/C                    |
| 71   | 2/12/2007 | N/C             | N/C                 | Tube leaks   | ECT                    |
| 72   | 4/23/2006 | Admiralty brass | N/C                 | Tube leaks   | Leak test, ECT, visual |
| 73   | 2/7/2006  | Admiralty brass | 5/8"/0.049"<br>wall | Pitting (seven<br>tubes plugged<br>in jacket<br>cooling water<br>HX and nine<br>tubes plugged<br>in lube oil<br>cooler HX) | ECT                    |
| 74   | 1/4/2002  | Admiralty brass | 3/4"/0.049"<br>wall | Erosion<br>corrosion<br>(severe)   | ETC – absolute drift   |
| 75   | 5/22/2001 | N/C             | N/C                 | Tube cracking  | Visual                 |

1" = 25.4 mm

### Table 4-16

### OE captures for emergency diesel generator HX – 2001–2007, Part 2

| Case | Date      | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|---|-----------------|-------------------------|----------------------|
| 70   | 6/20/2007 | Intercooler tube leaks caused by erosion corrosion in 1 <sup>st</sup> 1.5" past the coating which was applied up to 1.3" – Flow velocity 9 ft/sec >8 ft/sec threshold.  | 21 years        | N/C                     | N/C                  |
| 71   | 2/12/2007 | Intercooler tube inlet erosion corrosion in 1 <sup>st</sup><br>6" due to high-flow rate (1850 gpm) – No<br>coating applied – ECT within 1" from<br>tubesheet not effective but further<br>downstream. Also visual not effective at<br>damage detection.           | 11 years        | N/C                     | N/C                  |
| 72   | 4/23/2006 | Jacket water HX tube leaks after two years<br>of service due to SCC at tube-to-tubesheet<br>interface – probably caused by floating head<br>HX design – previous HX had tube life of<br>8–12 years – plan to use specialized ECT<br>(X-probe) at next inspection. | 2 years         | N/C                     | N/C                  |

### Table 4-16 (Continued) OE captures for emergency diesel generator HX – 2001–2007, Part 2

| Case | Date      | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|--|-----------------|-------------------------|----------------------|
| 73   | 2/7/2006  | Pitting wall loss > 59% per ECT inspection<br>in jacket cooling and lube oil HXs – Low-<br>flow operation – Possible mechanisms:<br>underdeposit corrosion and dezincification,<br>HX operated monthly, flow stagnant for the<br>remainder 30 days. DAEC did not eddy<br>current test the EDG HXs in the past.   | 31 years        | 2 years                 | 59%                  |
| 74   | 1/4/2002  | Severe corrosion was found with ECT in the intercooler HX and also present in the jacket water and lube oil HXs. Corrosion mechanism for the intercooler was suspected to be erosion/corrosion. The intercooler was operated at flows of 5–10 fps; the recommended value is 6 fps. Dealloying may also have been present. Dezincification conditions are favored during periods of stagnant operation. | 16 years        | N/C                     | 55%                  |
| 75   | 5/22/2001 | Finned tube cracks at the soldered joints<br>caused by swelling and vibration –<br>Corrosion of supports due to salt-laden<br>atmosphere and thermal cycling were the<br>drivers.  | N/C             | N/C                     | N/C                  |

1″ = 25.4 mm

1 gpm = 3.8 lpm 1 ft/s = 0.31 m/s

### 4.4 Closed Cooling Water HX OE Cases Captured

As mentioned in Section 3.2, the closed cooling water system includes the HXs used to remove heat from systems that carry radioactive fluids. The survey captured 12 OE cases for these HXs, which are summarized in Table 4-12.

| Material   | Damage   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type                |
|------------|--|-----------------|-------------------------|----------------------|-----------------------------------|
| Admiralty  | Tube underdeposit corrosion                                | 35 y            | 3 у                     | 60% TW               | ECT bobbin coil                   |
| brass      | Tube aggressive<br>underdeposit corrosion                  | 1.5–5 y         | 1.5–3 y                 | N/C                  | ECT bobbin coil (Undersized pits) |
|            | Tube OD wear at supports                                   | 35 y            | 3 у                     | 45% TW               | ECT bobbin coil                   |
|            | Tube circumferential cracking at supports                  | 15 y            | 1.5 y                   | N/C                  | ECT bobbin coil (Not effective)   |
| CuNi 90/10 | Tube underdeposit corrosion                                | 23 у            | 4 y                     | 50% TW               | ECT bobbin coil                   |
|            | Tube aggressive<br>underdeposit corrosion                  | 1 y             | N/C                     | N/C                  | N/C                               |
|            | Tube fatigue circumferential<br>cracking at corroded areas | N/C             | N/C                     | N/C                  | ECT bobbin coil (Not effective)   |
| 304 SS     | Tube underdeposit corrosion                                | 14 y            | 0.5 y                   | N/C                  | ECT bobbin coil                   |
| AL6XN      | No damage reported   | N/C             | N/C                     | N/C                  | N/C                               |

### Table 4-17Summary of OE captures for closed cooling water HXs

N/C = Not Captured

As listed in the table, the tubing material used in these HXs included admiralty brass, CuNi 90/10, 304 SS, and AL6XN.

Some of HXs were reported to be susceptible to underdeposit corrosion. OE reported that long tubing service life was achieved with periodic cleaning and inspection. However, in some cases, premature tube failure was experienced when the HXs were operated intermittently and a "wet layup" procedure was used. In these cases, the combination of underdeposit corrosion and dealloying mechanisms resulted in an aggressive corrosion environment that reduced the service life.

Cases of high shell-side flow velocities were also reported, which caused tube OD wear damage at the supports. In some of these cases, circumferential cracking at the supports was also reported, which may have been caused by a combination of high-flow velocity and long tubing support spans.

Examination of tubing integrity was performed primarily with ET bobbin coil methods. In the ET examinations, the plugging criterion used was higher for ID-initiated corrosion (underdeposit corrosion) than for OD-initiated damage (tube wear). When assessing aggressive ID corrosion cases, ET was reported to undersize the pitting damage because a custom calibration standard was not used. Finally, ET was found to be not effective at the detection of circumferential cracking near supports.

Tables 4-18 to 4-21 list the details of the closed cooling water HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

| Case | Date       | Heat Exchanger   | Material           | Diameter/Wall          | Event  | Testing<br>Method              |
|------|------------|--|--------------------|------------------------|--|--------------------------------|
| 76   | 6/12/2014  | Closed cooling<br>water HX (all four<br>HXs)           | Copper             | 3/4"/0.049"            | Tube end ID<br>erosion and ID<br>pitting             | ECT                            |
| 77   | 7/12/2012  | Closed cooling<br>water HX                             | CuNi 90/10         | 3/4"/18 BWG-<br>0.049" | Tube leak –<br>extensive<br>damage found<br>with ECT | Tank level,<br>ETC             |
| 78   | 5/24/2012  | Turbine building<br>closed cooling<br>water HX 2A      | Admiralty<br>brass | 3/4"/0.049"            | Tube end<br>erosion                                  | ECT                            |
| 79   | 5/7/2012   | Reactor building<br>closed cooling<br>water HX 3A      | Admiralty<br>brass | 3/4"/0.049"            | Tube leaks   | Air test,<br>ECT               |
| 80   | 9/9/2011   | Component cooling water HX                             | 304 SS             | N/C                    | Multiple leaks                                       | Tank level,<br>ECT             |
| 81   | 12/31/2009 | Let down cooler –<br>component cooling<br>water system | N/C                | N/C                    | Tube leaks   | Radio<br>nuclides<br>detection |
| 82   | 10/23/2009 | Excess letdown<br>residual heat<br>removal HX          | N/C                | N/C                    | Tube leak  | N/C                            |
| 83   | 4/21/2008  | Component cooling<br>water HX room<br>cooler           | CuNi               | N/C                    | Tube leaks   | ECT                            |

Table 4-18OE captures for closed cooling water HX – 2008 to March 2013, Part 1

1" = 25.4 mm

### Table 4-19 OE captures for closed cooling HX – 2008 to March 2013, Part 2

| Case | Date       | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria                                      |
|------|------------|--|-----------------|-------------------------|---|
| 76   | 6/12/2014  | Tube-end ID erosion and widespread ID<br>pitting found by ECT with pit depths greater<br>than 30% TW. Sediment accumulations<br>(sand, silt, algae) regularly found on<br>tubesheets.  | 40<br>years     | N/C                     | N/C   |
| 77   | 7/12/2012  | Damage: (BWR) turbine building closed<br>cooling water HX had tube leak failure. The<br>HX is original equipment with 35 years of<br>service. Upon ECT examination, extensive ID<br>pitting and some OD wall loss at tube<br>supports were found with 23% of tubing<br>having wall loss estimates > 70%. Laboratory<br>analysis of sampled tubing confirmed general<br>ID corrosion and tube support wear. ECT may<br>have overestimated ID wall loss – ECT<br>standards revised to address overcalls. | 35<br>years     | 1 year                  | 60% TW<br>for ID<br>pitting /<br>45% TW<br>for OD<br>wear |
| 78   | 5/24/2012  | Tube end erosion found with ECT. ECT comparison with laboratory measurements was accurate.   | N/C             | N/C                     | N/C   |
| 79   | 5/7/2012   | ID inlet erosion and ID pitting. Chemical inhibitors added 10 years ago. ETC oversized erosion wall loss.  | 40<br>years     | N/C                     | N/C   |
| 80   | 9/9/2011   | Underdeposit/MIC pitting caused by<br>underdeposit and/or MIC due to material<br>susceptibility and low-flow velocity – cleaning<br>and inspection changed from 52 to 26 weeks.  | 14<br>years     | 0.5 year                | N/C   |
| 81   | 12/31/2009 | Letdown helical design HX manufactured by<br>Graham Co. – probable leak cause: fatigue<br>cracking – flow-induced vibration – no root<br>cause or NDE done.  | 16<br>years     | 6 years                 | N/C   |
| 82   | 10/23/2009 | Excess letdown residual heat removal HX<br>tube leak caused by fretting at the baffle plate<br>due to emergency operation at high shell-side<br>(RCS) flow rate above the HX design value.   | N/C             | N/C                     | N/C   |
| 83   | 4/21/2008  | Carrier Aerofin U and H cooler with CuNi<br>tubes exhibited leaks caused by underdeposit<br>corrosion/MIC pitting. Coolers were on a four-<br>year preventive maintenance schedule and in<br>2002, a change in the eddy through-wall<br>acceptance criteria was made. However,<br>leaks developed ahead of maintenance sche-<br>dule so it is planned to replace the heaters.  | 23<br>years     | 4 years                 | 50% TW  |

| Table 4-20  |
|---|
| OE captures for closed cooling water HX – 2001–2007, Part 1 |

| Case | Date      | Heat<br>Exchanger                                      | Material           | Diameter/Wall          | Event   | Testing Method                           |
|------|-----------|--|--------------------|------------------------|---|--|
| 84   | 4/4/2007  | Component<br>cooling water<br>HX                       | Brass              | 5/8"/0.049"            | Tube pits 75%<br>TW in 18<br>months   | ECT and destructive analysis             |
| 85   | 2006      | Stator cooling<br>HX 1A                                | CuNi 90/10         | 3/4"/18 BWG-<br>0.049" | Tube pitting  | ECT and destructive analysis             |
| 86   | 8/23/2005 | Turbine<br>building closed<br>cooling water<br>HX      | CuNi 90/10         | 3/4"/0.049"            | Tube leaks<br>100% TW in<br>12 months –<br>No passivation<br>after tubes<br>installed | Chemistry                                |
| 87   | 6/29/2004 | Reactor<br>building closed<br>cooling water<br>HX – 3B | Admiralty<br>brass | N/C                    | Tube leaks  | Air test, ECT                            |
| 88   | 4/16/2004 | Component<br>water cooling<br>HX                       | CuNi 90/10         | N/C                    | Tube cracking   | Component<br>cooling water<br>tank level |
| 89   | 6/20/2002 | Component<br>water cooling<br>HX                       | N/C                | N/C                    | Tube leak   | ECT                                      |
| 90   | 5/13/2002 | Component<br>water cooling<br>HX                       | N/C                | 0.050"                 | Tube pin hole<br>leaks  | ECT                                      |
| 91   | 5/2/2002  | Component<br>water cooling<br>HX                       | N/C                | N/C                    | Circumferential<br>tube cracks<br>not detected<br>by Bobbin<br>ECT                    | Visual                                   |
| 92   | 9/23/2002 | Turbine<br>building closed<br>cooling water<br>HX      | Admiralty<br>brass | 5/8"/18 BWG-<br>0.049" | Tubes found<br>severely<br>corroded   | ECT                                      |
| 93   | 2/14/2002 | Recirculating<br>cooling water<br>HX                   | N/C                | N/C                    | Extensive tube pitting  | ECT                                      |

1" = 25.4 mm

### Heat Exchanger OE Surveys

#### Table 4-21 OE captures for closed cooling water HX – 2001–2007, Part 2

| Case | Date      | Morphology  | Service<br>Life        | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|---|------------------------|-------------------------|----------------------|
| 84   | 4/4/2007  | Underdeposit corrosion due to low-flow velocity (< 1 ft/sec) caused high pitting growth rates – ECT undersized pits – Changed flush cleaning (5–6 ft/s) to every 12 weeks from 18-month period and revised ECT technique or plug criteria until corrosion mitigated.  | 75%<br>TW/18<br>months | 1.5 years               | N/C                  |
| 85   | 2006      | Underdeposit corrosion due to low-flow<br>velocity (< 1 ft/sec) caused high pitting growth<br>rates. ECT was found to undersize pits<br>because a custom calibration standard was<br>not used. Changed flush cleaning (5–6 ft/s) to<br>every 12 weeks from 18-month period and<br>revised ECT technique or plug criteria until<br>corrosion mitigated.  | 3 years                | N/C                     | N/C                  |
| 86   | 8/23/2005 | Turbine building closed cooling HX 90-10<br>CuNi tube leaks after one year of service<br>caused by underdeposit corrosion<br>(concentration cell and/or MIC); evidence of<br>denickelification was also found. Tubing ID<br>flow velocity is throttled down periodically to<br>< 3 ft/sec in winter months from its normal 4.5<br>ft/sec operation, which can lead to silt<br>deposits: EPRI indicated that CuNi 90/10 is<br>suspectible tp pitting for velocity, 3 ft/sec; also<br>limited 2 hr/day chlorination contributed to the<br>high pitting rate. Tube material is proposed to<br>be changed to SeaCure. | 1 year                 | 2 years                 | N/C                  |
| 87   | 6/29/2004 | ID inlet erosion, general ID wastage, ID pitting, and OD TGSCC.   | 30 years               | N/C                     | N/C                  |
| 88   | 4/16/2004 | Vibration fatigue cracking caused by high<br>shell-side flow velocity. Cracks initiated at inlet<br>stress-riser flow-accelerated-corrosion sites.<br>Tubes exhibited long unsupported spans. ET<br>DC2 probes examination inconclusive<br>because of circumferential crack assessment<br>limitation.   | N/C                    | N/C                     | N/C                  |
| 89   | 6/20/2002 | Tube leaks at turbine bldg CCW. Upon ECT<br>exam, many tubes showed OD support wear<br>caused by flow-induced erosion at the tube<br>support plates. Wall thinning exceeded criteria<br>so plug criteria was revised.   | N/C                    | N/C                     | N/C                  |
| 90   | 5/13/2002 | Underdeposit corrosion.   | 15 y                   | N/C                     | N/C                  |

#### Table 4-21 (Continued) OE captures for closed cooling water HX – 2001–2007, Part 2

| Case | Date      | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|--|-----------------|-------------------------|----------------------|
| 91   | 5/2/2002  | Circumferential SCC cracks on 50% of the tubes found at the tube transition near tubesheet – Inspection frequency: 18-months using bobbin coil ECT. ECT did not detect the cracks. | N/C             | 1.5 years               | N/C                  |
| 92   | 9/23/2002 | Admiralty brass HX tubes found severely<br>corroded due to using "wet-layup" procedure.<br>Corrosion damage occurred over a five-year<br>period.                                   | 5 year          | 1 year                  | N/C                  |
| 93   | 2/14/2002 | Upon ECT exam, extensive pitting was found caused by infrequent tube cleaning allowing fouling to accumulate.  | N/C             | N/C                     | N/C                  |

1 ft = 0.31 m

1 ft/s = 0.31 m/s

### 4.5 Residual Heat Removal HX OE Cases Captured

Nine OE captured cases for the residual heat removal HX were captured. The cases were by and large divided into two categories: tubing damage and gasket leakage. These events are summarized in Table 4-22.

### Table 4-22

Summary of OE captures for residual heat removal exchangers

| Material     | Damage   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type |
|--------------|--|-----------------|-------------------------|----------------------|--------------------|
| Tubing       |  |                 |                         |                      |                    |
| 304 SS       | Tube underdeposit corrosion including the U-bend region    | 13–16 y         | 8 y                     | N/C                  | ECT bobbin coil    |
|              | Tube wear (fretting) due to vibration in the U-bend region | N/C             | N/C                     | N/C                  | ECT bobbin coil    |
| Floating Hea | ad Gasket  |                 |                         |                      |                    |
|              | Corrosion of steel gasket jacketed with rubber             | 11 y            | No                      | No                   | No                 |
|              | Corrosion of soft iron gasket                              | 30 y            | No                      | No                   | No                 |

N/C = Not Captured

### Heat Exchanger OE Surveys

The tubing damage was reported due to underdeposit corrosion or OD wear. For the underdeposit corrosion cases, the tube pitting was reported due to manganese rich deposits. Pitting was detected by ET bobbin coil, and the damage was located both in the straight and U-bend tube sections. In this case, ET was reported to overestimate the pitting damage.

The tube OD wear reported was caused by high-flow velocity resulting in flow-induced tube vibration. The tube wear was detected by ET bobbin coil, and the damage was located in the U-bend tube section.

Five cases of gasket leakage were captured, with four of these occurring in HXs of floating head design. Detection of the gasket damage was identified once the leakage had occurred, either by detection of radio nuclides in the cooling water or by noticing corrosion of the HX studs.

One case was captured on coating failure in the cooling water side. The disbondment was caused by the "cold wall effect," which typically depends on the temperature differential and temperature cycles.

Tables 4-23 and 4-24 list the details of the residual heat removal HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

| Case | Date       | Material  | Diameter/Wall | Event   | Testing Method                              |
|------|------------|---|---------------|---|---|
| 94   | 10/30/2011 | Gasket: steel<br>jacketed with<br>nitrile rubber          | N/C           | Gasket failure  | Chemistry                                   |
| 95   | 11/1/2010  | Carbon steel  | N/C           | Coating failure                                       | Visual                                      |
| 96   | 6/15/2010  | Carbon steel  | N/C           | Gasket failure  | Abnormal pressures,<br>leak test, borescope |
| 97   | 3/13/2010  | N/C   | N/C           | Tube wear (no<br>leaks)                               | ECT   |
| 98   | 4/25/2009  | Gasket  | N/C           | Gasket failure  | Chemistry sampling                          |
| 99   | 4/17/2005  | Soft iron gasket  | N/C           | Gasket failure  | Chemistry                                   |
| 100  | 3/13/2003  | 304 SS  | 1"/0.049"     | Tube pits   | ECT   |
| 101  | 2/1/2003   | N/C   | N/C           | U-bend tube<br>pits                                   | ECT   |
| 102  | 1/8/2003   | Carbon steel-SA<br>193 bolts – gasket<br>flexitallic type | N/C           | Gasket<br>degraded leak<br>caused studs'<br>corrosion | Visual                                      |

| Table 4 | 1-23   |     |          |      |         |     |        |   |
|---------|--------|-----|----------|------|---------|-----|--------|---|
| OE cap  | otures | for | residual | heat | removal | HX, | Part ' | I |

1'' = 25.4 mm

Table 4-24 OE captures for residual heat removal HX, Part 2

| Case | Date       | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|--|-----------------|-------------------------|----------------------|
| 94   | 10/30/2011 | Inner head gasket failure in floating head HX design. Gasket type: steel jacketed with nitrile rubber.   | 11 years        | N/C                     | N/C                  |
| 95   | 11/1/2010  | Damage: coating, ARCOR type, became<br>disbonded on the service water side head<br>cover and channel head. Coating<br>disbondment caused by "cold wall effect"<br>which depends on the temperature<br>differential and temperature cycles. The<br>coating service life was 15 years. Reference:<br>NRC IN 97-013.  | 15 years        | N/C                     | N/C                  |
| 96   | 6/15/2010  | Floating inner head gasket leak caused by corrosion of the flange face or failure of the seal ring.  | N/C             | N/C                     | N/C                  |
| 97   | 3/13/2010  | Tubing vibration-induced fretting in the U-<br>bend region caused by high flow rate > 894<br>gpm. Damage measured by ECT. No tubes<br>found leaking, but some were plugged.  | N/C             | N/C                     | N/C                  |
| 98   | 4/25/2009  | Reactor coolant leakage caused by corrosion of the floating head gasket and gasket seating surface.  | N/C             | N/C                     | N/C                  |
| 99   | 4/17/2005  | Reactor coolant leakage caused by corrosion<br>of the floating head soft iron gasket and<br>gasket seating surface at the head/tubesheet<br>interface in the RHR HX 2A. Gasket replaced<br>with a modified split-ring and seal weld<br>design.   | 30 years        | N/C                     | N/C                  |
| 100  | 3/13/2003  | Pitting found with ECT caused by<br>manganese-rich underdeposit corrosion<br>primarily in the U-bend section. Last cleaning<br>and inspection performed in 4/15/95, eight<br>years ago. Manganese-rich deposits<br>removed by mechanical cleaning and<br>inspection and cleaning frequency increased.<br>Hydrolyzing cleaning found ineffective. ET<br>oversized pit depths. | 13 years        | 8 years                 | N/C                  |

### Table 4-24 (Continued) OE captures for residual heat removal HX, Part 2

| Case | Date     | Morphology  | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|----------|---|-----------------|-------------------------|----------------------|
| 101  | 2/1/2003 | Tube pitting found in U-bend section with<br>ECT caused by MIC/underdeposit corrosion.<br>38% of tubes plugged. Tubes never<br>inspected or cleaned prior to 2002. Heat<br>exchanger mostly operated in standby mode.<br>Going forward, water conductivity monitored<br>and flushed when alert range is reached.  | 16 years        | N/C                     | N/C                  |
| 102  | 1/8/2003 | 80% of SA 193 carbon steel HX studs found<br>corroded by boric acid attack. Gasket leak<br>caused the boric acid accumulation. The leak<br>was due to repeated heating and cooling of<br>gasket. The flexitallic gasket lost its filler<br>material and caused relaxation of the joint.<br>The original gasket was then replaced with a<br>graphite Flexpro gasket. After this gasket<br>was replaced, another leak occurred<br>because the proper hot retorquing was not<br>done on the bolting. | 25 years        | N/C                     | N/C                  |

1 gpm = 3.8 lpm

### 4.6 Seal Oil Cooler HX OE Cases Captured

As was mentioned in Section 3.2, seal oil coolers are typically small straight-shell-and-tube HXs with the seal oil flowing in the shell side and cooling water in the tube side. The HXs cited had admiralty brass, Copper SB75 and CuNi 90/10 tubing. These events are summarized in Table 4-25.

|                    | 1                                      |                 |                         | 1                    | 1                  |
|--------------------|--|-----------------|-------------------------|----------------------|--------------------|
| Material           | Damage                                 | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria | Inspection<br>Type |
| Admiralty<br>brass | Tube aggressive underdeposit corrosion | 6 y             | 1.5 y                   | 60% TW               | ECT bobbin coil    |
|                    | Tube ID inlet erosion                  | 3.5 y           | 1 y                     | N/C                  | Visual             |
| Copper<br>SB75     | Tube ID erosion                        | 3–8 y           | N/C                     | N/C                  | N/C                |
| CuNi 90/10         | Tube underdeposit corrosion            | 10–40 y         | N/C                     | N/C                  | ECT bobbin coil    |
|                    | Tube aggressive underdeposit corrosion | 0.3–3 y         | N/C                     | N/C                  | ECT bobbin coil    |
|                    | Tube OD wear at the tubesheet          | 30 y            | N/C                     | N/C                  | ECT bobbin coil    |

Table 4-25

Summary of OE captures for residual heat removal exchangers

N/C = Not Captured

For admiralty brass, the aggressive underdeposit corrosion conditions were due to the water having low pH and high oxygen concentration and a low ID water velocity. The tube ID inlet erosion was caused by high water velocity.

For copper tubing, the ID erosion was also caused by high water velocity, but, in addition, entrained particles were reported to have contributed to the wall loss damage.

The CuNi 90/10 tubing was reported susceptible to underdeposit corrosion and OD wear at the tubesheet supports. Premature tube failures were reported due to poorly developed oxide passivation layer and de-alloying in combination with low ID water velocity or stagnant flow conditions.

Tables 4-26 and 4-27 list the details of the seal oil cooler HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

| Case | Date      | Heat<br>Exchanger                                    | Material                                      | Diameter/Wall | Event   | Testing Method            |
|------|-----------|--|---|---------------|---|---------------------------|
| 103  | 4/25/2012 | Seal oil cooler                                      | CuNi 90/10                                    | 1"/0.049"     | Cooler<br>failure –<br>major leak                   | Visual                    |
| 104  | 3/20/2012 | Air-side seal<br>oil cooler                          | CuNi 90/10                                    | N/C           | Tube<br>pitting (34<br>tubes –<br>26% of<br>bundle) | ECT                       |
| 105  | 3/14/2012 | HPCI room<br>cooler                                  | Copper<br>SB/B75 +<br>spiral<br>aluminum fins | 5/8"/0.025"   | Tube leaks  | N/C                       |
| 106  | 2/11/2011 | Lube oil<br>cooler                                   | Admiralty<br>brass                            | 0.025"/       | Tube leaks  | N/C                       |
| 107  | 4/21/2010 | Air-side and<br>hydrogen-<br>side seal oil<br>cooler | Admiralty<br>brass                            | N/C           | Tube<br>pitting                                     | ECT                       |
| 108  | 6/19/2009 | LPCI room<br>cooler                                  | Copper<br>SB/B75 +<br>aluminum fins           | 5/8"/0.025"   | Tube leaks  | N/C                       |
| 109  | 6/8/2009  | Drywell chiller<br>44A                               | CuNi 90/10 -<br>Fins                          | 0.75"/0.049"  | Tube leaks<br>at non-<br>finned<br>areas            | ECT                       |
| 110  | 9/11/2006 | Standby lube oil cooler HX                           | CuNi 90/10                                    | N/C           | Multiple<br>tube leaks<br>(20–30)                   | Oil found with water, ECT |

### Table 4-26 OE captures for seal oil cooler HX, Part 1

### Table 4-26 (Continued) OE captures for seal oil cooler HX, Part 1

| Case | Date       | Heat<br>Exchanger              | Material                               | Diameter/Wall | Event   | Testing Method                |
|------|------------|--------------------------------|--|---------------|---|-------------------------------|
| 111  | 3/14/2006  | EHC cooler                     | CuNi 90/10                             | 3/8"/0.025"   | ET indications<br>– 58% deep<br>max                 | ECT                           |
| 112  | 12/20/2003 | Lube oil<br>coolers 1A &<br>2C | Admiralty<br>brass                     | 0.375"/0.025" | Tube leaks  | Oil condition in pump gearbox |
| 113  | 7/1/2003   | Stator cooler                  | CuNi 90/10                             | 5/8"/0.049"   | Tube pitting<br>due to<br>denickelification         | ECT                           |
| 114  | 11/19/2001 | Hydrogen<br>coolers            | CuNi 90/10<br>+ helical<br>copper fins | 3/4"/0.049"   | Tube pitting<br>due to<br>incomplete<br>passivation | ECT                           |

1″ = 25.4 mm

- -

#### Table 4-27 OE captures for seal oil cooler HX, Part 2

| Case | Date      | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|-----------|--|-----------------|-------------------------|----------------------|
| 103  | 4/25/2012 | Generator seal oil cooler with finned tubes<br>and dual floating tubesheet had a leak due<br>to tube thinning and tubesheet<br>displacement. The cooler had never been<br>ET tested.   | 30 years        | N/C                     | N/C                  |
| 104  | 3/20/2012 | Recently replaced tubes in a particular<br>bundle were found severely ID pitted with<br>26% of tubes exhibiting wall loss > 50%<br>upon ET examination. The rapid corrosion<br>was due to poorly developed oxide<br>passivation layer contaminated with foreign<br>material and low ID water velocity<br>conditions that promoted underdeposit<br>corrosion. | 4 months        | N/C                     | N/C                  |
| 105  | 3/14/2012 | Internal wall thinning due to erosion caused<br>by high flow velocity. Wall thinning more<br>pronounced in the tube's bottom,<br>suggesting that entrained particles played a<br>role in the erosion.  | 8 years         | N/C                     | N/C                  |
| 106  | 2/11/2011 | Tubes leaked due to tube ID inlet erosion corrosion caused by high ID flow velocity.   | 3.5 years       | N/C                     | N/C                  |

### Table 4-27 (Continued) OE captures for seal oil cooler HX, Part 2

| Case | Date       | Morphology   | Service<br>Life           | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|--|---------------------------|-------------------------|----------------------|
| 107  | 4/21/2010  | Tubes found severely ID pitted with some<br>tubes exhibiting wall loss > 60%. The tubes<br>had been in service for six years and had<br>been cleaned and visually inspected every<br>18 months. The rapid corrosion was due to<br>the water having low pH/high oxygen and ID<br>low-velocity conditions that promoted<br>underdeposit corrosion. | 6 years                   | N/C                     | 60%                  |
| 108  | 6/19/2009  | Internal wall thinning due to erosion. Since<br>nominal ID flow velocity was < 4 ft/s, the<br>erosion may have been caused by<br>entrained particles. Wall thinning was more<br>pronounced in the tube's bottom,<br>suggesting that entrained particles did play<br>a role.  | 3 years                   | N/C                     | N/C                  |
| 109  | 6/8/2009   | Tube leaks in non-finned areas caused by<br>long-term, underdeposit pitting corrosion.<br>Non-finned areas exhibited larger ID<br>(0.652") than finned areas (0.567"). Variable<br>ID affected performance of ET. ET did not<br>detect the tube leaks.   | 40 years                  | N/C                     | N/C                  |
| 110  | 9/11/2006  | Tubes were found with multiple leaks (20–30) due to dealloying. ET examination found the tubes extensively ID pitted. The rapid corrosion was due to the improper passivation and contamination during installation causing dealloying. Low, throttled down, velocity conditions (5%–10%) during layup times also contributed to the corrosion.  | 3 years                   | N/C                     | N/C                  |
| 111  | 3/14/2006  | De-alloying resulting in internal pitting caused by low-flow velocity (< 5 ft/s) or stagnant conditions.   | 3 years                   | N/C                     | N/C                  |
| 112  | 12/20/2003 | Tubes leaked due to tube ID inlet erosion<br>corrosion caused by zinc anode bloom<br>deposits that created turbulent flow<br>conditions. Excessive buildup from zinc<br>anode corrosion deposits that cause<br>blockage is considered the primary reason<br>for the failure.   | 5.75<br>and 8.25<br>years | N/C                     | N/C                  |

### Table 4-27 (Continued) OE captures for seal oil cooler HX, Part 2

| Case | Date       | Morphology   | Service<br>Life | Inspection<br>Frequency | Plugging<br>Criteria |
|------|------------|--|-----------------|-------------------------|----------------------|
| 113  | 7/1/2003   | Localized pitting due to denickelification<br>40% deep. ETC indications accurately<br>depth sized. Pit growth rate determined to<br>be slow. HX was drained and dried while<br>idle. | 10 years        | N/C                     | N/C                  |
| 114  | 11/19/2001 | Incomplete passivation caused by use of chloride and hypochloride. ETC indications up to 100% TW.  | 2 years         | N/C                     | N/C                  |

1 ft/s = 0.31 m

1" = 25.4 mm

### **5** HEAT EXCHANGER NDE PERFORMANCE CAPTURED CASES

In addition to the tubing integrity cases described in Section 4, the survey also captured cases where the NDE performance was documented.

The cases were limited to tubing examination with an ET bobbin coil. These cases compared the ET measurement with the metallurgical laboratory assessment obtained by sectioning the tube and analyzing the damage at the location of the call. The comparison is considered useful in that it points to areas were the NDE procedures may need improvement, while assisting in the design of mockups for examination procedure validation. However, this work did not investigate the NDE procedures used in detail to identify any improvements that might be warranted. That task will be the subject of a future work scope.

### 5.1 Condenser NDE Performance Captured Cases

A summary of the ET performance cases in condenser examination are listed in Table 5-1. As indicated in the table, the tubing material in these cases was 304 SS.

| Case | Heat<br>Exchanger | Material | Diameter | Damage  | ET Performance                             |
|------|-------------------|----------|----------|---|--|
| 115  | Condenser         | 304 SS   | 1"       | Wear in the support plate                     | Depth<br>overestimated                     |
| 116  | Condenser         | 304 SS   | 1"       | Fatigue linear cracks at the tube's weld seam | Depth<br>overestimated                     |
| 117  | Condenser         | 304 SS   | 0.75"    | Seam weld lack of fusion                      | Depth<br>overestimated                     |
| 118  | Condenser         | 304 SS   | 1"       | Circumferential cracks                        | Not detected                               |
| 119  | Condenser         | 304 SS   | 1"       | OD droplet impingement                        | Not detected or<br>depth<br>underestimated |

 Table 5-1

 Summary of captured ET condenser examination performance cases

1'' = 25.4 mm

The data captured are detailed next in the order listed in the table.

ET was found to overestimate the depth of tube wear damage near the tube support plate by 54%. ET estimated 61% wall loss while the measured damage was 7%.

Also, ET was found to overestimate the depth of fatigue linear cracks at the tube weld seam by an average of 17% and a maximum difference of 28%. The comparative data are listed in Table 5-2.

#### Table 5-2 Comparison between ET depth estimates and laboratory measurements in condenser tubing with linear fatigue cracks at the weld seams

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 99%                         | 71%                       |
| 2          | 85%                         | 68%                       |
| 3          | 95%                         | 71%                       |
| 4          | 59%                         | 60%                       |
| 5          | 83%                         | 75%                       |
| 6          | 67%                         | 39%                       |
| Average    | 81%                         | 64%                       |

In addition, ET was found to overestimate the depth of seam weld lack-of-fusion fabrication defects by an average of 43% and a maximum difference of 67%. Laboratory analysis identified the flaws as fabrication defects not caused by in-service conditions. The comparative data are listed in Table 5-3.

### Table 5-3

### Comparison between ET depth estimates and laboratory measurements in condenser tubing with lack of fusion defects at the weld seams

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 99%                         | 54%                       |
| 2          | 99%                         | 32%                       |
| 3          | 97%                         | 48%                       |
| 4          | 52%                         | 34%                       |
| Average    | 87%                         | 42%                       |

ET was found to be not effective at detecting circumferential cracks near tube support plates. However, it was reported that the circumferential cracks were detected with Matrix and motorized rotating pancake coil (MRPC) probes.

ET was found to be not effective at detecting through-wall leak locations caused by OD droplet impingement. It was reported that the small ID size of the pinhole in combination with the presence of erosion and other pitting damage in the vicinity location contributed to the ET current performance difficulties. Table 5-4 documents the ID and OD pinhole openings and associated erosion depths for the cases captured.

| Indication | OD Width<br>(Inch) | ID Width<br>(Inch) | Erosion Wall Loss |
|------------|--------------------|--------------------|-------------------|
| 1          | 0.027              | 0.006              | 14%               |
| 2          | 0.015              | 0.005              | 32%               |
| 3          | 0.020              | 0.005              | 21%               |
| 4          | 0.020              | 0.007              | 18%               |

### Table 5-4 Pinhole size and erosion depth due to OD droplet impingement in condenser tubing

1″ = 25.4 mm

In a separate droplet impingement damage case, ET was again found to be not capable of identifying the leak locations while underestimating the wall loss. Pit depth was underestimated on average by 22%, exhibiting a maximum difference of 34%. The pinholes were located in erosion-affected areas near tube support plates. The comparative data are listed in Table 5-5.

# Table 5-5Comparison between ET depth estimates and laboratory measurements in condensertubing with droplet impingement damage

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 80%                         | 100%                      |
| 2          | 85%                         | 100%                      |
| 3          | 51%                         | 85%                       |
| 4          | 90%                         | 100%                      |
| Average    | 77%                         | 96%                       |

### 5.2 Feedwater Heater NDE Performance Cases Captured

A summary of the ET examination performance cases in feedwater heater examinations is listed in Table 5-6.

### Table 5-6 Summary of captured ET feedwater heater examination performance cases

| Case | Heat Exchanger   | Material | Damage               | ET Performance          |
|------|------------------|----------|----------------------|-------------------------|
| 120  | Feedwater Heater | 304 SS   | Fabrication defects  | False calls             |
| 121  | Feedwater Heater | 304 SS   | OD transgranular SCC | Accurate depth estimate |

Five false indications were reported in the captured cases. Upon performing laboratory analysis, the indications were identified as "lap" type fabrication defects. The ET signal response from these lap defects incorrectly assessed their depth ranging from 87% to 96%.

Heat Exchanger NDE Performance Captured Cases

Three axial transgranular stress corrosion cracks (TGSCCs) were also reported. TGSCC flaws normally occur as a result of tubing exposure to chlorides in the presence of water. The laboratory analysis identified the cracks as having multiple branches. The ET depth assessment of the cracks was found to be accurate.

The comparative data are shown in Table 5-7.

#### Table 5-7 Comparison between ET depth estimates and laboratory measurements in feedwater heater tubing with TGSCC damage

|                     |            | -                            |                              |
|---------------------|------------|------------------------------|------------------------------|
| Indication          | Damage     | Eddy Current Measured Depth  | Laboratory Measured<br>Depth |
| 1, 2, 3, 4,<br>5, 6 | False call | 87%, 93%, 90%, 93%, 83%, 94% | No wall loss                 |
| 7                   | TGSCC      | 80%                          | 65%                          |
| 8                   | TGSCC      | 75%                          | 85%                          |
| 9                   | TGSCC      | 88%                          | 90%                          |
| Average TGSCC       |            | 81%                          | 80%                          |

### 5.3 Closed Cooling Water HX NDE Performance Cases Captured

A summary of the ET examination performance cases in closed cooling water HX examinations is listed in Table 5-8.

Table 5-8

Summary of captured ET closed cooling water HX performance cases

| Case | Heat Exchanger           | Material           | Diameter | Damage   | ET Performance      |
|------|--------------------------|--------------------|----------|--|---------------------|
| 122  | Closed cooling<br>heater | Admiralty<br>brass | 3/4"     | ID erosion   | Depth overestimated |
| 123  | Residual heat<br>removal | Admiralty<br>brass | 1"       | Underdeposit corrosion<br>caused by manganese<br>deposits. | Depth overestimated |

### 1" = 25.4 mm

In these cases, ET was reported to overestimate the depth of ID inlet erosion and underdeposit corrosion. The tubing material was admirally brass.

For the ID inlet erosion case, ET overestimated the wall loss by 7% on average, exhibiting a maximum deviation of 31%. This ID inlet erosion damage was reported due to long periods of HX operation with cooling water velocity exceeding the 6 ft/sec (1.8 m/sec) threshold for admiralty brass. The comparative data are shown in Table 5-9.

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 45%                         | 50%                       |
| 2          | 83%                         | 73%                       |
| 3          | 31%                         | 23%                       |
| 4          | 64%                         | 62%                       |
| 5          | 45%                         | 48%                       |
| 6          | 38%                         | 27%                       |
| 7          | 36%                         | 37%                       |
| 8          | 56%                         | 25%                       |
| 9          | 45%                         | 43%                       |
| 10         | 57%                         | 37%                       |
| 11         | 52%                         | 46%                       |
| Average    | 50%                         | 43%                       |

#### Table 5-9

Comparison between ET depth estimates and laboratory measurements in closed cooling water HX admiralty brass tubing with ID inlet erosion damage

For the underdeposit corrosion case, ET overestimated the wall loss by 32% on average and a maximum deviation of 51%. The damage was reported due to manganese deposits that resulted in ID pitting, exhibiting a "closed-tunneling" morphology rather than wall loss. The latter morphology was cited as a reason for the large discrepancy between ET and the laboratory assessment. The comparative data are shown in Table 5-10.

### Table 5-10

### Comparison between ET depth estimates and laboratory measurements in closed residual heat removal HX admiralty brass tubing with underdeposit corrosion damage

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 89%                         | 57%                       |
| 2          | 86%                         | 35%                       |
| 3          | 83%                         | 43%                       |
| 4          | 37%                         | 34%                       |
| Average    | 74%                         | 42%                       |

Heat Exchanger NDE Performance Captured Cases

### 5.4 Seal Oil Cooler NDE Performance Case Captured

One ET examination performance case was captured for seal oil cooler HXs. This case is summarized in Table 5-11.

### Table 5-11Summary of captured ET seal oil cooler HX performance case

| Case | Heat Exchanger     | Material   | Diameter | Damage                 | ET Performance          |
|------|--------------------|------------|----------|------------------------|-------------------------|
| 124  | Seal oil cooler HX | CuNi 90/10 | 3/8"     | Underdeposit corrosion | Accurate depth estimate |

1'' = 25.4 mm

In this case, the laboratory evaluations found the ID pit depths to be within the range measured by ET. The damage was found to be caused by underdeposit corrosion in combination with dealloying. This mechanism is normally caused by low or stagnant flow conditions. The comparative data is shown are Table 5-12.

### Table 5-12

### Comparison between ET depth estimates and laboratory measurements in a seal oil cooler HX CuNi 90/10 tubing with underdeposit corrosion damage

| Indication | Eddy Current Measured Depth | Laboratory Measured Depth |
|------------|-----------------------------|---------------------------|
| 1          | 45%–58%                     | 52%                       |
| 2          | 43%–58%                     | 48%                       |

# 6 CONCLUSIONS

This work captured 124 BOP HX operating experiences to assist in inferring NDE effectiveness and HX tubing material performance.

The cases captured addressed events in condensers, feedwater heaters, emergency diesel generator HXs, closed cooling water HXs, residual heat removal HXs, and seal oil coolers.

The information captured was mapped into six categories for each HX service:

- Material
- Damage mechanism
- Inspection technique
- Service life
- Cleaning and inspection frequency
- Plugging criteria

The events included 10 NDE performance evaluation cases where the ET wall loss estimation was compared with laboratory analysis of the sectioned tube at the call location.

In this report, the captured data are presented in table form. It is recommended that future work be performed to fill the information gaps identified and to migrate the information to an online database query system with the capability of making parametric comparisons.

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