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July 31, 2008

In addition to the incident investigation, the following is a summary of the steps taken by the Department of Public Safety (Department) in the wake of the boiler failure on November 6, 2007.

1. On November 19, 2007 the certificates of inspection for all four boilers were revoked. This action prohibited the boilers from restarting until an inspection by Department inspectors was performed and a new certificate was issued.
2. The Department performed an assessment on all solid fuel fired boilers in the Commonwealth to ensure that other plants with solid fuel fired boilers were in compliance with the Code which required inspection and maintenance of the Dead Air Space in the boiler. The compliance action was carried out by all of the state District Engineering Inspectors on March 24, 2008. Based on this assessment, it was determined the other plants did comply with the Code in this regard.
3. Before any repairs were allowed to be performed on any of the boilers at the Salem Harbor Plant:
    a. The Department reviewed/discussed the proposed non-destructive examination (NDE) and repair scope with DENE-Salem;
    b. The Engineer-in-charge Steve Dulong of Dominion Energy New England (DENE-Salem) stepped down from his responsibilities as the Engineer-in-charge;
    c. Daniel Girard assumed the position of Engineer-in-charge.
4. The Department met with DENE-Salem management to review and discuss plant responsibilities with particular attention to the Engineer-in-charge.
5. The Department met with the new Engineer-in-charge to review plant responsibilities.
6. The Department requested DENE-Salem to perform operator training and create procedures to identify boiler tube leaks to ensure personnel safety in the event a leak is identified.
7. The Department formed a Boiler Task Group to consider and submit proposed changes to the Board of Boiler Rules as a result of the incident.
8. As boiler repairs and NDE proceeded, the Department discussed results on the NDE with DENE-Salem and in some cases increased the scope of NDE. It is noted that DENE-Salem also initiated decisions to increase the scope of NDE several times as well. A review of all the NDE and repairs are attached.
9. The Department ordered pressure tests of the boilers and inspected each boiler before each boiler was allowed to return to service.
10. On July 31, 2008, the Department revoked former Engineer-in-charge Steve Dulong's 1st Class Engineer's License.
11. On July 31, 2008, the Department advised Insurance Inspector Robert Maule that based upon the results of its investigation, it deemed him incompetent and untrustworthy to hold a Certificate of Competency to inspect boilers in the Commonwealth. Such finding may lead to the revocation of his Certificate of Competency.

Commonwealth of Massachusetts

Department of Public Safety

INCIDENT REPORT

July 31, 2008

Dominion Energy New England - Salem Harbor Station
Salem, MA
Boiler #3 Failure - November 6, 2007

Investigating Inspectors

Mark F. Mooney, Chief of Inspections – Mechanical
Edward S. Kawa, Manager of District Engineering Inspectors

INCIDENT FACT SHEET

DATE AND TIME: November 6, 2007, 0846 hours

LOCATION: Dominion Energy New England
Salem Harbor Generating Station
24 Fort Avenue
Salem, MA 01970
(978) 740-8234

VICTIMS / FATAL: Mathew Ideglia (deceased)
[redacted]

Philip Robinson (deceased)
[redacted]

Mark Mansfield (deceased)
[redacted]

OBJECT UNDER INVESTIGATION: 1957 B & W Boiler, NB #19517

MANUFACTURER: The Babcock & Wilcox Company
800 Main Street, 4th Floor
Lynchburg, VA 24505 U.S.A.
1-800-BABCOCK (1-800-222-2625)

WITNESSES: See Supplemental Interview List

INSPECTORS: Mark F. Mooney (lead inspector)
Edward S. Kawa

INVESTIGATING LOCAL POLICE: Detective John Doyle, Salem Police Department

INVESTIGATING STATE POLICE: Trooper Anthony LoPilato, Mass. State Police

INVESTIGATING OSHA INSPECTORS:
John Nesbitt, Industrial Hygienist
Alan Burbank, Compliance Safety and Health Officer
Lee Hathon, Mechanical Engineer

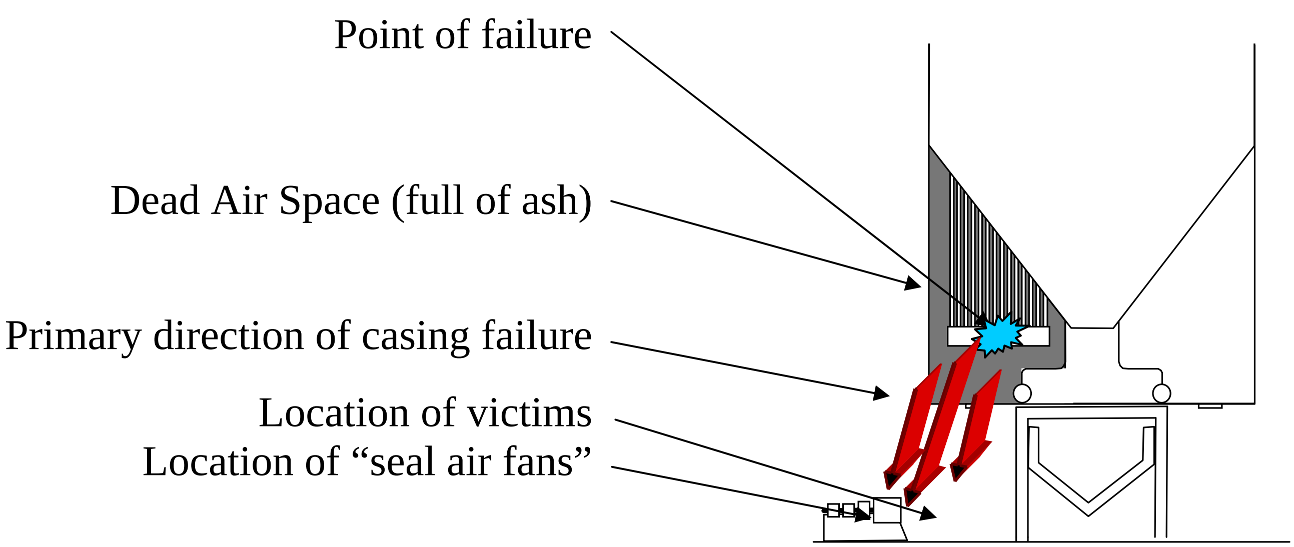
INCIDENT SUMMARY

On November 6, 2007 at approximately 0800 hours, two (2) operations employees (Mathew Indeglia, and Philip Robinson) and one maintenance employee (Mark Mansfield) were working to tag out a pulverizer seal air fan under boiler #3. At 0846 hours, a series of division wall tubes catastrophically failed within the east furnace lower slope dead air space. The steam boiler was operating at 1900 PSI at the time of the failure. The furnace lower slope dead air space was normally under a slight negative pressure. The failure of tubes within the furnace lower slope dead air space caused that space to become rapidly pressurized resulting in a secondary explosive rupture of the boiler casing around that space. It is believed that the tubes failed in a pattern and manner as shown in this report as “apparent pattern of failure”. The failure caused ash and steam/hot water, at a temperature of approximately 600°F, to be released toward the immediate area where the three employees were standing. Based on witness accounts, the three (3) employees were able to leave the area of the failure on their own, however, they all suffered extensive burn injuries. All 3 died within 24 hours of the explosion.

Autopsies on Matthew Indeglia, Mark Mansfield, and Phil Robinson were performed by Dr. John Parker of the Office of the Chief Medical Examiner. Dr. Parker determined that all three victims drowned in their own secretions as a result of damage to the bronchi, trachea and lungs. Dr. Parker also determined that each victim suffered significant burns.

As a result of the boiler failure, the boiler was immediately shut down and the facility managers began the process of shutting down the remaining 3 boilers. Due to the massive release of asbestos caused by the failure, the area was sealed off in accordance with the Division of Occupational Safety requirements.

On November 19, 2007, the Department revoked the certificate of inspection for boilers #1 through #4 in accordance with Massachusetts General Law Chapter 146. (See appendix 5)



Graphic representation of failure area

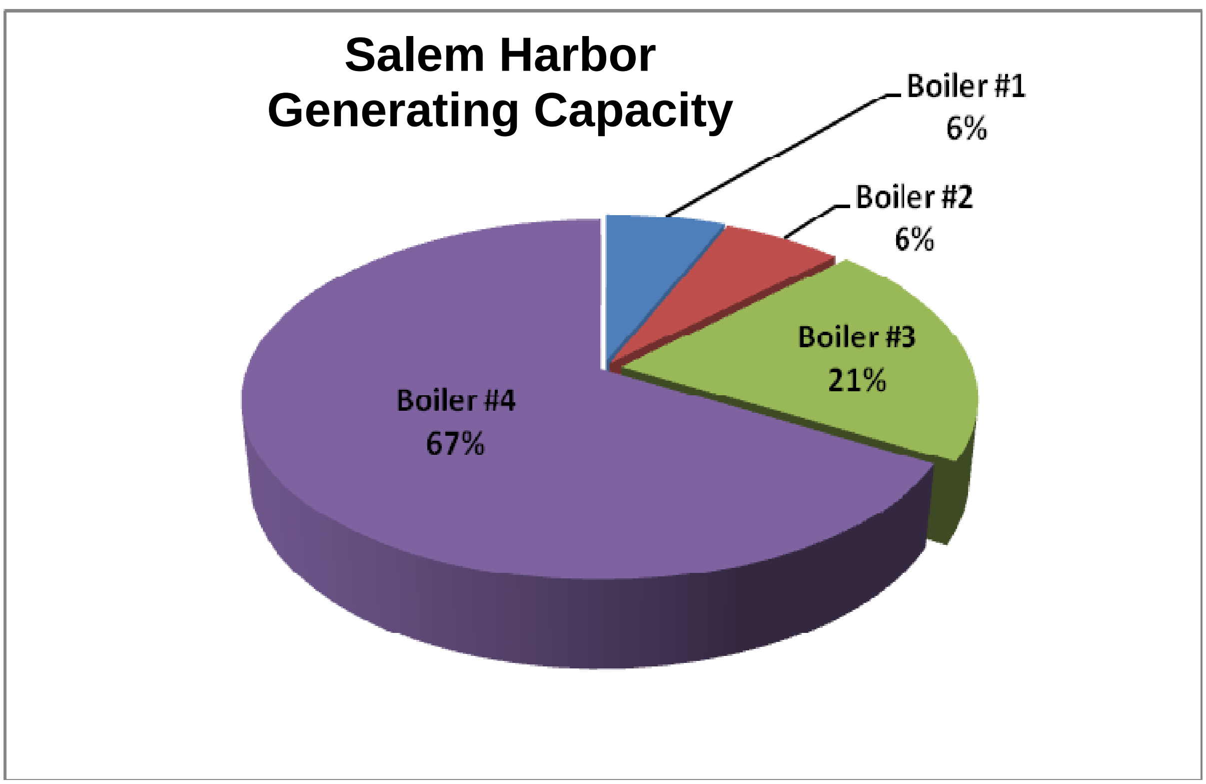
BACKGROUND INFORMATION

Based on information gathered in the investigation, Dominion Energy New England – Salem Harbor (DENE) is located at 24 Fort Avenue, Salem, Massachusetts. The facility is a 680 megawatt coal / oil fired power generating facility. The facility has 4 high pressure boilers, 3 of which can burn coal or oil and a 4th boiler which burns oil. Each boiler supplies steam to 4 individual steam turbines.

Boilers #1 and #2 are Babcock and Wilcox water tube steam boilers capable of producing 625,000 pounds of steam per hour. These boilers provide steam to a General Electric and a Westinghouse turbine generating a total of 120 megawatts.

Boiler #4 is a Riley Stoker water tube steam boiler which burns oil or natural gas, capable of producing 3,250,000 pounds of steam per hour. This boiler provides steam to a General Electric turbine generating a total of 436 megawatts.

Boiler #3, where the failure occurred, is a 1957 Babcock & Wilcox (B & W) water tube steam boiler, capable of producing 1,000,060 pounds of steam per hour. This boiler provides steam to a General Electric turbine generating a total of 125 megawatts. Boiler #3 was manufactured for the New England Power Company, and was placed into service on June 8, 1958. The boiler has been operating on a continuous basis since that time, being brought off line only for required inspections, maintenance and repair. Based on information obtained from previous inspection reports, as of November 2007, the boiler had been in service for an estimated 433,000 hours with approximately 364,000 hours in actual operation.



Boiler #3 was designed and erected by the Babcock & Wilcox Company in accordance with the requirements of Section I of the American Society of Mechanical Engineers (A.S.M.E.) Boiler and Pressure Vessel Code as well as Massachusetts Regulation 522 CMR at the time of construction. (See appendix 2 – Manufacturers Data Report)

Based on statements from plant managers and supervisors, the facility was purchased by Pacific Gas and Electric Corporation (PG & E) from New England Power Company. In 2005, Dominion Resources Inc. Virginia purchased the facility and it is now under the control of DENE.

The boiler is a natural circulation watertube boiler designed with a divided furnace, an economizer, a reheater and a radiant and convection superheater. The boiler was designed to fire coal but had an approximate ten (10) year period of firing oil in the 1970’s until it returned to coal firing in the 1980’s. It is equipped with 4 pulverizers that feed 4 fuel elevations that are located on the furnace front wall. Each elevation contains 4 burners. The boiler is rated at 1,000,060 pounds per hour steam flow with a maximum allowable working pressure of 2,275 PSI.

Based on witness accounts from Salem Harbor operations personnel interviewed, the boiler has seen increased boiler cycling from minimum load to full load since the mid 1990’s. Several witnesses stated that the boiler outages were reduced from 6 week outages down to 2 - 4 week outages. Witness accounts indicated that this made it difficult for the plant to take care of all the outstanding maintenance items and the plant went from a preventive maintenance mentality to “putting out fires.” Plant personnel indicated that they believed that deregulation reduced the parts inventory, which also had a negative impact on plant maintenance.

A review of DENE’s outstanding work orders demonstrated a large backlog of approximately 2,500 work orders on plant equipment.

Boiler #3 was constructed in 1957 by the Babcock and Wilcox Company. The boiler is considered a high pressure (operating at 2,000 PSI) water tube boiler, which utilizes coal as the primary source of fuel. The boiler is approximately 130 feet high, and hangs from the top of the building structure and expands down. The boiler is equipped with an economizer, which is a bank of tubes located in the boiler flue gas path designed to increase the boiler feedwater temperature before it enters the boiler. It also has a primary and secondary superheater that takes saturated steam from the steam drum, located at the top of the boiler, in order to supply high quality dry steam to the steam turbine. The boiler also has a reheat superheater, which takes steam from a stage in the steam turbine and reheats it. It is then returned back to the turbine.

The boiler has 4 waterwalls (tubes that are lined up to cover each of the 4 furnace walls). The boiler has 4 coal burner levels, each of which contain 4 burners (16 burners total). The boiler is equipped with 4 coal pulverizers. Each pulverizer supplies coal to 4 burners. Each burner mixes air with the coal, which is ignited as it exits the burner. The products of combustion heat the water in the waterwalls and then flow through the secondary superheater, reheat superheater, primary superheater and finally past the economizer and out through components that reduce plant air emissions.

The steam produced in the boiler supplies steam to a steam turbine that drives a generator, which generates electricity. After the steam has passed throught the turbine, the steam is condensed. The condensate is heated and pumped back into the boiler in one large steam/water loop.

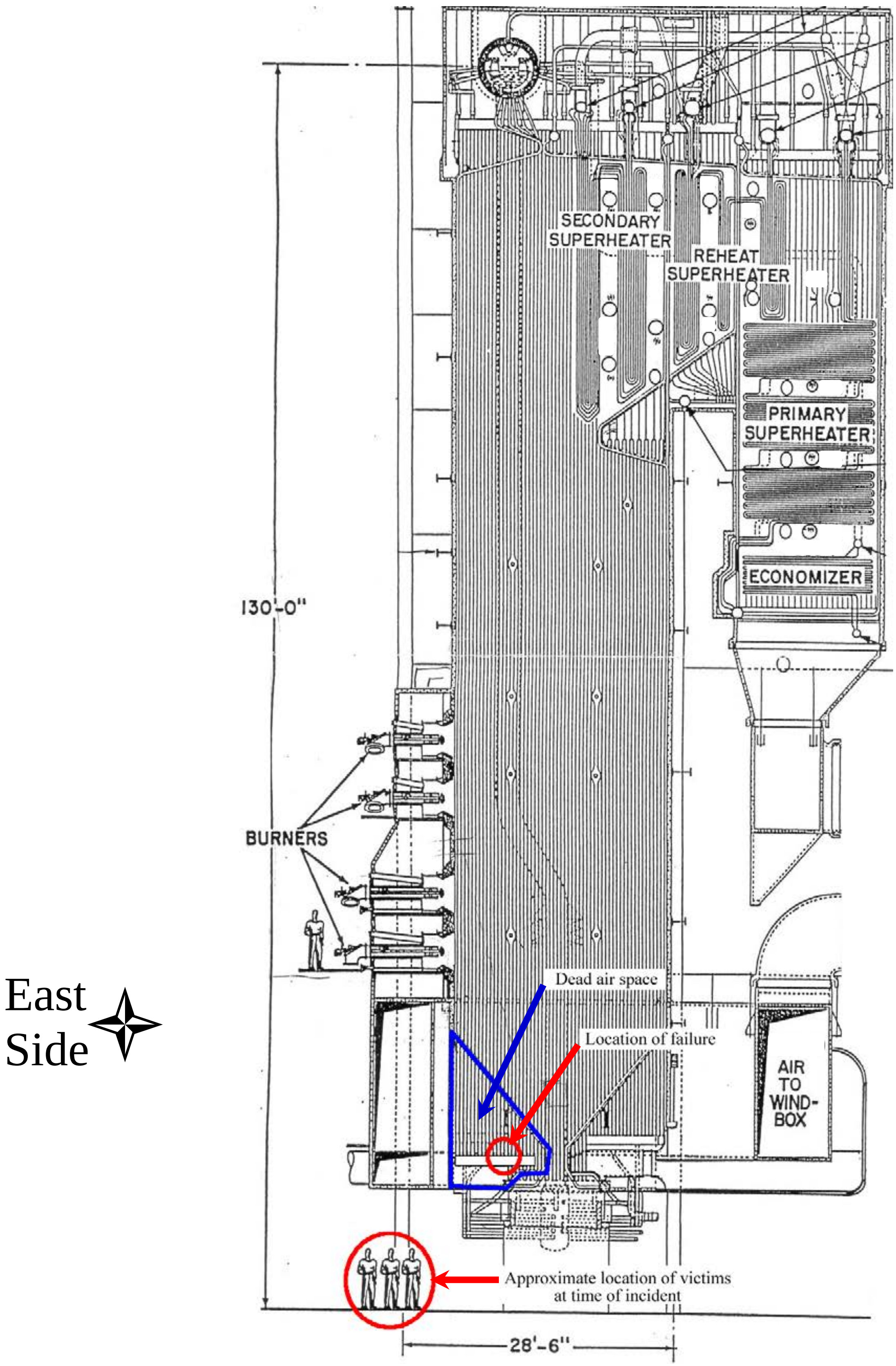
The boiler water is treated with chemicals to prevent component corrosion and to ensure that a high quality steam is produced.

The boiler runs under a balanced draft (the furnace pressure in the boiler is slightly negative). In order to maintain a balanced draft, the boiler is equipped with a forced draft fan that supplies air to the boiler, and an induced draft fan, which is located between the boiler and the stack. Fan dampers are used to maintain proper draft.

Because excess air results in improper combustion, “tramp air” (uncontrolled air entering the boiler from unintended locations) is minimized by a wet ash system. The waterwalls bend toward the bottom of the boiler to form a slope that directs the ash to a water filled hopper. The configuration of the waterwalls create a space within the boiler where there is no combustion. If properly maintained, the waterwalls are designed to minimize the amount of ash that accumulates in this space. This space is commonly referred to as a dead air space. If the spaces between the tubes are not tight or filled with a refractory material, boiler ash can fill the void space.

DENE, like most plants, use water to wash boilers down before an internal inspection. The dead air space is a location where water from water washing can enter and combine with the ash. This combination can become corrosive to metal if not cleaned or maintained periodically.

The following page gives a pictoral overview of this boiler.



Sketch #1 – Boiler #3 Overview

INCIDENT INVESTIGATION

On November 6, 2007 at 0846 hours, a catastrophic boiler failure occurred at the Salem Harbor Generating Station located at 24 Fort Avenue, Salem, Massachusetts. Within two hours, Massachusetts Emergency Management Agency Director Don Boyce notified the Department of a boiler explosion at the above location. A preliminary investigation was immediately started by Chief of Inspections-Mechanical Mark Mooney (Mooney) and assisted by Manager Edward S. Kawa (Kawa) and District Engineering Inspector Steve Bakas. The victims of the incident, Mr. Mathew Indeglia, Mr. Mark Mansfield, and Mr. Philip Robinson were given medical treatment on the scene and transported to local hospitals where they died from their injuries. The scene was secured by the Salem Police Department, and the State Police in conjunction with the Essex County District Attorney's Office (District Attorney's Office), OSHA and the Department of Public Safety.

The failure occurred in an area of the boiler that was insulated with asbestos. The failure dispersed the asbestos insulation and a large volume of ash throughout the boiler building. As a result, access to the failure location required specialized training and equipment. To assist in gaining immediate access to the point of failure, the State Fire Marshal, in cooperation with the Salem Fire Department, activated the hazardous material response unit in support of the Department of Public Safety's (DPS) investigation. The Massachusetts Division of Occupational Safety began working with the DENE Salem Harbor personnel to develop an asbestos abatement plan.

An initial observation of the failure was performed by Mooney and Kawa. It was determined that there were two short lengths of tube (tube stubs) missing from the ends of Tube #10 and Tube #11. These stubs were short sections of tube that were fitted into the lower division wall header and attached to the division wall tubes by a full penetration butt weld. These tube stubs separated from the tube and header adjacent to circumferential welds. The search of the missing tube stubs began shortly thereafter by the DPS in conjunction with the District Attorney's office, OSHA, and DENE. After an exhaustive search, the tube stub to tube #10 was located, buried in ash, in the approximate area where the victims' tool box was situated under the boiler. The tube stub to tube #11 has not been located as of the date of this report.

Following the initial inspection of the failed components, a large section of the header and the failed tube components were sent to a metallurgical lab (Structural Integrity Associates, Inc) for testing in Austin, Texas, under the oversight of the DPS. DENE produced volumes of documents requested by the DPS, OSHA and the District Attorney's office. Thirty nine individuals were brought in for questioning over the following months. (<u>See</u> Interview List in appendix).

Based on the interviews and documentation obtained in the investigation, it was determined that at approximately 08:00 a.m., two maintenance mechanics (Mark Mansfield and Dan Connolly) were working to lock out pulverizer seal air fan #3-1. They determined that this seal air fan could not be isolated for repair until a common discharge valve on seal air fan #3-2 was repaired. Mr. Mansfield went to the control room to get the proper lockout tags for seal air fan #3-2, while Mr. Connolly made a visit to the restroom. Two operators (Mathew Indeglia and Philip Robinson) then went down with Mr. Mansfield to lock out Seal Air Fan #3-2. As Mr. Connolly was leaving the restroom, the plant alarm sounded indicating a boiler failure. As the failure occurred, Mr. Mansfield, Mr. Indeglia and Mr. Robinson were in the area immediately below it. These men were able to exit the building, but had suffered serious and ultimately fatal burns from the failure.

Witness accounts gave no indication of any noticeable audible changes that could have warned adjacent operators or maintenance people in the area of a tube leak. It was determined, by both the discharge of the ash on the floor around the failure and the amount of ash buildup in the dead air space opposite the area where the failure occurred, that ash was packed in the space where the failure occurred. Further, several witnesses stated that it was common knowledge that the area was packed with ash. Ash can have a muffling effect on an adjacent tube leak, which are typically very loud. In addition, the area of the failure also had high operating noises caused by the coal pulverizers, which may have also affected the victims' ability to hear the leak.

Witness accounts and boiler operation trends show that Boiler #3 was routinely operated at a capacity above the rated steam flow for the boiler. Operating boilers above rated capacity can have a negative effect on the life of the boiler.

As part of the investigation, corrosion was considered as a possible cause. Based on witness testimony, it was the common practice to water wash the waterwalls when the unit was taken off line. The water would cascade to the lower section of the boiler including the lower dead air spaces. Water and ash are known to create a highly corrosive environment for boiler components.

The boiler also has an injection system that sprays a liquid chemical, Urea, into the furnace in an effort to reduce nitrous oxide emissions. Urea can mix with sulfur oxides to form ammonium bisulfates or ammonium sulfate compounds, which, based on my training and experience, is known to enhance corrosion and plugging in boiler air heaters.

Based on several witness accounts from the Salem Harbor operations personnel interviewed, it was common for the urea injection ports to overspray following a boiler trip. It was noted however that the substance was not present at the time of the first observation of the failed components several days following the failure.

Further, when the west side dead air space was opened, these tubes did not have any obvious signs of urea contamination. It was determined that the ash acted as an insulator from any excessive urea slip (urea overspray). Combined with the large volume of ash that was in the dead air space, and the time it takes for the Urea to leak down to the dead air space if not restricted by ash, the presence of the Urea was discounted as a significant factor in the failure. Mooney and Kawa determined that the corrosion of the tubes and header within the dead air space was caused primarily from the interaction of the boiler metal with the ash and water (from boiler washing).

As the investigation proceeded, Mooney made a determination that all 4 boilers at the Salem Harbor Station were in a dangerous condition. Upon this determination, on November 19, 2007, Mooney revoked the certificate of inspections from all 4 boilers at the plant. Massachusetts General Law Chapter 146 requires that a state inspection and pressure test must be performed on each boiler before a new certificate of inspection is issued. (See appendix 5). Since the shutdown, all the Boilers have undergone substantial non-destructive examination and/or repairs. They have been inspected by the DPS and have been issued new certificates of inspection. Boilers #1 and #2 were placed back into operation in May 2008 and Boiler #3 and #4 were placed back into service in July 2008.

BOILER #3 INSPECTIONS

Massachusetts General Law Chapter 146 section 6 states that "all steam boilers and their appurtenances … shall be thoroughly inspected externally and internally at least once a year."

In 2000, Massachusetts Board of Boiler Rules adopted the 1998 National Board Inspection Code (NBIC) with 1999 addenda, and incorporated them into 522 CMR. Massachusetts commissioned Insurance Inspectors are required to perform their inspections in accordance with the NBIC. The NBIC is the standard that Massachusetts licensed engineers are required to use to ensure their boilers are being maintained, repaired and inspected properly. As demonstrated further in this report, the boiler was not properly inspected in accordance with the NBIC code, nor was it inspected in accordance with the Manufacturer's manual.

Following a first inspection by a State District Engineering Inspector, the annual inspection is performed by an inspector of an insurance company. The responsibility of the insurance inspector is to make a proper internal and external inspection of the boiler, in accordance with Massachusetts regulations and the NBIC. If no discrepancies or unsafe conditions are found, the inspector shall issue a certificate of inspection.

In April 2007, Boiler #3 was brought down for annual inspection and maintenance. On April 10, 2007, Insurance Inspector Robert Maule (Maule), of National Union Fire Insurance Company, signed a certificate of inspection that he had performed the required inspection on Boiler #3 (See appendix 3). However, the lower dead air spaces containing the division wall headers were not opened for inspection at that time, and Maule's report made no reference to the condition of the furnace lower slope dead air space. (See appendix 11)

Based on statements made by Maule to Mooney and Kawa, on July 17, 2008, Maule stated that he did not inspect the dead air spaces on Boiler #3. He further stated that he did not inspect these spaces based on the fact that his personal past experiences never indicated these areas to be problem areas. He also stated that he looked in all boiler spaces early in his career but stopped this practice as his experience increased. Maule stated that since the failure, he has resumed inspecting all boiler spaces.

In April 2007, DENE also hired a second inspector (Dennis Nygaard of Alstom Power) to perform a private non-jurisdictional inspection as well. Mr. Nygaard indicated in his report that "no inspection was completed to the furnace lower slope dead air space this outage since it was not opened." (See appendix 4) All evidence demonstrates that the furnace lower slope dead air space had not been opened. During the entire interview process, no one could recall ever seeing, or having had seen evidence, that the furnace lower slope dead air spaces were opened. Engineer-in-charge Steve Dulong (Dulong) reported seeing documents that demonstrated that work had been performed in the furnace lower slope dead air space in approximately 1999, but did not actually recall seeing it open or anyone entering the space. He stated that the space had not been opened since he was the Engineer-in-charge. Another witness stated that he recalled seeing a report indicating that it had been opened in 1998,

When questioned regarding the failure to inspect the lower dead air spaces, Dulong stated that the space was not opened because Maule did not request the space to be opened.

Based on (1) the volume of ash that emptied into the area below the failure, (2) the volume of ash in the west side dead air space, (3) the level of corrosion on the tubes and header in the lower dead air space, and (4) the number of witnesses that confirmed the existence of ash in the lower dead air space, we determined that the lower dead air space was full of ash prior to the failure. To determine the volume of ash that was in the east dead air space in relation to the space, the DPS gained access to the dead air space opposite the space the failure occurred in. This space was virtually a mirror image of the area in which the failure occurred and was under the same operating conditions. This space (west side dead air space) could not be entered because of the heavily packed ash filling the space and blocking the entrance. The DPS ordered a channel in the ash, within the west side dead air space, be dug to gain a better view the current conditions of the space. The ash in the space was a mixture of fine ash and hardened solid rocklike form. The solid ash was broken up with poke rods and shovels and vacuumed out of the space. Mooney observed the space to be nearly full of ash, with the west side division wall header (directly opposite the one that was involved with the failure) completely encased in ash. The header and tubes on the west side had similar corrosion to that found on the east side. (See photos 42 – 53).

Compliance of other Boilers in the Commonwealth

In response to the Salem boiler explosion, the DPS identified thirty-three (33) other boilers at 16 locations across the Commonwealth that burned solid fuel with the potential of having dead air spaces where ash could build up and create a problem if not periodically inspected.

On Monday, March 24, 2008, the State District Engineering Inspectors were briefed on a compliance action, which occurred following the briefing.

The purpose of this compliance action was to identify all coal or solid fuel fired boilers in the Commonwealth and to determine if they had a current certificate of inspection, as well as determining if all of the spaces within the boiler that are accessible to an inspector had been opened at the time of inspection.

All of the facilities were visited by the end of the day. Only one facility could not immediately provide proper documentation, however it was able to produce the requested information the following day.

In all of the facilities, all of the confined spaces, including all dead air spaces, in all 33 boilers were opened and accessed within the past year. Of these boilers, twenty (20) of the 33 had dead air spaces. Based on this assessment, it was determined that all of the boilers listed that had spaces known to fill with ash had those spaces inspected within the past year.

January 2007 Leak

In January 2007, following a repair of a waterwall leak in Boiler #3, an additional leak was identified below the waterwall slope in the dead air space, as it enters the east side furnace lower slope dead air space. Based on witness accounts of maintenance personnel and the plant Quality Control Person Ken Brusgalis (Brusgalis), the plant cut tubes out of the waterwall to access the leak from the furnace side, due to the excessive ash buildup inside the furnace lower slope dead air space, which hindered access. According to Brusgalis, the cause of this leak was determined to be corrosion fatigue at a weld between the division wall and a membrane between the division wall and the waterwall slope. Brusgalis indicated that the plant did not look further to determine if the problem was an isolated problem or if the same condition existed at other locations. Dulong stated that he relied on others including Brusgalis to determine if further examination was necessary. Decisions such as this are the sole responsibility of the Engineer-in-charge.

Several witnesses including Dulong, stated that control room operators were trained by co-workers and did not go through a training program that would specifically educate them with the knowledge to be able to identify tube leaks, or which trends should be watched for possible indications of potential tube leaks. Dulong also stated that operators are not formally trained and that their training is "passed down from one guy to the next."

BOILER MANUFACTURER / EPRI BULLETINS

Startup / Shutdown Procedures

The Manufacturer (B & W) produced an operation and maintenance manual (Manual) for Boiler #3, which is common industry practice. This document provides directions on how to properly operate and maintain the boiler. Additionally, the Electric Power Research Institute (EPRI) conducts research and development on technology, operations and the environment for the global electric power sector, and provides helpful guides and bulletins to the power industry.

The Manual provides direction regarding shutdown procedures to ensure that the boiler is not cooled too quickly, which can create unnecessary and excessive thermal stresses on boiler components. Page 15 of the B & W Boiler manual, (<u>See</u> appendix 27) states, "[a]fter the firing equipment and fans are out of service, the dampers, including the superheater and superheater bypass dampers, when provided, should be closed in order to permit the unit to cool as slowly and uniformly as possible." It also goes on to state that "hastening the cooling of the furnace by allowing large quantities of cool air to pass through the setting tends towards brickwork difficulties and unnecessary stresses in the pressure parts."

Further, in quick shutdowns, the Manual cautions operators to "not permit the drum temperature difference to exceed the cooling cycle curve." (<u>See</u> appendix 29). The cooling cycle curve is shown in appendix 30. The Manual directs operators, on page 9, (<u>See</u> appendix 30) under "emergency shutdown" to "stop the primary air fan and close the primary air control damper" and "stop the force draft fan and close the force draft dampers" as well as "stop the induced draft fan and close the induced draft damper."

Based on witness statements, during boiler failures and shutdowns, plant control room operators admitted to cooling down the boilers without following manufacturer procedures and did not take measures to ensure the boilers were not cooled too quickly. Control room operators operating the boiler stated that it was common for them to leave fans on to hasten cooling in order to begin repairs sooner. Rapid temperature changes in boiler components create unnecessary and excessive thermal stresses on boiler components.

Inspections

The Manual also provides instructions for operators for routine inspections. On Page 17 of the Manual, (<u>See</u> appendix 31) it states "[i]n addition to routine operating inspections, a thorough inspection, from the viewpoint of safety, should be made yearly at the time of the visit of the Insurance Inspector or State Inspector. This should include a careful search for evidence of internal and external corrosion, leakage of seams, leakage of expanded, screwed or welded joints, evidence of overheating, and the condition of structural supports." It goes on to state "[i]t may be necessary to remove small sections of brickwork or casing to make such inspection complete, but it should be borne in mind that the parts which are most slighted, due to soot accumulation or difficulty of access, may be the very parts in which trouble will develop." The lower dead air space in which the failure occurred had excessive soot accumulation as well as being a difficult place to access. Neither Maule or Dulong ever opened or inspected this area.

The NBIC also requires that these areas be periodically cleaned and inspected. In accordance with the NBIC, part RB-9050, "the maximum period between internal inspections or a complete in-service evaluation of pressure retaining items shall not exceed one-half of the estimated remaining service life of the vessel or ten years, wherever is less". The method for estimating inspection intervals for exposure to corrosion is given in Part RB-9110 of the NBIC and is determined by the following formula:

$$\boxed{\frac{\text{Remaining life}}{\text{(years)}} = \frac{t_{(actual)} - t_{(required)}}{\text{corrosion rate}}}$$

DENE did not provide any documentation regarding any corrosion rates for any of the pressure parts, and did not have any documentation of this form for any of the components within the dead air spaces. Because this evaluation was not performed, the maximum period between internal inspections or complete in-service evaluations and remaining life could not have been properly determined.

EPRI Bulletins

In the 1980's, the industry developed guidelines for extending the boiler life (boiler life extension programs), including monitoring areas susceptible to failure for a variety of reasons such as corrosion, erosion or boiler stresses.

In May 2000, B & W issued the "Standard Recommendations for Pressure Part Inspection During a Boiler Life Extension Program" (BR-1701). It stated that lower temperature water and steam cooled headers are not susceptible to creep but may be damaged by corrosion, erosion, or severe thermal stresses. (<u>See</u> appendix 32) On page 5 of this document, it states that typical inspections of these headers consist of:

- Visual Inspection
- Wet Fluorescent Magnetic Particle – a WFMT inspection should be performed on welded attachments, handhold plugs, header end plate welds and 10% of tube to header welds.
- Video Probe Inspection – An internal visual inspection can be performed to locate internal problems.
- UTT – Should visual inspection reveal areas of wall loss from either corrosion or erosion, then ultrasonic thickness data may be taken to assess header thickness.

DENE did not provide any documentation on these lower headers that would demonstrate that any of these methods were used. During the interview process, Dulong indicated that he did not know about any life extension studies for Boiler #3.

BOILER TREND DOCUMENTATION

Based on my training and experience, when a boiler has a tube leak, it is common for certain operational trends to react in a particular manner. As more water is added to a boiler to compensate for the water lost through a leak, the amount of chemical concentration in a boiler will decrease unless action is taken to increase the chemical feed. The boiler makeup water volume increases, which can be seen in makeup trends. As a leak becomes more apparent, the rapid flashing of hot water to steam within the fireside area or section occupies a greater volume, therefore boiler induced draft fan dampers will open up in order to maintain the set furnace pressure. These automatic changes result in increased minor fluctuations in furnace pressure. As a leak progressively worsens, typically the boiler furnace pressure will become less stable.

Based on boiler trend information reviewed by the DPS, it was determined that the boiler failure began to cause some changes in trends approximately 3 weeks before the failure and became more apparent and progressively worsened to an irreversible condition approximately 45 minutes before the failure (See appendices 22, 23, 24, 25).

Although the leak was in a dead air space, there were sufficient gaps between the boiler waterwall and the dead air space for the leak to begin to show these typical fluctuations. As seen in appendix 23, the trends showed a slight decrease in boiler sodium and boiler pH, as well as a progressive increase in boiler water (hotwell) makeup and a change in the furnace pressure amplitude and frequency. This is a typical pattern leading to a failure. As previously explained, when a leak worsens, an automatic control valve (boiler hotwell makeup control valve) begins to open to allow new water into the boiler to compensate for water lost in the system. Boiler water can be lost though the normal operation of a boiler (such as through boiler blowdowns), but these normal conditions require operator knowledge and intervention. In viewing the boiler hotwell makeup control valve trend for the month prior to the failure, the trend showed an obvious change in frequency and volume beginning around October 20, 2007 and worsened in time. (See appendix 23)

Five days before the failure, the medium feedwater flow trend demonstrated a clear change in amplitude and frequency. (See appendix 25) As steam is introduced into the furnace space, it creates volumetric changes that have an effect on plant emissions. As a steam leak worsens, it can have an effect on boiler carbon monoxide (CO) and boiler opacity (visible smoke) emissions. A review of the Boiler #3 opacity also showed an increase in opacity in the six (6) hours prior to the failure. There were seven (7) low level spikes in opacity within the 8 hours prior to the failure. (See appendix 25) The boiler carbon monoxide emissions trends did not demonstrate anything that could have been singled out as a clear indicator, however the unexplained loss in boiler water should have been investigated. None of these trends were noticed by the plant personnel including Dulong.

METALLURGICAL FAILURE ANALYSIS

On December 7, 2007, Manager Edward Kawa escorted the failed components to the metallurgical test lab (Structural Integrity Associates) in Austin, Texas. The metallurgical testing occurred through the months of January and February 2008. In Structural Integrity Associates failure analysis of the boiler components from the lower dead air space, it was noted in the executive summary, that "there was no evidence uncovered during the examination of the header and tubing to indicate that either excessive wall thinning due to external corrosion, or waterside corrosion fatigue cracking, or base metal defects had played any role in the failure" (See appendix 6). However, in the technical summary, it explained that a hypothesis of the suspected cause of failure was one that the division wall nipple tubes had ruptured after losing a substantial amount of its original wall thickness due to external corrosion, and that "the defect grew in size, due to the interaction of corrosion and stress with intermittent discontinuities in the remaining intact ligament of weld metal, until it finally penetrated through the thickness of the weld and a small steam leak initiated." (See appendix 7).

In the "Visual Inspection I" portion of the report, under "external surfaces – corrosion", it states "it was apparent that both the header and tubes had suffered some measurable amount of wastage due to the external corrosion, with signs of widespread pitting attach visible on all surfaces." (See appendix 8).

In the "Visual Inspection II" portion of the report, under "results of EDS and XRD Analysis", it states "in all cases the deposit/scale accumulations were a mixture of elements associated with combustion by-products, such as sulfur, silicon, sodium, potassium, calcium, and iron oxides. The large amounts of sulfur and iron oxide are consistent with the observations regarding the surface corrosion, which was believed to have been caused by acid attack related to the wetting of reactive elements in the deposit, and particularly sulfur, during periods when the unit was not operating." (See appendix 9).

Also in the "Visual Inspection II" of this report, it describes "white-colored compound observed on Tube 5 identified as Urea. Witness accounts from the plant following the failure indicated that the injection of the urea had continued for some time after the unit had tripped off line, so that the presence of the urea in the deposit material appeared to be a secondary effect of the failure and was not considered in any way unusual." This is consistent with the DPS's findings.

Based on the full context of the metallurgical report, external corrosion accelerated the failure.

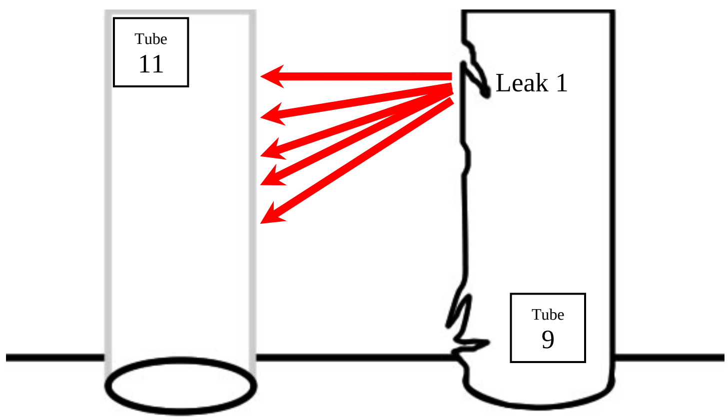
Based on boiler trend data and the physical damage of the components around the area of failure, it was evident that the boiler began to leak and progressively worsened over time until a catastrophic event occurred. Boiler leaks at this pressure create a significant and discernable sound. Since no witnesses heard any such sound, it is believed that the volume of packed ash within the space significantly muffled the sound of the leak making it indiscernible even when people were immediately adjacent to the leak. The high decibels of the coal pulverizers also aided in masking the muffled sound of the leak.

As confirmed in the metallurgical failure analysis, the failure began as a result of a weld defect at Tube 9, which grew in size due to corrosion and stress. The tube was also subjected to external corrosion, which decreased the thickness of the tubes. As a result of these mechanisms, a small leak initiated. The leak progressively worsened over time cutting adjacent tubes, which caused secondary leaks. The progressive thinning resulted in tube 10 and tube 11 catastrophically rupturing. The rapid release of 600 degree hot water at 1900 PSI into atmospheric pressure within the dead air space caused the water to flash to steam resulting in the rapid pressurization of the dead air space. The rapid pressurization of the dead air space caused the lower boiler casing within the dead air space to fail, releasing the full force of the failure to the area immediately below the boiler, where the victims were working.

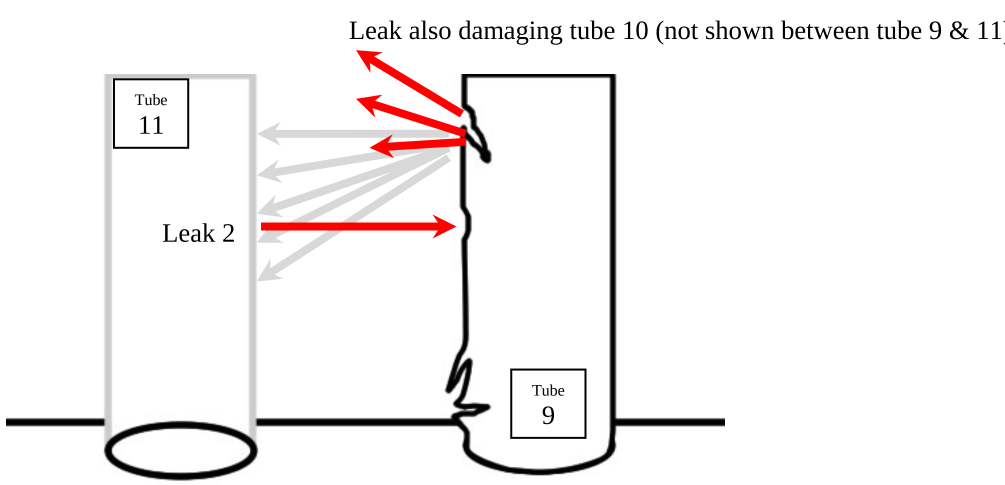
APPARENT PATTERN OF FAILURE

The following sketches present a graphic representation of the apparent series of events that explain the damage to the tubes involved in and leading up to the catastrophic failure. It is the opinion of the DPS that the initial leak began at a significant welding flaw and was exacerbated by stress and external corrosion. That leak caused a series of collateral damage to adjacent tubes, until the final catastrophic failure.

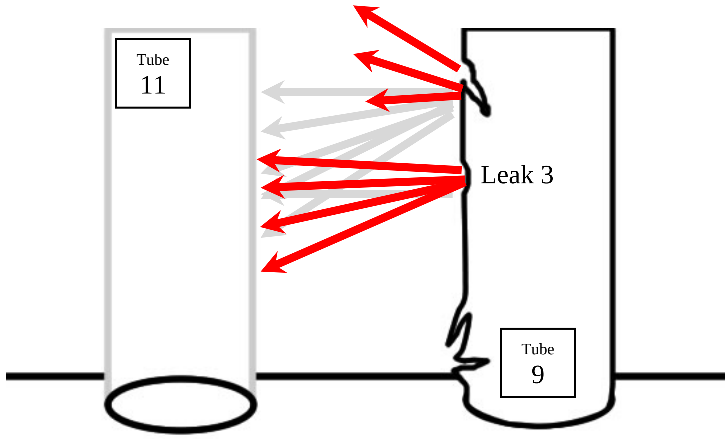
1. Tube 9 begins to leak as a result of a significant welding flaw at the time of manufacture, and external corrosion
   a. Leak strikes Tube 10 and 11 causing "collateral damage"



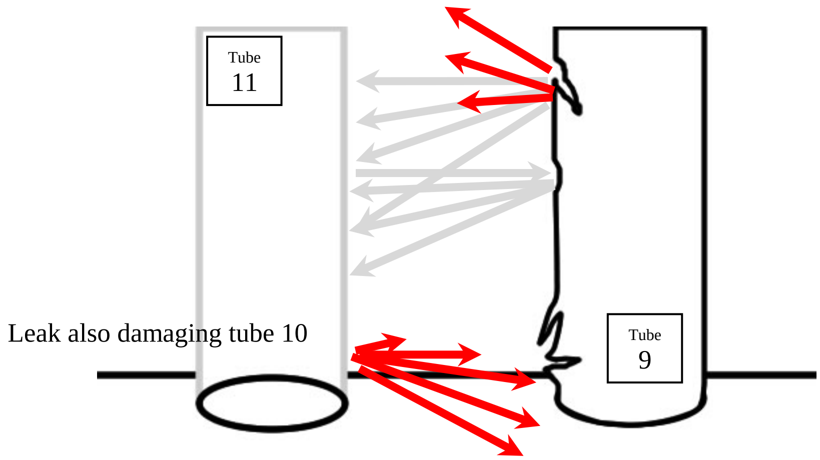
2. Initial leak in Tube 9 continues to damage Tube 10 and 11
   a. Tube 11 begins to leak and starts to damage Tube 9



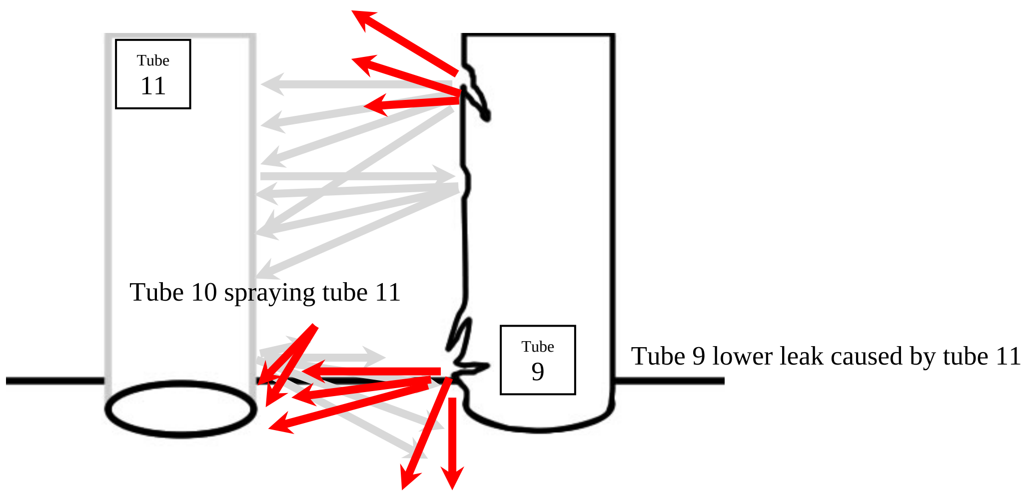
3. All leaks continue to progress.
    a. Leak from Tube 11 results in a new leak in Tube 9, continues to damage Tube 10



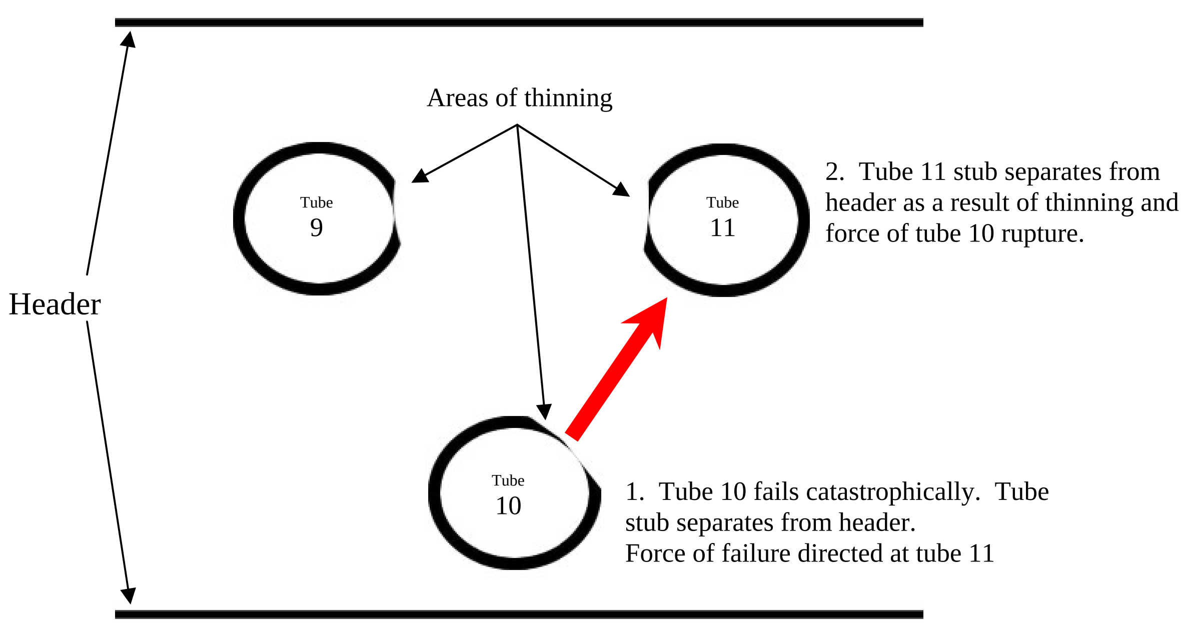
4. All leaks continue to progress and worsen
    a. New leaks from collateral impingement damage develop



5. All leaks continue to progressively worsen over time
   a. Tube 10 is thinned along one plane far below minimum wall thickness
   b. Tube 11 is also thinned considerably below minimum wall thickness
   c. Tube 10 fails catastrophically forcing steam/hot water in the direction of Tube 11
   d. The lateral force applied by the failure of Tube 10 toward the weakened Tube 11 causes Tube 11 to separate from the header.



6. View of tube arrangement on header looking down.
   a. As stated in (5) above, the lateral force applied by the failure of Tube 10 toward Tube 11 caused the already weakened Tube 11 to separate from the header.



Part RB-2020 of the NBIC describes what owners or users should do to prepare a boiler for an internal inspection. Paragraph 3 of this section (See appendix 12) states "[m]anhole and handhole plates, wash out plugs, as well as inspection plugs in water column connections shall be removed as required by the inspector. The boiler shall be cooled and thoroughly cleaned." Part RB-3120 (b) (See appendix 13) lists parts that should be removed as required to permit inspection. This section repeats that manhole and handhole plates are components that should be opened. It also repeats in (c) that "the boiler shall be cooled and thoroughly cleaned." The manhole plate to access the dead air space was not opened and therefore the space was not cleaned.

Part RB-2030 of the NBIC (See appendix 14) states that "[i]f a vessel has not been properly prepared for an internal inspection, the inspector shall decline to make the inspection." Despite of the lower dead air space not being opened or cleaned out, Maule failed to decline to make the inspection and issued a certificate of inspection.

Part RB-3133 of the NBIC (See appendix 13) describes types of defects. It states "[d]efects may include bulged or blistered plates, cracks or other defects in welds or heat-affected zones, pinhole leaks, improper or adequate safety devices, *wasted or eroded material*." (Emphasis added) An inspection of the lower dead air space, in accordance with the code, would have revealed wasted material as a result of corrosive effect of the ash.

Part RB-3158 of the NBIC (See appendix 15) is part of the in-service inspection section of the code. This particular section is dedicated to corrosion. Paragraph J states "[t]he surfaces of tubes should be carefully examined to detect corrosion, erosion, bulges, cracks, or evidence of defective welds … A leak from a tube frequently causes serious corrosion or erosion on adjacent tubes." Paragraph K of this section (See appendix 16) also states "[i]n restricted fireside spaces such as where short tubes or nipples are used to join drums or headers, there is a tendency for fuel and ash to lodge at junction points. Such deposits are likely to cause corrosion if moisture is present and the area should be thoroughly cleaned and examined." Maule's and Dulong's failure to inspect or have the tubes inspected violated these sections of the code.

Finally, Part RB-3280 of the NBIC (See appendix 17) states the following: "[a]ny defect or deficiency in the condition, operating and maintenance practices of the pressure vessel should be discussed with the owner or user at the time of inspection and, if necessary, recommendations made for the correction of such defect or deficiency." Based on the above, it is apparent that the active corrosion in the lower dead air space was something that should not have been overlooked and at a minimum should have required periodic monitoring.

Massachusetts commissioned boiler inspectors, such as Maule, must also hold a National Board Commission. The National Board requires commissioned inspectors to receive continuing education courses each year to ensure they are familiar with the current NBIC. The NBIC code has the following applicable changes since the 1999 version:

- Part RB-1010 "…[u]nderstanding the potential damage/deterioration mechanisms that can affect the mechanical integrity of a pressure retaining item and knowledge of the inspection methods that can be used to find these damage mechanisms are essential to an effective inspection." (See appendix 19)

- Part RB-2000: “Visual examination is the basic method used when conducting an in-service inspection of pressure retaining items. Additional examination and test methods may be required at the discretion of the inspector to provide additional information to assess the condition of the pressure retaining item.” (See appendix 19)

- Part RB-5525: “The refractory supports and settings should be carefully examined, especially at points where the boiler structure comes near the setting walls or floor, to ensure that deposits of ash or soot will not bind the boiler and produce excessive strains on the structure due to the restriction of movement of the parts under operating conditions.” (See appendix 20)

- Part RB 5525: “Drums and headers should be inspected internally and externally for signs of leakage, corrosion, overheating, and erosion.

- Part RB 5601: “There are many locations both internal and external where moisture and oxygen combine causing primary concern for corrosion …Unique parts associated with this type of construction such as casing, expansion supports, superheater, economizer, soot blowers, drums, headers, and tubes should be inspected carefully and thoroughly.” (See appendix 21)

Despite these specific references in the NBIC, Maule failed to enter the dead air space and inspect the components contained within it.

Further, RC-2030 of the NBIC states that “Repairs to pressure retaining items shall not be initiated without the authorization of the Inspector, who shall determine that the repair methods are acceptable.” Based on statements by both Dulong and Brusgalis it was determined that the plant did not always receive proper authorization in accordance with this section.

CONCLUSIONS

Based on the investigation, the DPS has concluded that the following are the **primary causes** of the failure:

1. Division wall tube #9 was identified with a significant through wall weld defect at the tube to stub weld. Internal corrosion or corrosion fatigue propagated the defect to a leak. Although tube stub #11 has yet to be found, it is evident that tube #11, as well as tube #10 sustained substantial collateral damage from steam/water impingement. The collateral damage to tube #10 resulted in a catastrophic failure of tube #10. The force of the failure of tube #10 and the thinned condition of tube #11 (from steam/water impingement) caused the stub of tube #11 to separate from the tube and header. The failure allowed high pressure steam and water to pressurize the dead air space until the boiler casing in that area failed. This sent steam, water and ash, at approximately 600°F, into the immediate area below the boiler.

2. Although the point of initial leak washed the metal away at the leak, as stated in the metallurgical report, the entire header and tubes suffered from external corrosion. It was determined that the external corrosion decreased the tube thickness. This reduction, combined with the weld defect, caused the tube to be in a condition that resulted in the failure. Annual inspection of this space would have significantly abated the degree of corrosion in the space and observation of the current level of corrosion should have prompted further examination.

Based on this investigation, the DPS has identified the following **contributing factors**:

1. **A Failure to inspect and maintain the Dead Air Spaces.** Massachusetts regulation 522 CMR 2.02 places the responsibility of the operation and maintenance of steam boilers under the Engineer-in-charge. Not a single witness, including the Engineer-in-charge Dulong, could indicate when the dead air space had been opened for inspection or maintenance since at least 1998 or 1999. The National Board Inspection Code specifically highlights areas of concern that must be inspected, including tubes and headers that may be exposed to, or covered with ash. Proper maintenance and inspection of this area would have minimized the potential for external corrosion.

2. **Failure of the Insurance Inspector to Inspect the Dead Air Space Annually.** Massachusetts General Law Chapter 146 section 25 requires steam boilers to be inspected in accordance with the rules of the Board of Boiler Rules. Massachusetts regulations 522 CMR 15.00 adopts the National Board Inspection Code. The boiler was not inspected in accordance with the National Board Inspection Code which requires "Drums and headers should be inspected internally and externally for signs of leakage, corrosion, overheating, and erosion. (Part RB 5525).

3. **Improper Delegation of Responsibilities to Unlicensed Personnel.** During the interview process it was clear that the Engineer-in-charge improperly delegated his responsibilities to unlicensed individuals. This overall delegation of Dulong's responsibilities as the Engineer-in-charge to others resulted in a systematic breakdown in which no one assumed responsibility for ensuring compliance with statutory and regulatory requirements. Such improper delegation included:
    a. Reliance on unlicensed individuals to oversee boiler repairs and allowing these unlicensed persons to make decisions regarding the extent of the repairs and the

non-destructive testing. Dulong relied on the Quality Control person (Brusgalis) and others to evaluate other areas in the boiler to determine if the potential for additional problems existed. Brusgalis, however, stated that these decisions were in fact made by the mechanical maintenance group. Further, Dulong stated that he relies on others to ensure repairs are performed in accordance with the Code. These responsibilities rest with the Engineer-in-charge who is presumed to have the requisite knowledge and experience to make such determinations. Following the January 2007 tube repair, Dulong failed to properly investigate whether any further action was necessary or was appropriate. Had the space been opened and properly maintained, the extensive corrosion would have been noticed and a properly licensed person should have determined that further testing was appropriate.

b. Reliance on others to ensure that Authorized Inspectors were contacted before boiler repairs were initiated in accordance with the NBIC. During the interview process, Brusgalis admitted that repairs to the boilers were initiated and/or completed prior to contacting the Authorized Inspector and Dulong did not appear to understand that the Code required an Authorized Inspector to be contacted prior to making repairs. Further both Dulong and Brusgalis stated that the plant, and not the Authorized Inspector, determined whether a hydrostatic test should be performed following a repair, in violation of the NBIC.

c. Reliance on others to ensure that the boiler was pressure tested per the direction of the Authorized Inspector following a repair. The procedures followed by the plant in performing boiler repairs failed to comply with the National Board Inspection Code and the plant failed to properly pressure test Boiler #3 following the last boiler repair in September 2007.

4. **Failure to Implement The Boiler Condition Assessment and Life Extension Program.** It is the responsibility of the Engineer-in-charge to have knowledge of, or perform boiler condition assessment and life extension studies, when recommended by the boiler manufacturer or industry standards. Although plant personnel believed a life extension program had been done on the plant in the 1980's, it was evident from interviews that the plant personnel did not know exactly what that plan required, and Dulong was not even aware if one existed. As stated earlier, Babcock & Wilcox issued a document "Standard Recommendations for Pressure Part Inspection During a Boiler Life Extension Program" in May 2000. Since the space had not been opened since the issuance of this document from the manufacturer, it is clear that the facility failed to follow these recommendations.

5. **Improper Recognition of Existing Plant Hazards.** Despite repeated common boiler failures, the plant personnel had an unacceptable tolerance of boiler tube failures and did not have a policy in place to examine other areas of potential concern for similar failures at the time of a failure. Additionally, the plant did not have a policy or procedure in place to educate or warn employees of failure mechanisms or how to identify them.

6. **Improper Boiler Maintenance Practices.** It has been the plant's routine practices for personnel to water wash the boiler furnace during a plant outage. This water was allowed to enter the lower dead air spaces, which was full of ash, causing corrosion. There was no effort taken to routinely remove this corrosive ash mixture from those spaces.

7. **Improper Plant Personnel Operating Practice** It was a common plant practice to accelerate boiler cooling following a boiler failure by fan cooling the boiler, resulting in exceeding the manufacturers recommended boiler cool down parameters. This exacerbated cyclic stresses on boiler components.

8. **Failure of boiler operators to identify the leak prior to catastrophic failure.** A review of the boiler control system (DCS) trends demonstrated that the early indications of a tube leak were becoming apparent, but were not identified by operating personnel.

PHOTO LOG

Location: Salem Harbor Generating Station Date: 11/06/2007

Investigating Inspector(s): Mark F. Mooney / Edward Kawa

Photo Number	Description
1	Salem Harbor Generating Station
2	Boiler 3 division wall header (facing north)
3	Boiler 3 division wall header (facing south)
4	Dead air space showing casing failure
5	Dead air space showing ruptured boiler casing
6	Work space immediately below point of failure
7	Area adjacent to point of area below failure
8	Area immediately below casing failure
9	Division wall header
10	Division wall header
11	Close up of tube 9 and header
12	Close up of tube 9 and header
13	Close up of header at tube 10 & 11
14	Close up of header at tube 9 & 11
15	Steam impingement indications between tube 9 & 11
16	Overview of header after being removed
17	Overview of header at failure area
18	Close up of header at tube 10 & 11
19	Overview of header at point of failures
20	Close up of tube 9
21	Close up of tube 9 top leak
22	Close up of tube 9 top leaks
23	Corrosion photos of tubes and header
24	Corrosion photos of tubes and header
25	Corrosion photos of tubes and header
26	Corrosion photos of tubes and header
27	Corrosion photos of tubes and header
28	Overview of header at point of failure
29	Close up of header damage from steam / water impingement
30	Close up of tube 10 showing poor weld

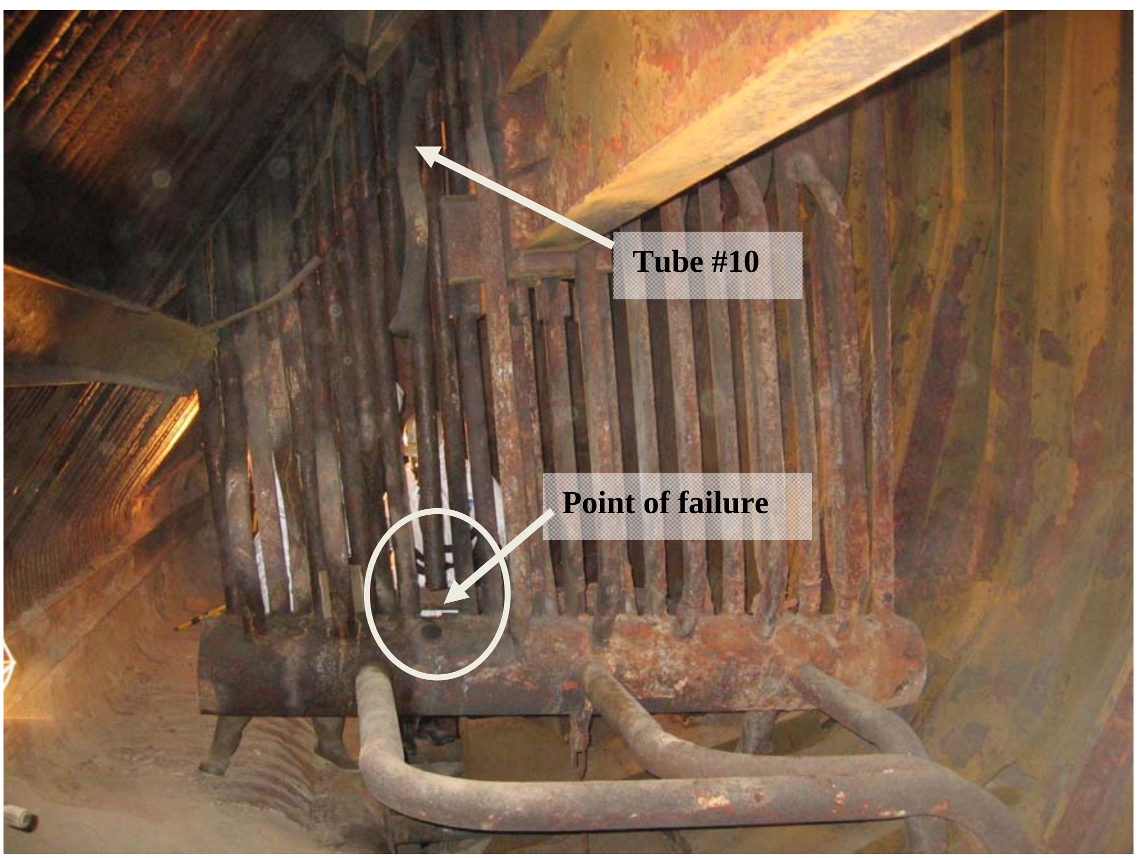
PHOTO LOG

Location: Salem Harbor Generating Station Date: 11/06/2007

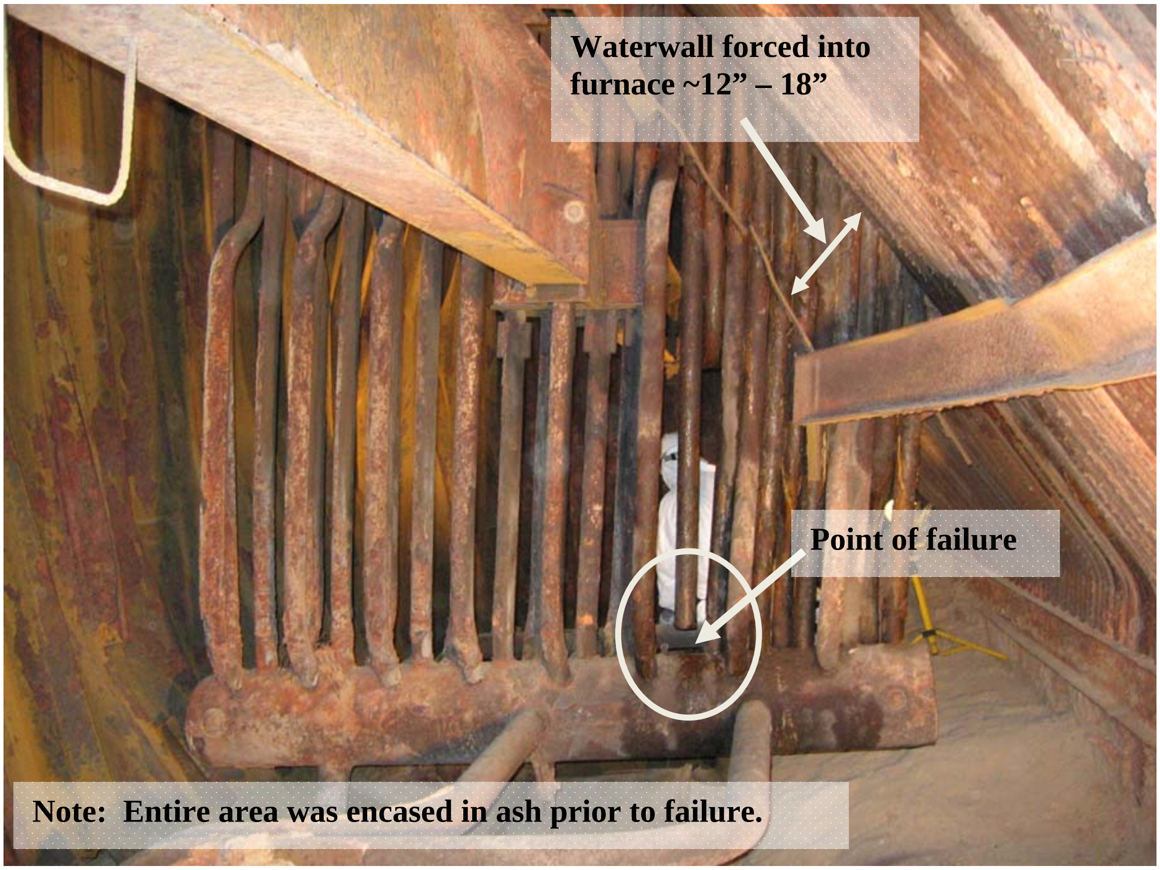
Investigating Inspector(s): Mark F. Mooney / Edward Kawa

Photo Number	Description
31	Close up of tube 10 showing poor weld
32	Tube 10
33	Tube 10 showing damage from steam water impingement
34	Close up of tube 11
35	Close up of tube 10
36	Internal view of tube 9
37	View of header after cleaning
38	Cut away of tube 10 stub
39	Boiler #3 data plate
40	Boiler #3 data plate
41	Close up of tube 9 middle leak
42	West side dead air space before ash is completely removed
43	West side dead air space
44	West side dead air space
45	West side dead air space
46	West side dead air space ash
47	West side dead air space ash
48	West side dead air space tubes impacted with ash
49	West side dead air space after ash is removed
50	West side dead air space after ash is removed
51	West side dead air space after ash is removed – tube closeup
52	West side dead air space after ash is removed – header view

1. Salem Harbor Generating Station
Dominion Energy New England



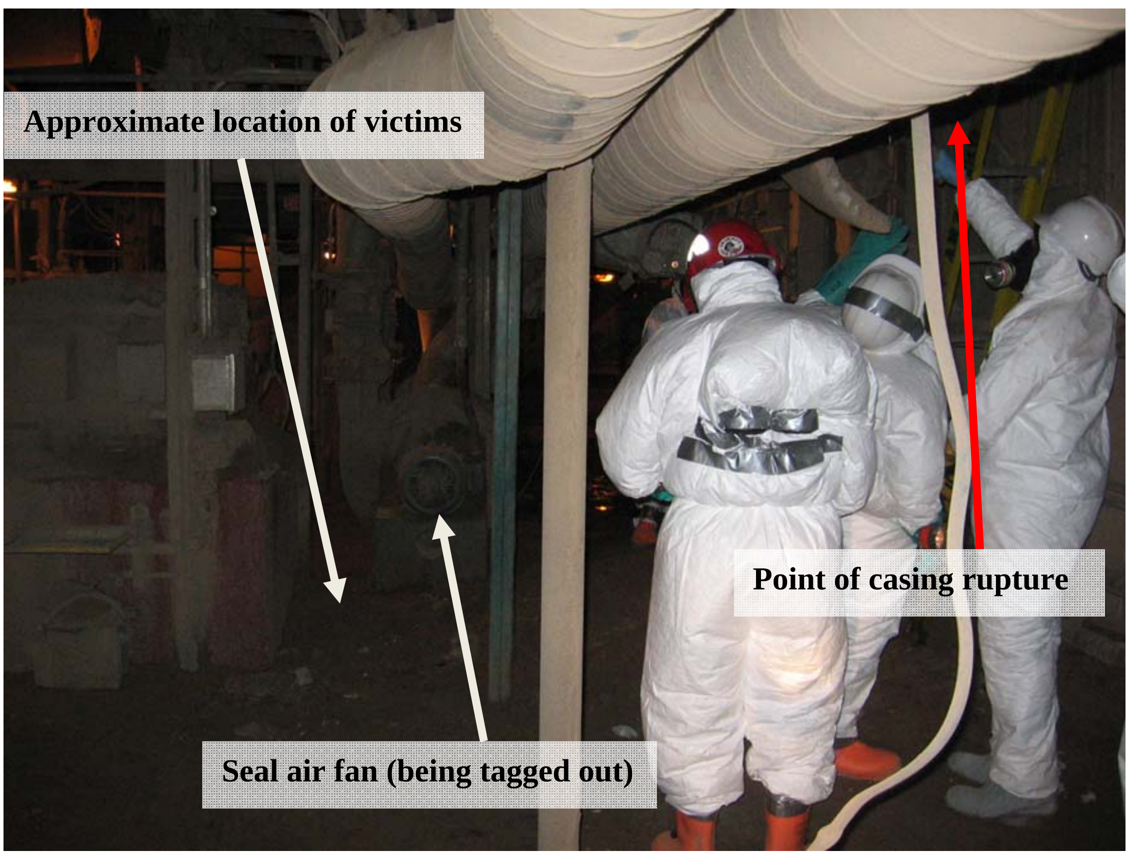
2. Boiler #3 Division Wall Header (facing north)



3. Boiler #3 Division Wall Header (facing south)

4. Dead air space showing ruptured boiler casing (facing south)

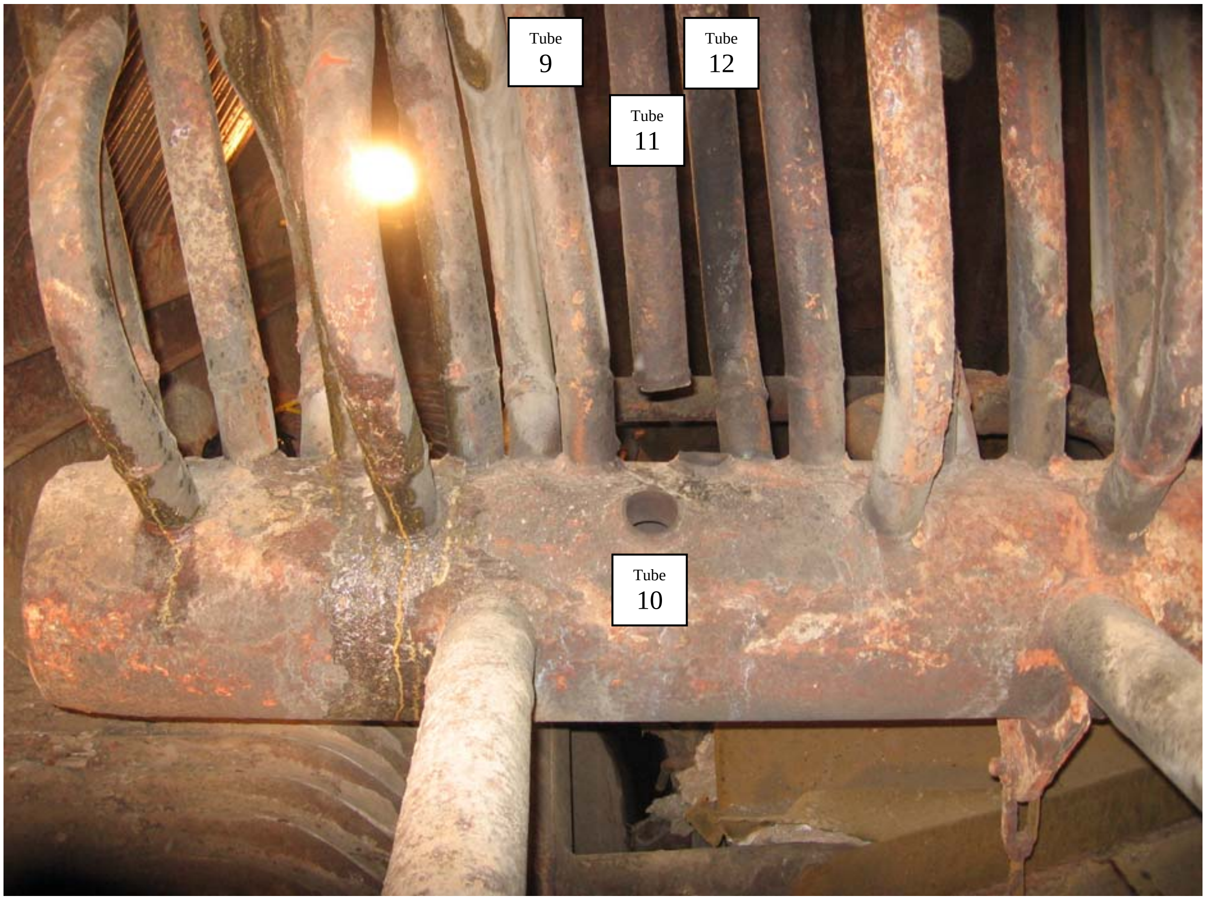
5. Dead air space showing ruptured boiler casing (looking down, facing south)



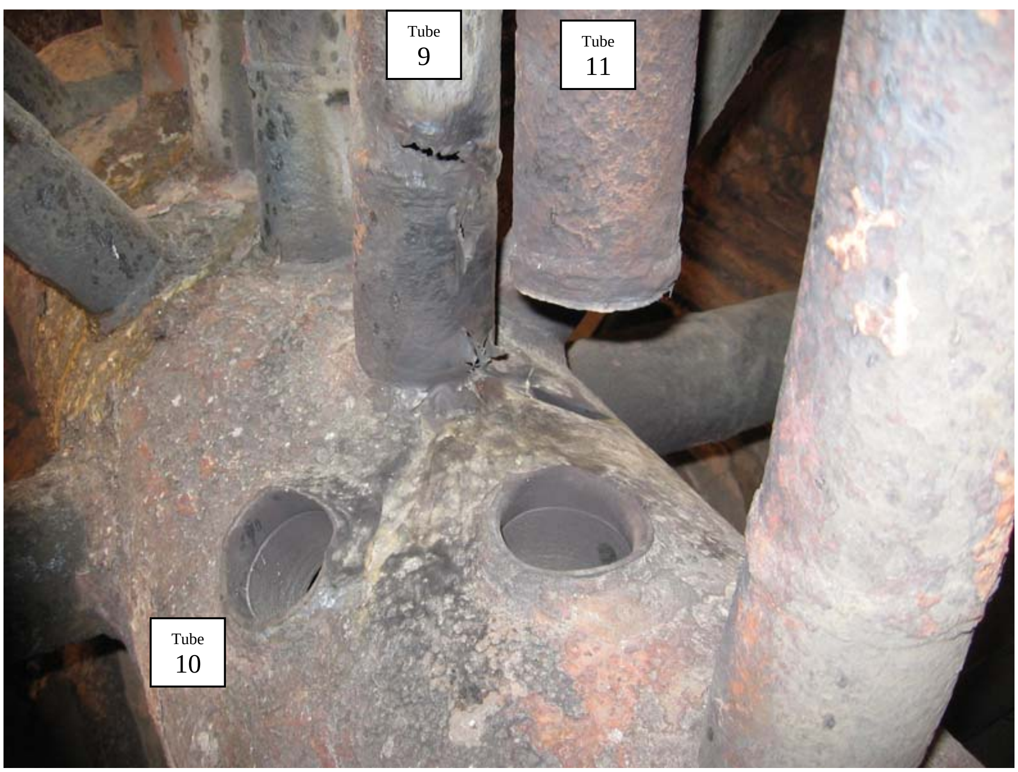
6. Work space immediately below point of failure (facing north)

7. **Area adjacent to point area below failure (facing south)**

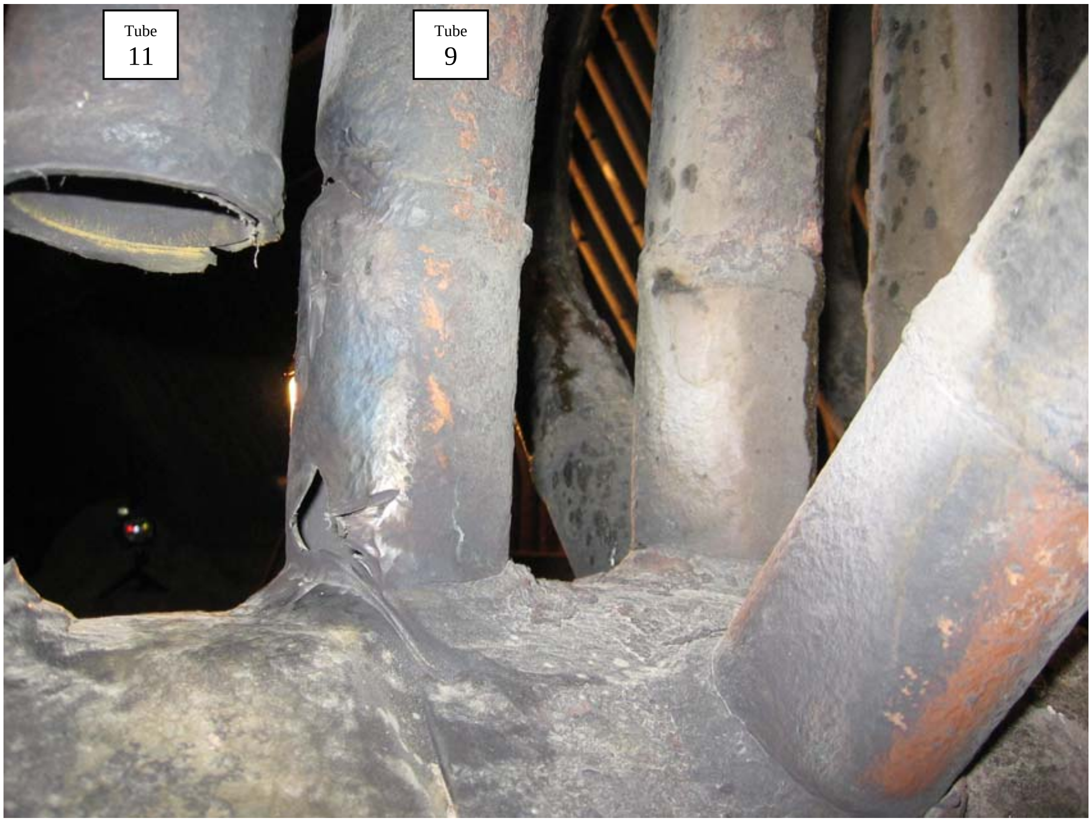
8. **Area immediately below casing failure (facing south)**



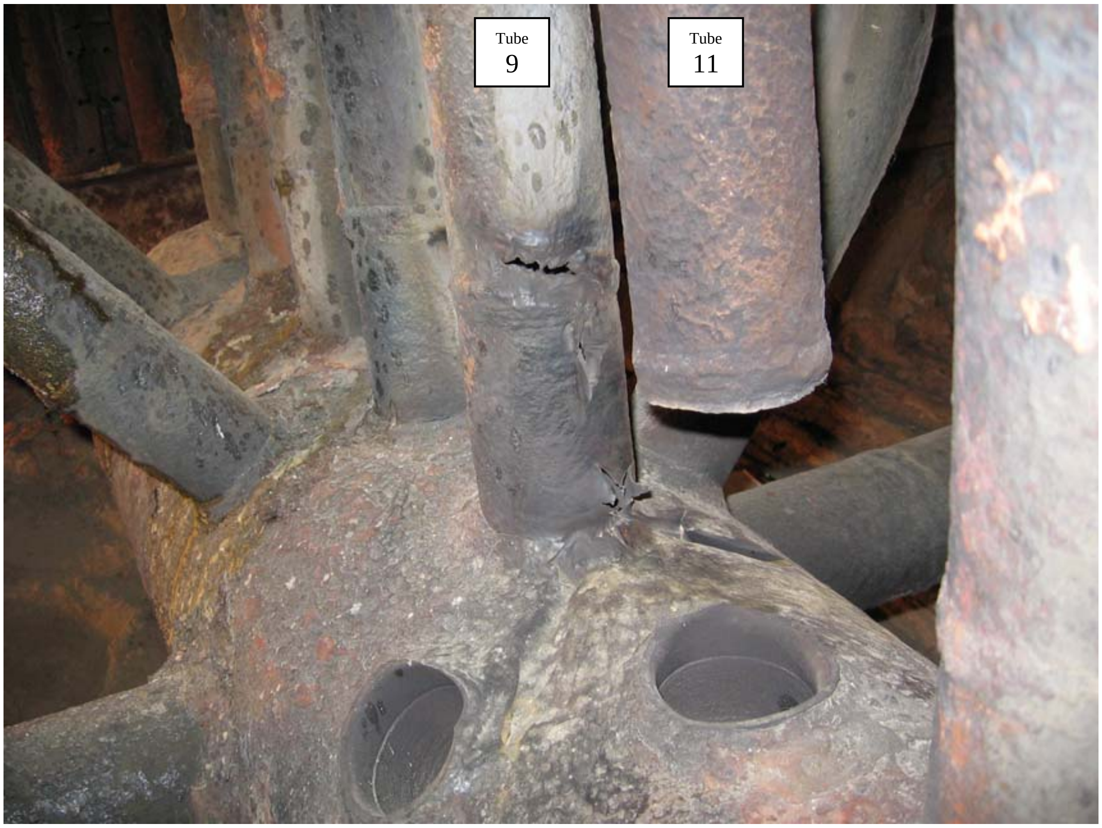
9. Division Wall Header



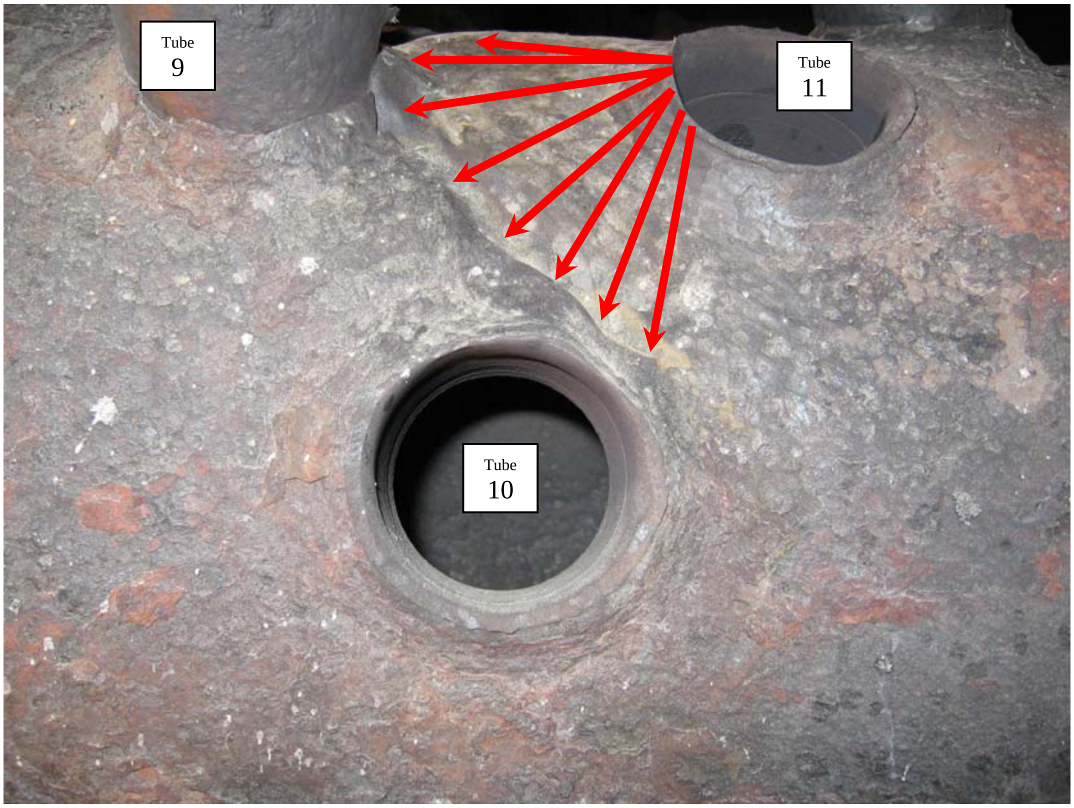
10. Division Wall Header.



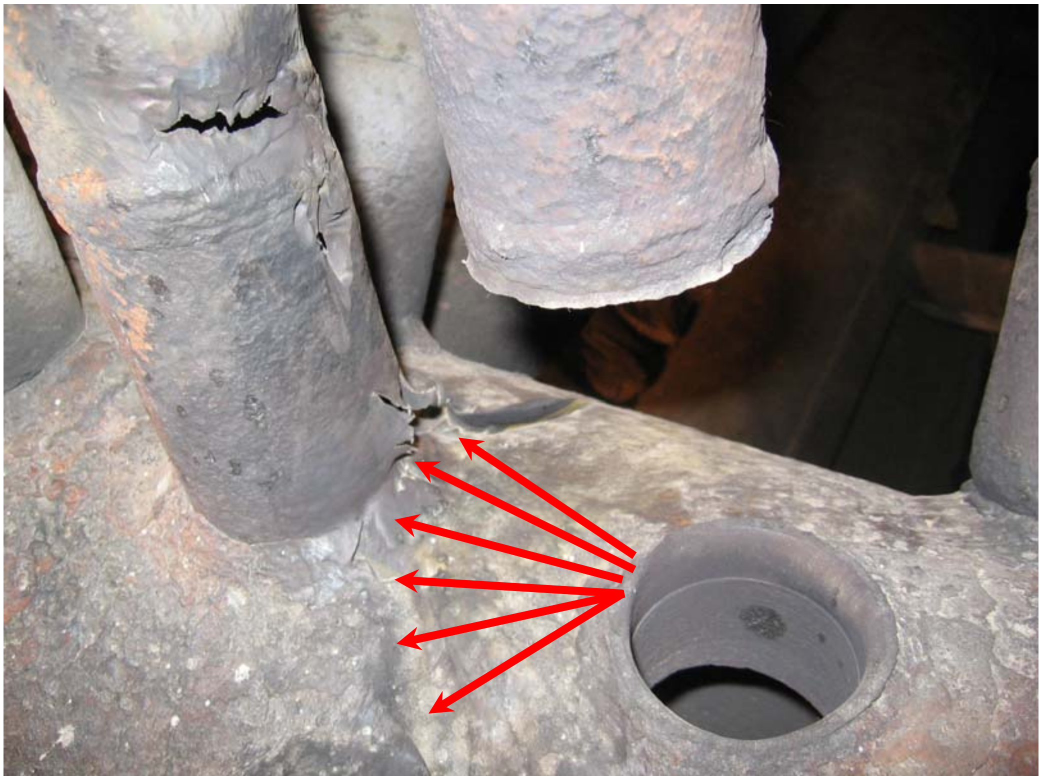
11. Close up of tube 9 and header



12. Close-up of tube 9 and header

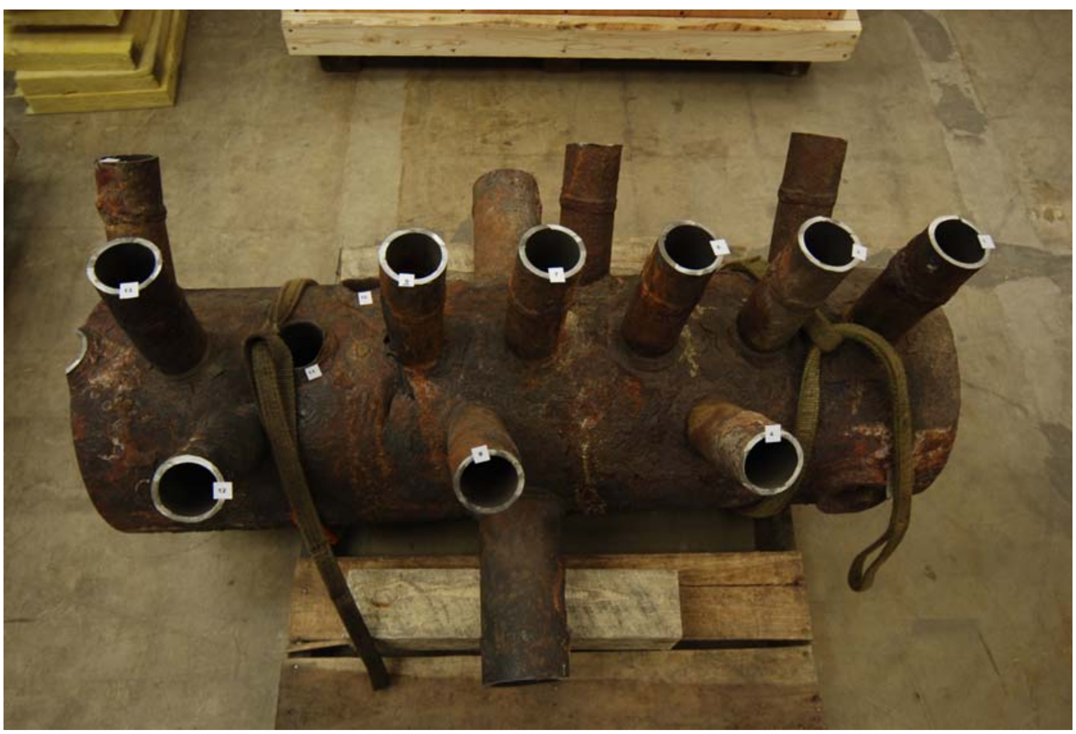


13. Close-up of header at tube 10 and 11



14. Close-up of header at tube 9 and 11

15. Steam impingement indications between tube 9 and 11



16. Overview of header after being removed

17. Overview of header at failure area

18. Close-up of header at tube 10 and 11

19. Overview of header at point of failures

20. Close-up of tube 9

21. Close-up of tube 9 top leak

22. Close-up of tube 9 top leaks

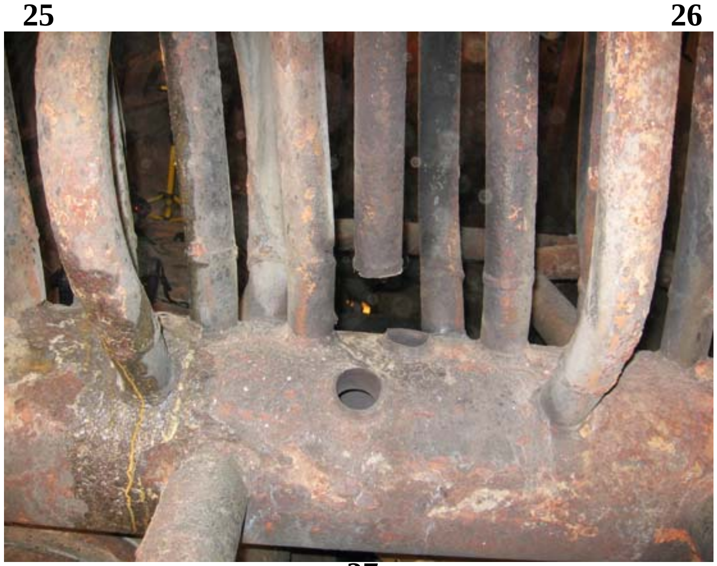
Tube and Header Corrosion Photos (23 – 27)

23

24

25

26



27

28. Overview of header at point of failure

29. Close-up of header damage from steam/water impingement

30. Close-up of Tube 10 showing poor weld

31. Close-up of Tube 10 showing poor weld

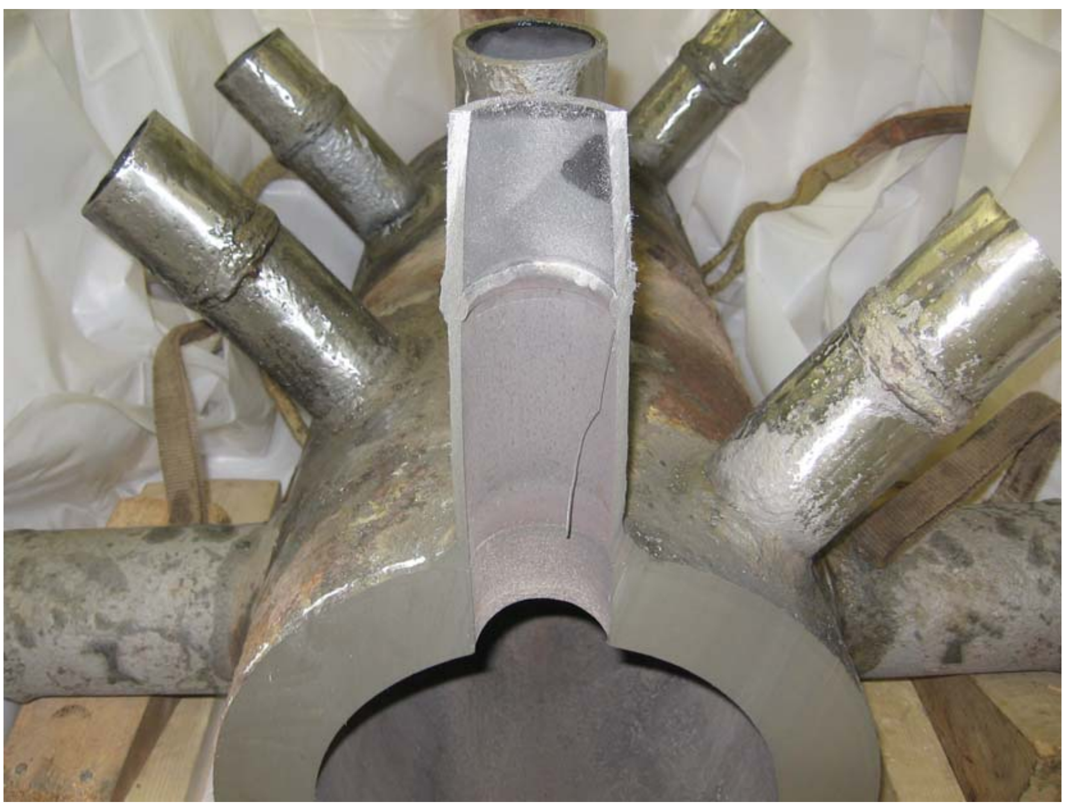
32. Tube 10

33. Tube 10 showing damage from steam / water impingement

34. Close-up of Tube 11

35. Close-up of Tube 10

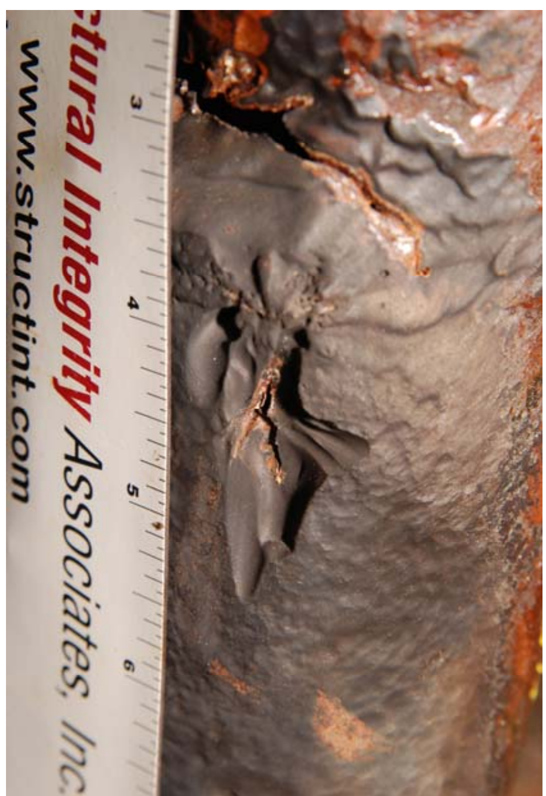

36. Internal view of Tube 9


37. View of header after cleaning

38. Cut away of Tube 10 stub (with bad weld)

39. Boiler Dataplate

40. Boiler Dataplate



41. Close-up of Tube 9 middle leak


42. West side dead air space before ash is completely removed


43. West side dead air space before ash is completely removed
Tubes encased in ash going to lower header

44. West side dead air space. Ash on top of header

45. West side dead air space before ash is completely removed
Note level of ash behind tubes.

46. West side dead air space before ash is completely removed

47. West side dead air space before ash is completely removed

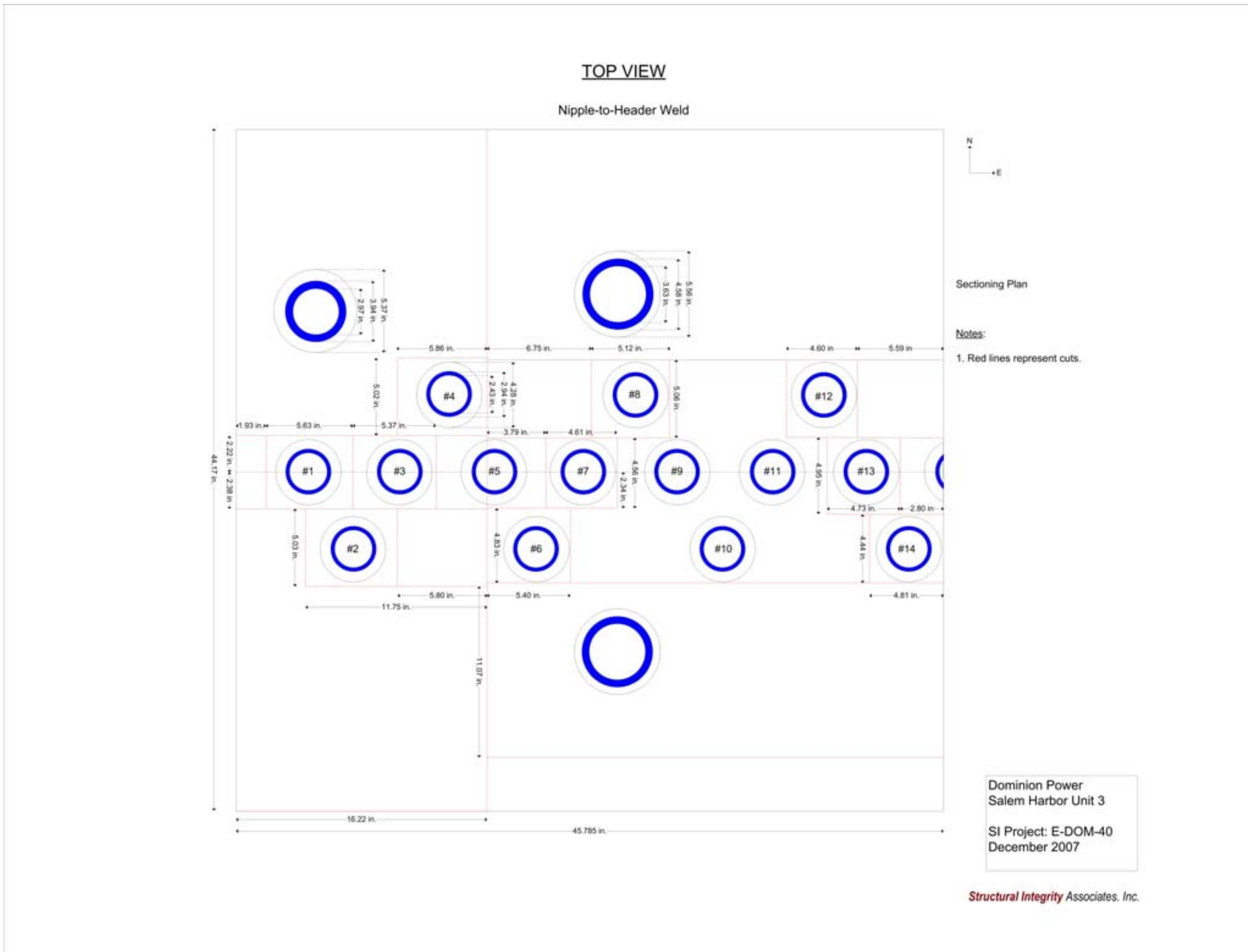
48. West side dead air space before ash is completely removed
Note impacted ash between tubes above header (buried)

49. West side dead air space after ash is removed.
Prior level of ash is evident on division wall header

**50. West side dead air space after ash is removed.
Prior level of ash is evident on division wall header**

51. West side dead air space header after ash is initially vacuumed out

52. West side dead air space after ash is initially vacuumed out. Difference in corrosion in tubes closest to header



Boiler #3 Drawing / Layout

AIG Inspection Report – Page 1

AIG Global Marine and Energy

175 Water Street, 29th Floor, New York, NY 10038

Dominion Resources, Inc.
Dominion Energy Salem Harbor
24 Fort Avenue
Salem, MA 01970

JURISDICTIONAL INSPECTION REPORT
April 10, 2007

A00047

AIG Inspection Report – Page 2

AIG Global Marine and Energy
175 Water Street, 29th Floor, New York, NY 10038

RFS No.: 25182
Service Date: April 10, 2007
Technical Risks Consultant: R. Maule, AIG Global Marine and Energy
Conferred With: Steven Dulong, Manager F&H Operations and Maintenance, Operations

LOCATION OVERVIEW

The Salem Harbor Station is a 680 mW fossil-fired generating facility located on a 65-acre waterfront site in Salem, Massachusetts. Salem Harbor Station, which began commercial operations in 1951, consists of three units that are capable of burning coal and oil and a fourth unit, which burns only fuel oil. Deliveries of coal and fuel oil are currently made to the deepwater port located at this facility. Additionally the facility is located within the Boston/Northeast Massachusetts load pocket.

The number 1 and 2 boilers are each balanced draft units capable of producing 625,000-lbs/hr steam and were manufactured by Babcock and Wilcox. The boilers are fired on pulverized coal or oil and natural gas is used for light-off purposes. The steam from the boilers is used as motive steam in General Electric (unit 1) and Westinghouse (unit 2) tandem, double flow, reheat steam turbines that are each rated at 60 mW. The generators are each rated at 75 MVA and 14,400 volts.

Babcock & Wilcox manufactured the unit 3 boiler, which is a balanced draft unit capable of generating 1,000,000 lbs/hr steam at 2,225 psi and 1,000° F. The boiler is fired on pulverized coal or oil and natural gas is used for light-off purposes. The steam is directed to a General Electric tandem, double flow, reheat turbine that can produce 125 mW. The General Electric generator is rated at 154 MVA and 14,400 volts.

The number 4 boiler is a pressurized furnace unit capable of generating 3,250,000 lbs/hr steam and was manufactured by Riley Stoker. The boiler burns number 6 oil, natural gas or a combination of the two. The boiler provides motive steam to the General Electric three casing, quadruple flow, reheat steam turbine that is rated at 436 mW. The General Electric generator has a rating of 528 MVA and 22,000 volts. Unit 4 was initially constructed as a peak shaving unit (typically these type machines have larger clearances to allow it to be brought on line faster). However, in response to the current demands of the grid, in recent years the steam turbine has been modified to make it more efficient (closer clearances).

A00048

AIG Inspection Report – Page 3

AIG Global Marine and Energy
175 Water Street, 29th Floor, New York, NY 10038

Dominion Resources, Inc.
Dominion Energy Salem Harbor
April 10, 2007
Page 3

SUMMARY OF INSPECTION ACTIVITY

AIG Global Marine and Energy conducted an internal and external examination on the Dominion Energy Salem Harbor unit 3 boiler on the above date to satisfy jurisdictional and loss prevention requirements. Our inspection was completed in conjunction with a scheduled major disassembled inspection of the steam turbine generator associated with this boiler. As for the boiler itself, the critical path repair item was the replacement of the blistered water wall tubes on the west (rear) wall of the furnace. We will provide further details on this activity later in this report. Additionally, a chemical cleaning of the watersides has been scheduled prior to returning the unit to service. It was reported that this boiler, which is operated as a base loaded unit, has performed satisfactorily since our last inspection. The nameplate information for the boiler is as follows:

Babcock and Wilcox water tube boiler unit 3, NB19517, 2,225 psi MAWP, 1,000,000 pounds of steam per hour, 1,000° superheater and reheat, 40,603-ft2 waterwall surface, built in 1957.

Dennis Nygaard, Alstom Power field service engineer, has been on site during the outage completing his internal and external inspection of this boiler. Mr. Nygaard is brought on site annually to inspect each of the boilers during their respective outages. Also, Warren Taylor and Frank Timmons, both engineers with the Dominion Fossil and Hydro Technical Services group were on site to provide technical support for the boiler outage activities.

Our inspection was completed in accordance with the Commonwealth of Massachusetts Statutes and Regulations, the National Board Inspection Code (NBIC) and the National Union Fire Insurance Company Quality Program. The inspection process consisted of a visual inspection of the accessible waterside, gas side, instrumentation and controls, and the external areas of the boiler. During our inspection we found the unit in satisfactory condition with no Code violations identified. The Commonwealth of Massachusetts was notified and a Certificate of Operation will be issued allowing the plant to operate the boiler for an additional year. All of our observations and conditions requiring attention were discussed with Mr. Dulong, Manager, F&H Operations and Maintenance, Operations.

There were no open jurisdictional recommendations from previous boiler inspections and as a result of the inspection completed on this date no new recommendations were issued.

A00049

AIG Inspection Report – Page 4

JURISDICTIONAL DISCUSSION

Welded Repairs and/or Alterations
The plant has completed repairs to various pressure retaining components during the past year. These repairs are typically on tubes that had failed while the boiler was in operation and the exact number and extent of these repairs was not available at the time of our inspection. We asked Mr. Dulong to forward the R-1 Reports for the welded repairs that were completed during the past certificate period for our review.

Steam Drum
The steam drum was entered and found to be in very good condition. The internal surfaces of the drum had a uniform layer of magnetite that was evenly distributed throughout the drum. The longitudinal, circumferential and attachment welds were visually inspected and found free of surface indications. The drum nozzle penetrations to the various boiler monitoring equipment were examined and found clear from obstructions. All of the moisture separating and component supports were properly installed and free of distortion.

The only area of concern we noticed in the steam drum was several loose dogs that are used to securer the various baffle plates in the drum. The loose dogs were found near the center of the drum and are the ones that are used to secure the fifth and sixth lower plates when counting from the north end of the drum. These should be retightened prior to returning the unit to service.

The water treatment is accomplished with a dual train separate bed demineralizer type system that has automatic regenerating capability. Each train has the capacity to treat 100% of the demineralized water requirements for unit 3. The system uses a high concentration of sulfuric acid and sodium hydroxide for regeneration purposes. The regeneration effluent is discharged to a neutralizing tank prior to being released to the waste water system. Based on our observations of the internal portions of the steam drum, the water treatment program is considered to be very good.

Gas Sides
As we reported in our report for the August 29, 2006 inspection of this boiler, the unit was suffering an inordinate number of waterwall tube failures. The plant found that the failed tubes each had gas side blisters and their investigation into the cause revealed that one of the coal pulverizers (mills) was not reducing load as directed by the boiler master. During the 2006 outage each tube in the affected area was given a close visual inspection by the plant staff and all of the blistered areas were identified (no non-destructive examination techniques were employed). At that time the plant elected to repair the blistered area with the installation of Dutchmen, window patches, or by building the blistered area up with weld metal. The method of repair depended on the severity of the damage in the blistered area and the location of the affected tube.

AIG Inspection Report – Page 5

In this boiler the secondary superheater assemblies are exposed to the luminous furnace radiation and to assure that the gasses do not bypass these assemblies, the rear waterwall tubes are bent into a triangular shape (typically referred to as a bullnose) to help direct the gasses toward the superheater. Nearly all of the blisters were found in the bull nose area of the rear wall. For this outage each of the tubes that form the bullnose will be replaced from a point just above and below the bullnose.

Our inspection of the final pass of several of the welds for the tube replacement described above found them free of undercut, porosity, and slag inclusion. In each weld we inspected it appeared as if the weld metal had been thoroughly incorporated into the base steel of the tube.

In our discussion of the repair with Mr. Taylor and Mr. Timmons they indicated that they would have preferred it if the contractor had removed more of the past tube repair field welds as part of the tube replacement. In their opinion, should any of the existing repair welds have projections into the tube inside diameter (blow through during the welding of the root pass); these could adversely affect the laminar flow of water through the tubes. By extending the length of the tube replacement several prior field welds could have been removed and help eliminate future waterside flow problems.

The secondary superheater tubes were free of excessive warpage due to overheat, however, several of the steel bands that are used to keep the secondary assemblies aligned had broken. The bands will be repaired/replaced during this outage. Mr. Timmons stated that there are plans to replace this superheater during the 2008 outage for this boiler.

Various access doors were entered to inspect the condition of the tube firesides and the boiler refractory in the remaining sections of the boiler. The reheater assemblies were found with most of the accessible aligning clips properly engaged and any that had deteriorated during the past year were being replaced. We noticed that several of the reheat assemblies had "paired-off" (two assemblies have moved so that they are in partial contact with each other) forming gas lanes. As with most fluids in motion, the combustion gasses will take the path of least resistance and as such the lanes offer an easier path for the gasses to pass through the reheater. These gas lanes can be areas of higher than normal fireside erosion due to the accelerated gas flow and the by products of burning coal. According to Mr. Nygaard the plant has not encountered any trouble maintaining the proper reheat temperature. We will monitor this area for fireside erosion during our future inspections.

The majority of the refractory used to seal the gas passes and around the openings in the upper portions of the boiler were inspected and there were no indications of spalling, excessive cracking or areas of missing refractory material found.

The economizer was inspected from the access doors and we did not notice any areas of concern.

AIG Inspection Report – Page 6

AIG Global Marine and Energy
175 Water Street, 29th Floor, New York, NY 10038

Dominion Resources, Inc.
Dominion Energy Salem Harbor
April 10, 2007
Page 6

Safety Valves
The nameplate information for the safety valves on the boilers is as follows:

Valve	Manufacturer	Set Pressure, psi	Capacity, lbs/hr	Test Date
Steam Drum	Consolidated	2,220	276,113	See below
Steam Drum	Consolidated	2,200	107,450	See below
Steam Drum	Consolidated	2,225	275,214	See below
Steam Drum	Consolidated	2,225	275,214	See below
Superheater	Consolidated	2,125	112,415	See below
Superheater	Consolidated	2,130	112,730	See below
Cold Reheat	Consolidated	650	279,950	See below
Cold Reheat	Consolidated	640	266,900	See below
Cold Reheat	Consolidated	690	64,645	See below
Cold Reheat	Consolidated	630	262,770	See below
Hot Reheat	Consolidated	615	88,450	See below
Hot Reheat	Consolidated	605	87,002	See below

In addition to the jurisdictionally required annual lift test (an EVT lift test is conducted by Chalmers and Kubeck at this facility), each of the above valves is overhauled annually.

External Surfaces
Externally, the boiler was found in good condition and well maintained. The boiler casings are free from any visible signs of overheating or bowing. The pipe hangers and component supports were examined and found to be adequately supporting their static and dynamic loads.

The pressure and temperature gages, level indicators, and the various trip devices for the boiler looked to be in good working order and well maintained. Mr. Dulong reported that the low water cut out for the steam drum is tested on an annual basis by blowing down the water columns for the drum. The digital Yarway level indicators are tested daily with a simulated test. The various trip devices and their associated alarms are tested yearly. Additionally, the pressure gage for the boiler is calibrated annually with the work to be completed during the current outage.

We would like to express our appreciation for the courtesy and cooperation extended us by Mr. Dulong during our inspection. Should you have any questions or comments on this process please contact Bob Maule at 207-834-3767.

A00052

AIG Inspection Report – Page 7

AIG Global Marine and Energy
175 Water Street, 29th Floor, New York, NY 10038

Dominion Resources, Inc.
Dominion Energy Salem Harbor
April 10, 2007
Page 7

This report has been distributed to:

Ms. Linda Barnett
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A00053

FORM NO. P-3 MANUFACTURERS' DATA REPORT FOR WATER-TUBE BOILERS, SUPERHEATERS, WATERWALLS AND ECONOMIZERS

B&W-1 334-0284-10 As Required by the Provisions of the A.S.M.E. Code Rules 1014

1. Manufactured by The Babcock & Wilcox Co. Barberton, Ohio
(Name and address of manufacturer)

2. Manufactured for The New England Power Company Salem, Mass.
(Name and address of purchaser)

3. Identification Radiant Heat Boiler, Bent Tube Boiler No. 19517
(Type of boiler, superheater, waterwall, economizer) (Mfrs. Serial No.)

(State and State No.) Natl. Board No. 19517 Year Built 1957

4. The chemical and physical properties of all parts meet the requirements of material specifications of the A.S.M.E. Boiler Code. The design, construction, and workmanship conform to A.S.M.E. Rules Yes

Remarks: Manufacturers' Partial Data Reports properly identified and signed by Commissioned Inspectors ... the following items of this report:
(Name of Part—Item number, manufacturer's name, and identifying stamp)

See Separate P-3 Data For Reheat Section

RECEIVED
MAY 23 1958
THE NATIONAL BOARD OF BOILER & PRESSURE VESSEL INSPECTORS

We certify the statement in this data report to be correct.

Date February 26, 19 58 Signed The Babcock & Wilcox Co. By R.H. Huston
(Manufacturer) (Representative)

Certificate of Authorization Expires December 31, 19 58

CERTIFICATE OF BOILER SHOP INSPECTION

Insurance Companies' Serial Number HSB-19517

BOILER WORKS OF The Babcock & Wilcox Co. at Barberton, Ohio

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co. of Hartford, Conn., have inspected parts of the boiler referred to as data items (All Tubes, Shop Welds Only) 5a, 6a, 7a, 8a, 9a, 10, 11 and have examined manufacturers' data for items ... and certify that the material, construction, and workmanship are in accordance with A.S.M.E. Boiler Code Rules.

DATE November 18, 19 57 H. M. Lorenz Commissions NB# 2526
Inspector State or Natl. Board and No.

CERTIFICATE OF FIELD ASSEMBLY INSPECTION

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co of Boston, have compared the statement in this manufacturers' data report with the described boiler and certify that parts referred to as data items 5b, 6b, 7b, 8b, 9a, 10, 12, ~~not included in certificate of shop inspection~~ are in accordance with the requirements of the A.S.M.E. Boiler Code. The described boiler was inspected and subjected to a hydrostatic test of 3338 # lb. per sq. in.

DATE 4/18 19 58 N. W. Burns Commissions NB# 2951
Inspector State or Natl. Board and No.

Appendix 2

5(a) Drums

No.	Nominal diameter Inches	Length Ft. In.	Shell Plates Brand	Material Spec. No.	Thickness	Inside Radius	Tube Sheets Thickness	Inside Radius	Tube Hole Ligament Efficiency Longitudinal	Circumferential
1										
2	66"	48' - 7 1/2	F.B.	SA-212 B	5 3/4"	33"	5 3/4"	33"	.8307	.4211
3										
4										

No.	Longitud'l Joints No. & Type*	Effic'cy	Circum. Joints No. & Type	Effic'cy	Heads Brand	Material Spec. No.	Thickness		Type**	Radius of Dish	Manholes No. Size	Hydrostatic Test, lb.
1												
2	2-#2	.95	3-#2	.95	F.B.	SA-212 B	4 3/4"	4 3/4"	#4	33"	2--16"Dia.	
3												
4												

* Indicate if 1. Seamless; 2. Fusion welded; 3. Forge welded; 4. Riveted.

** Indicate if 1. Flat; 2. Dished; 3. Ellipsoidal; 4. Hemispherical.

5(b) Boiler Tubes

Diamet'r	Thickn's	Material Specification No.
2 31/32	.240	SA-210
"	.284	SA-192

5(c) Headers No. .... (Box or sinuous; Mat. Spec. No.; Thickness)

Heads or Ends .... Hydro. Test-Lb. (Shape; Mat. Spec. No.; Thickness)

6(a) Waterwall Headers & Downcomers — 6(b) Waterwall Tubes

No.	Size and Shape	Matl. Spec. No.	Thickness	Heads or Ends Shape	Thickness	Matl. Spec. No.	Hydro. Test, lb.	Diamet'r	Thickn's	Matl. Spec. No.
15	14" O.D.	SA-106 B	1 7/8"	Fig.P21b	1 7/8"	SA-106 B		2 31/32	.240	SA-210
2	24 1/2"I.D.	SA-106 C	1 7/8" &	Hemis	1 1/4"	SA-106 C		2 31/32	.284	SA-192
			3 1/4"					4 1/2	.380	SA-210
2	28 1/4" OD.	SA-106 C	1 7/8"	Open				3"	.650	SA-210
								2 31/32	.250	SA-210

7(a) Economizer Headers — 7(b) Economizer Tubes

1	11 3/4"O.D.	SA-106 B	1 1/2"	Open				2 1/4"	.220	SA-178 A
1	11 3/4"O.D.	SA-106 B	1 1/2"	Fig.P21b	1 5/8	SA-106 B				

8(a) Superheater Headers — 8(b) Superheater Tubes

1	17 3/4"O.D.	SA-335P-11	2 1/2"	Fig.P21b	2 3/4	SA-335P-11		2 31/32	.250	SA-210
5	14" O.D.	SA-106 B	1 7/8"	"	1 7/8	SA-106 B		2 31/32	.280	SA-209T1a
5	11 3/4"O.D.	"	1 7/8"	"	1 7/8	"		5"	.420	SA-210
1	12 5/8"I.D.	SA-335P-11	1 5/16 &	Ellip.	1 3/8	SA-335P-11		4"	.340	"
			2 1/16"					3"	.650	"
1	20 1/2"O.D.	"	2 7/8"	Open				2 1/4	.300	"
	23 1/2"O.D.	SA-335P-22	4 3/8"	Ellip.	2 3/4	SA-335P-22		"	.250	"
								Continued on		Page 2

9(a) Other Parts (1) Econ.Conn. (2) Attemperator (3) S.H.Conn. (4) .... 9(b) Tubes for Other Parts

(1) 4	8 5/8" O.D.	SA-106 B	3/4	Open						
(2) 2	14 1/4"O.D.	SA-335P-11	1 7/16	"						
2	13 3/4"O.D.	SA-335P-11	1 1/4	"						
(3) 1	13 3/4"O.D.	"	1 13/16	Open						

10 Openings (1) Steam 1—13 3/4" O.D. Weld Conn. (No., Size, and Type of Nozzles or Outlets)

(2) Safety Valve 3--2 1/2" Weld Conn. (No., Size, and Type of Nozzles or Outlets)

(3) Drain 2--2 1/2" Weld Conn. (No., Size, and Type of Nozzles or Outlets)

(4) Feed 2--8 5/8" Weld Conn. Econ. Inlet Hdr. (No., Size, Type, and Location of Connections)

11

	Bursting Press're Weakest Part	Maximum S.W.P.	Factor of Safety	Shop Hydro. Test	Heat'g Surface
a Boiler	9154.1	2225	4.11		3489
b Waterwall					13607
c Economizer					13507
d Superheater					86391
e Other Parts					

Heating surface to be stamped on drum heads.

This heating surface not to be used for determining minimum safety valve capacity

12 Field hydro. test
3338

BAW-1 PAGE 2

NB# 19517
2 of 4

		Headers		Heads or Ends						Tubes
No.	Size and Shape	Matl. Spec. No.	Thickness	Shape	Thickness	Matl. Spec. No.	Hydro. Test, lb.	Diamet'r	Thickn's	Matl. Spec. No.
								8 (b)	Superheater Tubes	
								2 1/4	.220	SA-210
								"	.210	"
								"	.200	"
								"	.275	SA-213T-11
								"	.345	SA-209T1a
								"	.280	"
								"	.215	"
								"	.335	SA-213T-11
								"	.180	SA-210
								2 1/2	.330	SA-213T-11
								"	.370	SA-213T-22
								"	.425	"
								"	.370	"
								"	.610	SA-213T-9

9(a) Other Parts (1).................(2).................(3).................(4)................. 9(b) Tubes for Other Parts

a										
b										
c										
d										

RECEIVED
MAY 23 1956
THE NATIONAL BOARD OF BOILER & PRESSURE VESSEL INSPECTORS

Appendix 2

FORM NO. P-3 MANUFACTURERS' DATA REPORT FOR WATER-TUBE BOILERS, SUPERHEATERS, WATERWALLS AND ECONOMIZERS

B&W-1 334-0284-22 As Required by the Provisions of the A.S.M.E. Code Rules 3 of 4

1. Manufactured by The Babcock & Wilcox Co., Barberton, Ohio (Name and address of manufacturer)
2. Manufactured for The New England Power Company Salem, Mass. (Name and address of purchaser)
3. Identification Reheat Section, With Radiant Heat Boiler (Type of boiler, superheater, waterwall, economizer) Boiler No. 19517 (Mfrs. Serial No.)

(State and State No.) Natl. Board No. 19517 Year Built 1957

4. The chemical and physical properties of all parts meet the requirements of material specifications of the A.S.M.E. Boiler Code. The design, construction, and workmanship conform to A.S.M.E. Rules Yes

Remarks: Manufacturers' Partial Data Reports properly identified and signed by Commissioned [stamp] the following items of this report: (Name of Part—Item number, manufacturer's name, and identifying stamp)

See Separate P-3 Data For Main Boiler Section

RECEIVED
MAY 23 1958
THE NATIONAL BOARD OF BOILER & PRESSURE VESSEL INSPECTORS

We certify the statement in this data report to be correct.

Date February 26, 1958 Signed The Babcock & Wilcox Co. (Manufacturer) By R. Ahlston (Representative)

Certificate of Authorization Expires December 31, 1958

CERTIFICATE OF BOILER SHOP INSPECTION

Insurance Companies' Serial Number HSB-19517

BOILER WORKS OF The Babcock & Wilcox Co. at Barberton, Ohio

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co. (All Tubes Shop Welds Only) of Hartford, Conn., have inspected parts of the boiler referred to as data items 8a, 9a, 10, 11 and have examined manufacturers' data for items and certify that the material, construction, and workmanship are in accordance with A.S.M.E. Boiler Code Rules.

DATE November 18, 1957 W. M. Loring Inspector Commissions NB# 2526 State or Natl. Board and No.

CERTIFICATE OF FIELD ASSEMBLY INSPECTION

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co. of Boston, have compared the statement in this manufacturers' data report with the described boiler and certify that parts referred to as data items 8b, 9a, 10, 12 ~~not included in certificate of shop inspection~~, are in accordance with the requirements of the A.S.M.E. Boiler Code. The described boiler was inspected and subjected to a hydrostatic test of 995 lb. per sq. in.

DATE 6-8-1958 N Burns Inspector Commissions NB# 2951 State or Natl. Board and No.

Appendix 2

FORM NO. P-3 MANUFACTURERS' DATA REPORT FOR WATER-TUBE BOILERS, SUPERHEATERS, WATERWALLS AND ECONOMIZERS

B&W-1 334-0284-22 As Required by the Provisions of the A.S.M.E. Code Rules 3 of 4

1. Manufactured by The Babcock & Wilcox Co., Barberton, Ohio
(Name and address of manufacturer)

2. Manufactured for The New England Power Company Salem, Mass.
(Name and address of purchaser)

3. Identification Reheat Section, With Radiant Heat Boiler Boiler No. 19517
(Type of boiler, superheater, waterwall, economizer) (Mfrs. Serial No.)

(State and State No.) Natl. Board No. 19517 Year Built 1957

4. The chemical and physical properties of all parts meet the requirements of material specifications of the A.S.M.E. Boiler Code. The design, construction, and workmanship conform to A.S.M.E. Rules Yes

Remarks: Manufacturers' Partial Data Reports properly identified and signed by Commissioned Inspectors have been furnished for the following items of this report:
(Name of Part—Item number, manufacturer's name, and identifying stamp)

See Separate P-3 Data For Main Boiler Section

RECEIVED
MAY 23 1958
THE NATIONAL BOARD OF BOILER & PRESSURE VESSEL INSPECTORS

We certify the statement in this data report to be correct.

Date February 26, 1958 Signed The Babcock & Wilcox Co. By R. A. Huston
(Manufacturer) (Representative)

Certificate of Authorization Expires December 31, 1958

CERTIFICATE OF BOILER SHOP INSPECTION

Insurance Companies' Serial Number HSB-19517

BOILER WORKS OF The Babcock & Wilcox Co. at Barberton, Ohio

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co. (All Tubes Shop Welds Only)

of Hartford, Conn., have inspected parts of the boiler referred to as data items 8a, 9a, 10, 11

and have examined manufacturers' data for items

and certify that the material, construction, and workmanship are in accordance with A.S.M.E. Boiler Code Rules.

DATE November 18, 1957 H. M. Loring Commissions NB# 2526
Inspector State or Natl. Board and No.

CERTIFICATE OF FIELD ASSEMBLY INSPECTION

I, the undersigned, inspector of steam boilers employed by The Hartford S.B.I. & I. Co.

of Boston, have compared the statement in this manufacturers' data report with the described boiler and certify that parts referred to as data items 8b, 9a, 10, 12

~~not included in certificate of shop inspection~~, are in accordance with the requirements of the A.S.M.E. Boiler Code. The described boiler was inspected and subjected to a hydrostatic test of 995 lb. per sq. in.

DATE 6-8, 1958 N. Burns Commissions NB# 2951
Inspector State or Natl. Board and No.

Appendix 2

5(a) DRUMS

No.	Nominal diameter Inches	Length Ft.	Length In.	Shell Plates: Brand	Material Spec. No.	Thickness	Inside Radius	Tube Sheets: Thickness	Inside Radius	Tube Hole Ligament Efficiency: Longitudinal	Circumferential
1											
2											
3											
4											

No.	Longitud'l Joints: No. & Type*	Effic'cy	Circum. Joints: No. & Type	Effic'cy	Heads: Brand	Material Spec. No.	Thickness	Type**	Radius of Dish	Manholes No.	Size	Hydro-static Test, lb.
1												
2												
3												
4												

* Indicate if 1. Seamless; 2. Fusion welded; 3. Forge welded; 4. Riveted. ** Indicate if 1. Flat; 2. Dished; 3. Ellipsoidal; 4. Hemispherical.

5(b) BOILER TUBES

Diamet'r	Thickn's	Material Specification No.

5(c) HEADERS No. ...... (Box or sinuous; Mat. Spec. No.; Thickness)

HEADS OR ENDS ...... (Shape; Mat. Spec. No.; Thickness) HYDRO. TEST-LB.

6(a) WATERWALL HEADERS — 6(b) WATERWALL TUBES

No.	Size and Shape	Matl. Spec. No.	Thickness	Heads or Ends: Shape	Thickness	Matl. Spec. No.	Hydro. Test, lb.	Diamet'r	Thickn's	Matl. Spec. No.

7(a) ECONOMIZER HEADERS — 7(b) ECONOMIZER TUBES

8(a) Reheat HEADERS — 8(b) Reheat TUBES

1	20 3/4"O.D.	SA-106 C	1 1/4"	Ellipt	1"	SA-106 C		2 1/4"	.150	SA-209T1a
1	21 3/4"O.D.	SA-335P-11	1 11/16"	"	1 1/16"	SA-335P-11		"	"	SA-213T-22
								"	.170	SA-213T-22
								"	.210	SA-213T-21
								2 1/2	.280	SA-209T1a
								"	.280	SA-213T-22
								"	.240	SA-213T-11
								Continued on Page 2		

9(a) OTHER PARTS (1) Reheat Conn. (2) ...... (3) ...... (4) ...... 9(b) TUBES FOR OTHER PARTS

(1) 2	20 3/4"O.D.	SA-106 C	1 1/4	Open						
2	20 3/4"O.D.	SA-335P-11	1 1/4	Open						

10 OPENINGS (1) Steam 2—20 3/4" O.D. Weld Conn. (No., Size, and Type of Nozzles or Outlets) (2) Safety Valve ...... (No., Size, and Type of Nozzles or Outlets)

(3) Blow-off ...... (No., Size, and Type of Nozzles or Outlets) (4) Feed 2—20 3/4" O.D. Weld Conn. Inlet Hdr. (No., Size, Type, and Location of Connections)

11		Bursting Press're Weakest Part	Maximum S.W.P.	Factor of Safety	Shop Hydro. Test	Heat'g Surface
a	Boiler					
b	Waterwall					
c	Economizer					
d	Reheater	2900	650	4.46		22,540
e	Other Parts					

Heating surface to be stamped on drum heads.
This heating surface not to be used for determining minimum safety valve capacity

12 Field hydro. test
975

334-0284-22

Appendix 2

B&W-1 PAGE 2 534-0284-22

NB# 19517
4 of 4

	Headers			Heads or Ends				Tubes		
No.	Size and Shape	Matl. Spec. No.	Thickness	Shape	Thickness	Matl. Spec. No.	Hydro. Test, lb.	Diamet'r	Thickn's	Matl. Spec. No.
								8 (b)	Reheat Tubes	
								2 3/4	.150	SA-210
								2 3/4	.200	"
								3"	.280	"

9(a) OTHER PARTS (1)............ (2)............ (3)............ (4)............ 9(b) TUBES FOR OTHER PARTS

a										
b										
c										
d										

..EIVED
MAY 23 1958
THE NATIONAL BOARD OF BOILER & PRESSURE VESSEL INSPECTORS

534-0284-22

Appendix 3

NUFIC BOILER/FIRED PRESSURE VESSEL—REPORT OF INSPECTION

NATIONAL UNION FIRE INSURANCE COMPANY
70 PINE STREET, NEW YORK, NEW YORK 10270

Standard Form For Jurisdictions Operating Under The ASME Code

NUFIC DESIGNATING NUMBER: Boiler 3

Row						
1	DATE INSPECTED (M9 Day Yr.): 04/10/2007	CERT EXP DATE (Mo Yr): 04/10/2008	CERTIFICATE POSTED: ☒ Yes ☐ No	OWNER NO: Boiler 3	JURISDICTION NUMBER:	☒ NATIONAL BOARD NO ☐ OTHER NO: NB19517
2	OWNER NAME: Dominion Energy Salem Harbor	NATURE OF BUSINESS: IPP Power Generation	KIND OF INSPECT: ☒ Int. ☐ Ext.	CERT INSPECTION: ☒ Yes ☐ No		
	OWNER STREET ADDRESS: 24 Fort Avenue	OWNERS CITY: Salem	STATE: MA	ZIP CODE: 01970		
3	USERS NAME AT OBJECT LOCATION: Dominion Energy Salem Harbor	SPECIFIC LOCATION IN PLANT: Powerhouse	OBJECT LOCATION-COUNTY: Essex			
	USERS STREET ADDRESS: 24 Fort Avenue	USERS CITY: Salem	STATE: MA	ZIP CODE: 01970		
4	TYPE: ☐ FT ☒ WT ☐ CI ☐ Other	YEAR BUILT: 1957	MANUFACTURER: Babcock and Wilcox			
5	USE: ☒ Power ☐ Process ☐ Steam Heating ☐ HWH ☐ Other:	FUEL: Coal	METHOD OF FIRING: Burner	PRESSURE GAGE TESTED: ☐ Yes ☒ No		
6	PRESSURE ALLOWED: This Inspection: 2,225 Previous Inspection: 2,225	SAFETY RELIEF VALVES: 2,225	EXPLAIN IF PRESSURE CHANGED:			
7	IS CONDITION OF OBJECT SUCH THAT A CERTIFICATE MAY BE ISSUED: ☒ Yes ☐ No *(If No, explain fully under conditions)*	HYDRO TEST *(If Yes, Give PSI and Date)*: ☐ Yes PSI: Date: ☒ No				

8 CONDITIONS: With respect to the internal surface, describe and state location of any scale, oil or other deposits. Give location and extent of any corrosion and state whether active or inactive. State location and extent of any erosion, grooving, bulging, warping, cracking or similar condition. Report on any defective rivets, bowed, loose or broken stays. State condition of all tubes, tube ends, coils, nipples, etc. Describe any adverse conditions with respect to pressure gage, water column, gage glass, gage cocks, safety valves, etc. Report conditions of setting linings, baffles, supports, etc. Describe any major changes or repairs made since last inspection.

There were no adverse conditions seen during this inspection.

Safety valve capacity – 1,000,000 lbs/hr
Heating surface – 40,603 sq. ft. (waterwalls)

9 REQUIREMENTS *(List Code Violations)*

There were no code violations.

10 NAME AND TITLE OF PERSON TO WHOM REQUIREMENTS WERE EXPLAINED

Steven Dulong, Operations Manager, 978-740-8264

I hereby Certify this is a true report of my inspection:

SIGNATURE OF INSPECTOR	IDENT. NO.	EMPLOYED BY	IDENT. NO.
RMaul Maule, Robert, A	1491	NATIONAL UNION FIRE INSURANCE	

NU963

Appendix 3

The Commonwealth of Massachusetts

CERTIFICATE OF INSPECTION

TYPE OF PRESSURE VESSEL WATER TUBE BOILER # 3

Date of Inspection SEPT 15, ~~19~~ 2005

Name of user DOMINION SALEM HARBOR

Location of vessel 24 FORT AVE
SALEM MA

Owners No. NB 19517

State No.

Year built 1957

Built by B+W

RE-INSPECTIONS

Kind	Date		Inspector
INT	08/29/2006	by	RMaul
INT	4/10/2007	by	RMaul
		by	
		by	
		by	

This is to certify that the pressure vessel herein described has been inspected for use in accordance with the provisions of G. L., C. 146 by

The Hartford Steam Boiler Inspection and Insurance Company

and may be operated at a

Pressure not to exceed 2,225 pounds per square inch.

Temperature not to exceed ________ °F (Hot Water Boilers only)

The Hartford Steam Boiler Inspection and Insurance Company

T. Stopwith Lewis
Vice President

Signature RMaul
Boiler Inspector

In accordance with Section 29, Chapter 146, General Laws, notify this company at once if any defect is discovered.

POST IN CONSPICUOUS PLACE IN ENGINE OR BOILER ROOM OR ADJACENT TO THE PRESSURE VESSEL.

2298 (DW 16B) 10/83 (ENG)

Enclosures

Furnace Lower Slope Dead Air Space

1 Conditions Found
No inspection was completed to the furnace lower slope dead air space this outage since it was not opened.

Future Recommendations (Priority: B)
1. Install new gunnite on all tube surfaces from which it has detached.

Furnace Upper Arch Dead Air Space

1 Conditions Found
The furnace upper arch dead air space was vacuumed this outage to allow access to replace upper arch tubing. All tubing was replaced across the boiler along the underside of the arch. Refractory was then reinstalled on the tube surfaces inside the arch.

Penthouse

1 Conditions Found
A partial inspection was completed in the penthouse as only a portion of its area was vacuumed. The area vacuumed was generally around the reheater and superheater outlet headers. Inspection to these headers and tube nipples revealed no indications of cracks at weld areas.

No other headers were inspected as they were either covered in ash or were covered with insulation. One hanger rod and collector beam located on the south end of the primary superheater outlet header was angled approximately 30° with the hanger rod actually bent at the bottom. The hanger assembly was recommended for repair. See Photo #5.4.3.1.1.

Future Recommendations (Priority: B)
1. Repair the east hanger rod and U-bolt on the primary superheater outlet header.

Appendix 5

The Commonwealth of Massachusetts
Department of Public Safety
One Ashburton Place, Room 1301
Boston, Massachusetts 02108-1618
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Deval L. Patrick
Governor

Timothy P. Murray
Lieutenant Governor

Kevin M. Burke
Secretary

Thomas G. Gatzunis, P.E.
Commissioner

November 19, 2007

Mr. Steve Dulong
Chief Engineer
Dominion Generation
24 Fort Avenue
Salem, MA 01970

RE: Boiler Certificate of Inspection

Dear Mr. Dulong:

Based on the condition of Boiler #3 located at the Salem Power Plant, 24 Fort Avenue, Salem, MA, it is the judgment of this inspector that Units #1, #2, #3 and #4 at that location are in a dangerous condition.

Therefore, this is formally notify you that pursuant to M.G.L. c. 146 § 21, all high pressure steam boilers the Salem Power Plant <u>are forbidden to be operated</u> until such time that a certificate of inspection has been issued by an inspector of the Department of public Safety.

As we have discussed, the Department is willing to inspect the boilers in a timely manner as to minimize the impact on the facility.

If you have any questions regarding this matter, please feel free to contact me.

Sincerely,

Mark F. Mooney
Chief of Inspections – Mechanical
Department of Public Safety

Cc: Mike Fitzgerald, Station Director

Failure Analysis
of Boiler Components from the Lower Dead Air Space
Salem Harbor, Unit 3
Dominion Energy
Salem, Massachusetts

A. Executive Summary

In response to the catastrophic failure of a component in the lower dead air space in Unit 3 at the Salem Harbor Steam Plant, the plant's owner, Dominion Energy, requested Structural Integrity Associates, Inc. (SI) to examine the portion of the component that was suspected of containing the initiation site and determine the cause of the failure. A visual survey had been performed by Dominion personnel, and the source of the damage was traced to the west end of the front division wall header. Based on that survey a section approximately 46" long was removed from the west end of the header for the laboratory examination.

Based on evidence obtained during the examination of the header and the attached tubing, it has been concluded that the failure initiated at the site of a weld defect in one of the nipple-to-division wall tube butt welds. It appears that this defect was present following the original construction of the unit. It is believed that in the course of the 48 years of the unit's operation the defect eventually grew to the point that a small steam leak developed, initiating a series of secondary leaks due to the steam cutting of adjacent tubes and culminating in the disruptive fracture of two of the nipples.

There was no evidence uncovered during the examination of the header and tubing to indicate that either excessive wall thinning due to external corrosion, or waterside corrosion-fatigue cracking, or base metal defects had played any role in the failure.

It has been emphasized that leaks in tubular butt welds in high pressure boilers are relatively rare, and that when they do occur they seldom result in damage as extensive as that which occurred at Salem Harbor 3. The evidence gathered during the metallurgical examination of the header and tubing indicates that the pattern of steam cutting that developed as a result of the first leak was unusually destructive, instigating a damage process that resulted in the complete rupture of two (2) sections of tubing, rather than additional localized leakage, which is the more common result.

Where there is concern that similar defects may be present in other tubular butt welds, non-destructive inspection techniques exist for identifying those defects. They include radiography, enhanced ultrasonic testing, or a combination of both.

Appendix 7

B. Technical Summary

Following the catastrophic failure of a boiler component in the lower dead air space of Unit 3 at Dominion Energy's Salem Harbor Steam Plant, a portion of one end of the lower division wall header, which included the full length of the nipples and approximately 2-3" lengths of the attached division wall tubes, was removed from the unit and submitted to Structural Integrity Associates, Inc. for laboratory examination. Dominion Energy requested that all necessary tests be conducted on the header sample to determine, first, where the failure had originated and, second, what was the nature of the condition that had instigated the failure. Both the header and the attached tubing reportedly were original equipment, and at the time of the failure Unit 3 had operated for approximately 48 years.

The section removed was from the west end of the header and was approximately 46" long. This section was selected for examination by site investigators because the pattern of consequential damage visible within a well-defined area in the approximate center of the removed section pointed to this location as the likely failure origin. What could not be determined based solely on a visual inspection of the damage to the header and tubing was the failure initiation site. Complicating the examination was the fact that large portions of two of the nipple tubes located within the apparent failure origin area – the tubes designated Tubes 10 and 11 – had separated completely from the header during the failure event, and the dislodged piece (or pieces) from the nipple from Tube 11 had not been recovered at the time of the analysis.

In the course of the investigation of the header and tube sections, various hypotheses that had been advanced to explain the failure were evaluated in the light of the physical evidence obtained during both non-destructive inspections and destructive examination of selected areas of the header and tubing. For example, one suspected cause of failure was that one of the division wall nipple tubes had ruptured after losing a substantial amount of its original wall thickness due to external corrosion; the corrosion was assumed to have been caused by prolonged exposure to reactive species in the ash that had accumulated in the dead air space. This hypothesis, which appeared to be consistent with the heavily pitted appearance of the external surfaces of both the header body and the tubing, was considered and then dismissed when extensive wall thickness readings demonstrated that none of the tubes had suffered sufficient wall loss, due to either external or internal corrosion, to jeopardize their continued

Appendix 7

reliable operation. Another proposed explanation for the failure focused on the backing rings that had been used during the fabrication of the nipple-to-division wall tube butt welds. This suggestion was plausible because these rings have been linked to the preferential formation of corrosion-fatigue cracks in welds in water-touched surfaces, and if such a crack were to propagate through the wall of one of the tubes at a weld, it could initiate a small leak that could then trigger extensive consequential damage. However, no evidence of corrosion-fatigue cracking was detected in any of the tubular welds supplied with the header section.

For the reasons stated, it was possible to eliminate excessive wall loss and corrosion-fatigue cracking as possible explanations for the initial leak. The assessment therefore considered other possible reasons for the fluid leakage. One possibility was the existence of a mill-type defect in the base metal of either the header body or one of the tubes. Another possibility was the presence of a defect in one of the nipple-to-header seal welds or one of the nipple-to-division wall tube butt welds.

With regard to the possibility that a base metal defect was responsible for the failure, careful and thorough examination of the available materials revealed no evidence to indicate that a defect in either the header body or in any one of the division wall tubes had played any role in the failure. It should be noted, however, that the missing piece, or pieces, of the nipple from Tube 11 could not be included in the evaluation.

With regard to the possibility that a weld defect was responsible for initiating the series of leaks and steam cutting that culminated in the catastrophic failure at the division wall header, here the analysis of the sample material provided persuasive evidence that such a defect was the point of origin for the failure. In particular, during the analysis an area of entrapped slag and lack-of-fusion along the nipple-side fusion boundary was identified at the root of the nipple-to-division wall tube butt weld for Tube 9. This defect was oriented in a direction that was consistent with the pattern of steam cutting damage observed on the adjoining nipple tubes and header body. Because the area of the weld where the defect in Tube 9 was located had suffered substantial steam cutting damage from a secondary leak site located on an adjoining tube, it was not possible to identify an intact leak path extending from the defect to the original outer surface of the weld. However, the size of the defect in the portion of the weld that survived the steam cutting damage, which exceeded the size of similar defects detected in any of the other welds examined from the header sample, and its favorable orientation with respect to the critical secondary damage to nipple Tubes 10 and 11, are compelling pieces of evidence pointing to this defect as the initiating source of the failure.

Based on the evidence obtained, a likely sequence of events that would explain the magnitude of the damage is as follows: during the fabrication of the nipple-to-division wall tube butt weld for Tube 9 a weld defect formed near the root of the weld; in this case the defect consisted of entrapped slag and lack-of-fusion along the nipple-side fusion boundary. Over the course of the many years of operation of the Unit 3 boiler at Salem Harbor, the defect grew in size, due to the interaction of corrosion and stress with intermittent discontinuities in the remaining intact ligament of weld metal, until finally it penetrated through the thickness of the weld and a small steam leak initiated. This original leak then caused steam cutting of one or more of the adjacent tubes (Tubes 10 and 11 being favorably oriented targets) until a second consequential leak formed, at which point a complex pattern of ricocheting steam (with entrained ash particles) was created. This then triggered further steam cutting of adjoining tubes and the header body, itself, and culminated in the disruptive fracture of nipple Tubes 10 and 11. At this point, events associated with the failure process are less certain. It is possible that the rapid release of steam from Tubes 10 and 11 pressurized the dead air space, which then ruptured, leading to an abrupt release of energy of sufficient magnitude to cause the extensive damage to the lower end of the unit that was observed in the aftermath of the failure.

One piece of potentially significant evidence uncovered during the examination of the nipple-to-division wall tube butt welds was the fact that all fifteen of the butt welds examined appeared to have had weld metal added to their outer surface at some time after their initial fabrication. In all cases the deposition of this supplemental weld metal was offset toward the division wall tube side of the joint (the side opposite the lack-of-fusion defects in Tubes 1, 7, and 9). This suggests that the intent was to reinforce the fusion boundary area on that side of the weld. Since it was reported by Dominion Energy that no records of supplemental welding exist, the reason and timing for this added weld metal could not be determined.

If the catastrophic failure was, in fact, instigated by the weld defect in the nipple-to-division wall tube butt weld for Tube 9, as appears likely, it is important to understand the context of such failures. The ASME Boiler & Pressure Vessel Code, which establishes the rules

Appendix 7

governing the fabrication and testing of such welds for service in high pressure boilers, did not at the time of the construction of the Salem Harbor unit, require non-destructive inspection of these welds prior to service. The stated reason for this exemption is that under normal circumstances these welds operate at low stresses and have proven to be highly tolerant of the types of defect that are not infrequently encountered in fusion welds for carbon and low alloy steels. Extensive industry experience has supported this exemption, since the number of significant failures caused by weld defects in tubular butt welds has been very small. While there have been occasional leaks in tubular butt welds, when such leaks occur they normally cause only a limited amount of consequential damage in surrounding tubes, which then leads to an orderly shut-down of the unit because of the difficulty in supplying sufficient make-up water. In this case, however, it appears that the initial leak resulted in a highly unusual pattern of steam cutting damage that resulted, not in additional leakage, but in the complete rupture of two adjoining tubes, with all of the disruptive consequences of so massive and rapid a release of energy within an enclosed space.

h. Six (6) plastic bags containing samples of external deposit/corrosion product that were removed from selected areas on the header body. The bags were identified as follows:

- Northwest end of header at 9 o'clock position (171-1306)
- East end of header at 9 o'clock position (1309)
- Center of header at 9 o'clock position (1308)
- Tube 11, 2' above header (1311)
- Tube 1, just above weld (--)
- Tube 7, 2' above weld (1312)
- Tube 8, 2' above weld (1310)
- Between Tubes 5 and 7 at 12 o'clock position (171-1307)

Photographs of typical examples of the deposit that had been removed are presented in "Section G: Destructive Examination".

II. Visual Inspection

Prior to the beginning of the testing that would alter the surface condition of the samples, each sample was inspected visually to characterize its general appearance and to identify distinctive features that might serve as points of interest for the ensuing non-destructive and destructive phases of the investigation. The results of the visual inspection are described in detail below.

Header Body Segment and Loose Tube Sections

1. External Surfaces - Corrosion

In viewing the external surfaces of the header body and the attached tubing, it was apparent that both the header and tubes had suffered some measurable amount of wastage due to external corrosion, with signs of widespread pitting attack visible on all surfaces. Examples of the surface corrosion are documented in Figures 13 and 14. There was no obvious pattern to the surface corrosion that would indicate an operational influence; instead, evidence of attack was visible around the circumference and along the length of the header body segment, and along the full length of the tube sections. An inspection of the cut ends of the division wall and supply tubes indicated that the overall amount of wall loss due to the external corrosion was not severe, and a preliminary measurement of the remaining wall thickness of several of the division wall tubes at the cut ends indicated that in no case was the remaining wall thickness less than approximately 0.180".

The surface deposits and corrosion product remaining on the header and tube surfaces varied in thickness, color, and the tenacity with which they adhered to the surface of the header or tubing. The color of the surface deposits varied from a light tan color to reddish/brown and reddish/gray, reflecting in large part differences in the amount of loose fly ash and other extraneous debris accumulated in the dead air space that had become embedded in the surface deposits during the failure event. As with the corrosion attack, itself, there was no clear pattern to be discerned in the distribution of the deposits and corrosion product along the length and around the circumference of the header body or along the length of the tubes, with all areas of the header body segment and tubing exhibiting measurable accumulations of deposit and corrosion product.

2. External Surfaces – Steam-Cutting Damage

Evidence of surface damage due to steam cutting was visible in an area that was centered on the missing nipples from Tubes 10 and 11, but that extended to include an area bounded by Tubes 9 to 12. This cutting was the result of the impingement of escaping steam containing entrained ash particles on exposed metal surfaces, and it had caused substantial localized damage to the surfaces of both the header and the tubing in that area. On the header body, itself, some of the most severe damage was located near the base of Tube 9, as shown in Figure 15. The pattern of the cutting indicated that this damage was caused by steam escaping from a point near the nipple-to-header weld on the north-east side of Tube 9. The point of leakage near the base of Tube 9 was itself an area that had been severely eroded by steam cutting, suggesting that this leakage was a consequence of damage from yet another site.

There was extensive steam cutting damage on the north side of Tube 9 (i.e., the side facing Tube 11), with damage of varying degrees of severity visible from approximately 2" above the nipple-to-DW tube butt weld down to the header body. This cutting had opened an obliquely-angled slit in the division wall tube just above the butt weld and had created a local area of gouging just below the butt weld, as documented in Figure 16. In both major areas of steam cutting damage at and near the butt weld, the pattern of the damage was consistent with cutting from a source away from Tube 9. Another hole had been opened just above the nipple-to-header seal weld in this tube, as shown in the upper photograph in Figure 16. Note that the edges of the hole are protruded outward, indicating that at the time the hole opened there still was substantial internal pressure acting on the tube.

On the segment of DW tubing from Tube 10, evidence of steam cutting was visible just above the butt weld on one side of the tube extending from the point of separation between the butt weld and the nipple tube upward approximately 11" along the length of the tube. The cutting damage was most severe at a point approximately 4" above the butt weld, where a hole had formed in the tube, the edges of which were deformed outward. Above the butt weld evidence of the cutting was observed approximately 180 degrees around the circumference of the tube. At the point of separation between the weld area and the nipple tube the area affected by the cutting extended approximately 100 degrees around the circumference. Based on the description of the orientation of this tube section

Sample 8: 12 o'clock Position Between #5 and #7 (171-1307)
Outer surface – the bulk of the material visible at this surface was reddish-gray in color and was covered by a translucent glassy deposit that, in turn, was covered by a thin coat of tan-colored fly ash particles; there also were a number of whisker-shaped particles present on the surface.

Inner surface – the appearance at this surface was similar to that of the same surface on **Sample 6,** as described above.

Sample 9: Tube 5 Header Outlet
This sample consisted of a small scraping of "typical" deposit from the OD surface of Tube 5; it was removed for comparison with the distinctive white-colored deposit that had accumulated at one location on the surface of the tube. The scraping consisted of a number both tan and gray colored particles that were similar in size and shape to particles visible on all of the tube surfaces.

Sample 10: Tube 5 Header Outlet White Deposit
This sample consisted of scrapings from a distinctive white-colored deposit that concentrated in one area of Tube 5. The material scraped from the surface was powder-like in consistency.

II. External Deposit/Scale Accumulations

b. Results of EDS and XRD Analyses

Representative specimens of the deposits were selected from each of the sample bags for analysis using either EDS or XRD. The majority of the analyses were performed using EDS, and the primary objective of these analyses was to characterize the overall elemental composition of the bulk material on both the outside and inside surfaces, and to examine in greater detail any unusual material formations that appeared different from the bulk material. The results of these analyses are presented in Table 3. In a few selected cases, particularly those containing the glassy-type deposit that was observed on the surface of a number of the samples, specimens were submitted for analysis by XRD, and the results of these analyses are presented in Table 4.

A review of the results of the compositional analyses recorded in the tables reveals that in virtually all cases the deposit/scale accumulations were a mixture of elements associated with combustion by-products, such as sulfur, silicon, sodium, potassium, and calcium, and iron oxides. The large amounts of sulfur and iron oxide are consistent with the observations regarding the surface corrosion, which was believed to have been caused by acid attack related to the wetting of reactive elements in the deposit, and particularly sulfur, during periods when the unit was not operating. The translucent, glassy material that was observed on many of the specimens appeared to consist largely of organic material, which can be only imperfectly characterized by EDS. For this reason specimens of the translucent material were submitted for XRD. The XRD results provided no clear indication of the source of the glassy material. However, the white-colored compound observed on Tube 5 was identified as urea, a material that reportedly was injected intentionally into the fuel train during normal operation of the boiler. Reports from the plant following the failure indicated that the injection of the urea had continued for some time after the unit had tripped off line, so that the presence of the urea in the deposit material appears to be a secondary effect of the failure and is not considered in any way unusual.

III. Chemical Analysis

a. Header and Tubing Material

Specimens were removed from the header body and from selected nipple and DW tubes for quantitative compositional analysis. The purpose of these analyses was to verify that the specified material had been installed and that there were no compositional anomalies that could have adversely affected the service performance of the header or the tubing.

The results of the compositional analyses are presented in Table 5. As shown in this table, in all cases the compositions were consistent with the carbon steel grades that had been specified according to the original design drawings. The levels of residual and other non-specified elements were within "normal" ranges for these grades of steel produced at the time the unit was constructed, and there was nothing in the compositions to suggest a potentially significant material deficiency.

b. Weld Metal

The chemical composition of the weld metal deposited when making the nipple-to-header seal welds and the nipple-to-DW tube butt welds was evaluated using EDS. The purpose of these analyses was twofold: first, to verify that the filler material used in making the welds was compatible with the base metal; and, second, with respect to the nipple-to-DW tube butt welds, to compare the composition of the material near the root pass, which appeared to be "original" weld metal, with the composition of the material at the weld cap, which appeared to have been added at some later time.

The results of the chemical analyses of the weld metal specimens are presented in Tables 6 and 7. As shown in these tables, in all cases the weld metal compositions, as determined by EDS, were consistent with the use of a carbon steel filler metal and were, therefore, appropriate for the application. A comparison of the compositions of the root and cap passes in the butt welds confirmed that the two materials were

Appendix 10

The Commonwealth of Massachusetts
Department of Public Safety
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Deval L. Patrick
Governor

Timothy P. Murray
Lieutenant Governor

Kevin M. Burke
Secretary

Thomas G. Gatzunis, P.E.
Commissioner

November 28, 2007

Mr. Robert Maule
[redacted]

RE: Dominion Generation Power Plant – Salem Harbor Plant Inspection

Dear Mr. Maule:

Pursuant to G.L. c. 146, the Department of Public Safety (the Department) is investigating the failure of Boiler Unit #3 at the Salem Harbor Plant on November 6, 2007. As part of this investigation, the Department is requesting the following information:

1. Any and all inspection reports for all inspections performed in calendar year 2007 on Boiler Units nos. 1-4 at the Salem Power Plant located at 24 Fort Avenue, Salem, Massachusetts.
2. Any and all notes and related inspectional documentation, photographs and/or videotapes that you may have with regard to the inspections you performed on Boiler Units 1-4 at 24 Fort Avenue, Salem, Massachusetts in calendar year 2007.
3. A detailed list and location of what confined spaces you entered in order to perform the inspections on Units 1-4 at the above location in calendar year 2007.

Please submit this information to my attention on or before December 9, 2007.

Sincerely,

Mark F. Mooney
Chief of Inspections-Mechancal

ATTACHMENT A

List of Confined Spaces Entered To Perform
Calendar Year 2007 Boiler Number 1-4 Inspections

Boiler Number 1
Superheater assembly spaces
Reheater assembly spaces
Convective pass spaces
Furnace

Boiler Number 2
Steam drum
Superheater assembly spaces
Reheater assembly spaces
Convective pass spaces
Furnace

Boiler Number 3
Steam drum
Superheater assembly spaces
Reheater assembly spaces
Convective pass spaces
Furnace

Boiler Number 4
Steam drum
Superheater assembly spaces
Reheater assembly spaces
Convective pass spaces

PART RB
INSERVICE INSPECTION

RB-2000 PERSONNEL SAFETY

RB-2010 SCOPE

The owner/user and Inspector shall determine that the pressure-retaining items may be entered safely. This shall include:

a. potential hazards associated with entry into the object have been identified by the owner/user and are brought to the attention of the Inspector, along with acceptable means or methods for dealing with each of these hazards;

b. coordination of entry into the object by the Inspector and an owner/user representative(s) working in or near the object;

c. if personal protective equipment is required to enter an object, the necessary equipment is available, and the Inspector is properly trained in its use;

d. an effective energy isolation program is in place and in effect that will prevent the unexpected energizing, start up or release of stored energy (lock out and/or tag out);

e. all applicable safety regulations are otherwise being followed. This includes applicable governmental, state, regional, and/or local rules and regulations. The owner/user programs or the Inspectors' employers' safety programs or similar regulations also apply. In the absence of such rules, prudent and generally accepted engineering safety procedures satisfactory to the Inspector shall be employed by the owner/user.

RB-2020 INTERNAL INSPECTION, BOILERS

a. When a boiler is to be prepared for internal inspection, the water should not be withdrawn until the setting has been sufficiently cooled at a rate to avoid damage to the boiler.

b. The owner or user should prepare a boiler for internal inspection in the following manner:

1. The fuel supply and ignition system shall be locked out and/or tagged out, in accordance with the owner/users procedures.

2. Water shall be withdrawn and the water side thoroughly washed.

3. Manhole and handhole plates, washout plugs, as well as inspection plugs in water column connections shall be removed as required by the Inspector. The boiler shall be cooled and thoroughly cleaned.

4. Any leakage of steam or hot water into the boiler shall be prevented by disconnecting the pipe or valve at the most convenient point or any appropriate means approved by the Inspector.

5. Before opening the manhole(s) and entering any part of a boiler which is connected to a common header with

PART RB
INSERVICE INSPECTION

RB-3100 INSPECTION OF BOILERS

RB-3110 GENERAL CONDITIONS

a. Boilers are designed for a variety of service conditions. The temperature and pressure at which they operate should be considered in establishing inspection criteria. This part is provided for guidance of a general nature. There may be occasions where more detailed procedures will be required.

b. The condition of the complete installation, including maintenance and operation, can often be used by the Inspector as a guide in forming an opinion of the care given to the boiler.

c. Usually the conditions to be observed by the Inspector are common to both power and heating boilers, however, where appropriate, the differences are noted.

RB-3120 PRE-INSPECTION ACTIVITIES

a. A review of the known history of the boiler should be performed. This should include a review of information, such as:

1. Operating conditions
2. Date of last inspection
3. Current jurisdictional inspection certificate
4. ASME Code Symbol Stamping or mark of code of construction
5. National Board and/or jurisdiction registration number

b. The following parts should be removed as required to permit the inspection:

1. Manhole and handhole plates
2. Washout plugs
3. Inspection plugs in water column connectors
4. Grates of internally fired boilers
5. Insulation and brickwork, as appropriate
6. Pressure gage should be removed for testing, unless there is other information to assess it's accuracy.

c. The boiler shall be cooled and thoroughly cleaned.

RB-3130 ASSESSMENT OF INSTALLATION, CAUSES OF DETERIORATION, TYPES OF DEFECTS

RB-3131 ASSESSMENT OF INSTALLATION

The external inspection of a boiler is made to determine if it is in a condition to operate safely. Upon entering the boiler area, the general cleanliness and accessibility of the boiler and its auxiliary apparatus should be noted. The boiler fittings, valves and piping should be checked for compliance with ASME Code or other standards or equivalent requirements.

RB-3132 CAUSES OF DETERIORATION

Deterioration of boilers may be caused by improper or inadequate water treatment, excessive fluctuations in pressure or temperature, or improper or lack of maintenance.

RB-3133 TYPES OF DEFECTS

Defects may include bulged or blistered plates, cracks or other defects in welds or heat-affected zones, pinhole leaks, improper or inadequate safety devices, wasted or eroded material.

atmosphere is obtained. All necessary precautions shall be taken to eliminate the possibility of explosion or fire.

d. When a vessel is connected in a system where there is the presence of liquid or gases, the vessel shall be isolated by closing, locking and/or tagging stop valves. When toxic or flammable materials are involved, additional safety precautions may require removing pipe sections or blanking pipelines before entering the vessel. The means of isolating the vessel shall be acceptable to the Inspector and in compliance with applicable occupational safety and health regulations and procedures.

e. Prior to entering a vessel that contained toxic or flammable gases or an inert atmosphere, the vessel atmosphere shall be tested by qualified personnel using appropriate atmospheric testing instruments.

f. Personal protective equipment and clothing shall be worn as appropriate. This may include, among other items, protective outer clothing, gloves, eye protection, and foot protection. The atmosphere of the vessel shall be tested to determine if respiratory protection is required. The Inspector shall have the proper training governing the selection and use of any personal protective equipment necessary to safely perform each inspection.

g. If requested by the Inspector or required by regulation or applicable procedure, a responsible person ("attendant") shall remain outside the vessel at the point of entry while the Inspector is inside and shall monitor activity inside and outside and communicate with the Inspector as necessary. The attendant shall have a means of summoning assistance if needed and to facilitate rescue procedures for those inside the vessel without personally entering the vessel.

IF A VESSEL HAS NOT BEEN PROPERLY PREPARED FOR AN INTERNAL INSPECTION, THE INSPECTOR SHALL DECLINE TO MAKE THE INSPECTION.

flange where there may be repeated flexing of the plate during operation and around welded pipe and tube connections.

d. Lap joint boilers are subject to cracking where the plates lap in the longitudinal seam. If there is any evidence of leakage or other distress at this point, the Inspector should thoroughly examine the area and, if necessary, have the plate notched or slotted in order to determine whether cracks exist in the seam. Repairs of lap joint cracks on longitudinal seams are prohibited.

e. Where cracks are suspected, it may be necessary to subject the boiler to nondestructive examination to determine their location.

RB-3158 CORROSION

a. Corrosion causes deterioration of the metal surfaces. It can affect large areas or it can be localized in the form of pitting. Isolated, shallow pitting is not considered serious if not active.

b. The most common causes of corrosion in boilers are the presence of free oxygen and dissolved salts in the feedwater. Where active corrosion is found, the Inspector should advise the owner or user to obtain competent advice regarding proper feedwater treatment.

c. For the purpose of estimating the effect of severe corrosion over large areas on the safe working pressure, the thickness of the remaining sound metal should be determined by ultrasonic examination or by drilling.

d. Grooving is a form of metal deterioration caused by localized corrosion and may be accelerated by stress concentration. This is especially significant adjacent to riveted joints.

e. All flanged surfaces, should be inspected, particularly the flanges of unstayed heads. Grooving in the knuckles of such heads is common since there is slight movement in heads of this design which causes a stress concentration.

f. Some types of boilers have ogee or reversed-flanged construction which is prone to grooving and may not be readily accessible for examination. The Inspector should insert a mirror through an inspection opening to examine as much area as possible. Other means of examination such as the ultrasonic method may be employed.

g. Grooving is usually progressive and when it is detected, its effect should be carefully evaluated and corrective action taken.

h. The fireside surfaces of tubes in horizontal firetube boilers usually deteriorate more rapidly at the ends nearest the fire. The Inspector should examine the tube ends to determine if there has been serious reduction in thickness. The tube surfaces in some vertical tube boilers are more susceptible to deterioration at the upper ends when exposed to the heat of combustion. These tube ends should be closely examined to determine if there has been a serious reduction in thickness. The upper tube sheet in a vertical "dry top" boiler should be inspected for evidence of overheating.

i. Pitting and corrosion on the waterside surfaces of the tubes should be examined. In vertical firetube boilers excessive corrosion and pitting is often noted at and above the water level. Excessive scale on waterside surfaces should be removed before the boiler is placed back in service.

j. The surfaces of tubes should be carefully examined to detect corrosion, erosion, bulges, cracks, or evidence of defective welds. Tubes may become thinned by high velocity impingement of fuel and ash particles or by the improper installation or use of soot blowers. A leak from a tube frequently causes serious corrosion or erosion on adjacent tubes.

k. In restricted fireside spaces such as where short tubes or nipples are used to join drums or headers, there is a tendency for fuel and ash to lodge at junction points. Such deposits are likely to cause corrosion if moisture is present and the area should be thoroughly cleaned and examined.

RB-3159 MISCELLANEOUS

a. The piping to the water column should be carefully inspected to ensure that water cannot accumulate in the steam connection. The position of the water column should be checked to determine that the column is placed in accordance with ASME Code or other standard or equivalent requirements.

b. The gas side baffling should be inspected. The absence of the proper baffling or defective baffling can cause high temperatures and overheat portions of the boiler. The location and condition of combustion arches should be checked for evidence of flame impingement which could result in overheating.

c. Any localization of heat caused by improper or defective installation or improper operation of firing equipment should be corrected before the boiler is returned to service.

d. The supports and settings should be carefully examined, especially at points where the boiler structure comes near the setting walls or floor, to make sure that deposits of ash or soot will not bind the boiler and produce excessive strains on the structure due to the restriction of movement of the parts under operating conditions.

e. When tubes have been rerolled or replaced, they should be inspected for proper workmanship. Where tubes are readily accessible, they may have been over rolled. Conversely, when it is difficult to reach the tube ends they may have been under rolled.

RB-3160 GAGES, SAFETY DEVICES, AND CONTROLS

RB-3161 GAGES

a. Ensure that the water level indicated is correct by having the gage tested as follows:

1. Close the lower gage glass valve, then open the drain cock and blow the glass clear.

2. Close the drain cock and open the lower gage glass valve. Water should return to the gage glass immediately.

3. Close the upper gage glass valve, then open the drain cock and allow the water to flow until it runs clean.

4. Close the drain cock and open the upper gage glass valve. Water should return to the gage glass immediately.

b. If the water return is sluggish, the operation should be repeated. A sluggish response could indicate an obstruction in the pipe connections to the boiler. Any leakage at these fittings should be promptly corrected to avoid damage to the fittings or a false waterline indication.

c. Each hot water boiler should be fitted with a temperature gage at or near the boiler outlet that will at all times indicate the water temperature.

d. Where required, all the pressure gauges shall be removed, tested and their readings compared to the readings of a standard test gage or a dead weight tester.

e. The location of a steam pressure gage should be noted to determine whether it is exposed to high temperature from an external source or to internal heat due to lack of protection by a proper siphon or trap. The Inspector should check that provisions are made for blowing out the pipe leading to the steam gage.

RB-3263 CONTROLS

a. Any control device attached to a vessel should be demonstrated by operation or the Inspector should review the procedures and records for verification of proper operation.

b. Temperature measuring devices should be checked for accuracy and general condition.

RB-3270 RECORDS REVIEW

a. The Inspector should review any pressure vessel log, record of maintenance, corrosion rate record or any other examination results. The Inspector should consult with the Owner or User regarding repairs or alterations made, if any, since the last internal inspection. The Inspector should review the records of such repairs or alterations for compliance with applicable requirements.

b. A permanent record shall be maintained for each pressure vessel. This record shall include the following:

1. An ASME Manufacturers' Data Report or, if the vessel is not ASME Code stamped, other equivalent specifications.

2. Form NB-5 Boiler or Pressure Vessel Data Report - First Internal Inspection, may be used for this purpose. It shall show the following identification numbers as applicable.

   National Board No.
   Jurisdiction No.
   Manufacturer's Serial No.
   Owner-User's No.

3. Complete pressure relieving device information including safety or safety relief valve spring data or rupture disk data, and date of latest inspection.

4. Progressive record including, but not limited to, the following:

   a. Location and thickness of monitor samples and other critical inspection locations.

   b. Limiting metal temperature and location on the vessel when this is a factor in establishing the minimum allowable thickness.

   c. Computed required metal thicknesses and maximum allowable working pressure for the design temperature and pressure relieving device opening pressure, static head, and other loadings.

   d. Test pressure if tested at the time of inspection.

   e. Scheduled (approximate) date of next inspection

   f. Date of installation and date of any significant change in service conditions (pressure, temperature, character of contents or rate of corrosion);

   g. Drawings showing sufficient details to permit calculation of the service rating of all components on pressure vessels used in process operations subject to corrosive conditions. Detailed data with sketches where necessary may serve this purpose when drawings are not available.

RB-3280 CONCLUSIONS

Any defect or deficiency in the condition, operating and maintenance practices of the pressure vessel should be discussed with the owner or user at the time of inspection and, if necessary, recommendations made for the correction of such defect or deficiency.

Appendix 18

RB-1000 GENERAL REQUIREMENTS FOR INSERVICE INSPECTION OF PRESSURE-RETAINING ITEMS

RB-1010 SCOPE

Part RB provides guidelines and requirements for conducting inservice inspection and testing of pressure-retaining items and pressure relief devices. Appropriately, this Part includes precautions for the safety of inspection personnel. The safety of the Inspector is the most important aspect of any inspection activity.

Understanding the potential damage/deterioration mechanisms that can affect the mechanical integrity of a pressure-retaining item and knowledge of the inspection methods that can be used to find these damage mechanisms are essential to an effective inspection. This Part includes a general discussion of various damage mechanisms and effective inspection methods. In addition, some specific guidance is given on how to estimate the remaining life of a pressure-retaining item and determine the appropriate inspection interval.

RB-1020 ADMINISTRATION

Jurisdictional requirements describe the frequency, scope, type of inspection, whether internal, external or both, and type of documentation required for the inspection. The Inspector shall have a thorough knowledge of jurisdictional regulations where the item is installed, as inspection requirements may vary.

RB-1030 STAMPING

Authorization
When the stamping on a pressure-retaining item becomes indistinct or the nameplate is lost, illegible, or detached, but traceability to the original pressure-retaining item is still possible, the Inspector shall instruct the owner or user to have the stamped data replaced. All re-stamping shall be done in accordance with the original code of construction, except as modified herein. Requests for permission to re-stamp or replace nameplates shall be made to the jurisdiction in which the pressure-retaining item is installed. Application must be made on the Replacement of Stamped Data Form NB-136 (Appendix 5). Proof of the original stamping and other such data, as is available, shall be furnished with the request. Permission from the jurisdiction is not required for the reattachment of nameplates that are partially attached. When traceability cannot be established, the jurisdiction shall be contacted.

When there is no jurisdiction, the replacement of stamped data shall be authorized and witnessed by a National Board Commissioned Inspector and the completed Form NB-136 shall be submitted to the National Board.

Replacement of Stamped Data
The restamping or replacement of data shall be witnessed by a National Board Commissioned Inspector and shall be identical to the original stamping.

The restamping or replacement of a code symbol stamp shall be performed only as permitted by the governing Code of Construction. **A06**

Replacement nameplates shall be clearly marked "replacement."

Reporting
Form NB-136 shall be filed with the jurisdiction (if required) or the National Board by the owner or user together with a facsimile of the stamping or nameplate, as applied, and shall also bear the signature of the National Board Commissioned Inspector who witnessed the replacement.

RB-1040 REFERENCE TO OTHER CODES AND STANDARDS

Other existing inspection codes, standards and practices pertaining to the inservice inspection of pressure-retaining items can provide useful information and references relative to the inspection techniques listed in Part RB. Additionally, supplementary guidelines for assisting in the evaluation of inspection results and findings are also available. Some acceptable guidelines are as follows:

a. National Board *BULLETIN* – National Board Classic Articles Series

b. American Society of Mechanical Engineers – *ASME Boiler & Pressure Vessel Code* Section V (Nondestructive Examination)

c. American Society of Mechanical Engineers – *ASME Boiler & Pressure Vessel Code* Section VI (Recommended Rules for the Care and Operation of Heating Boilers)

d. American Society of Mechanical Engineers – *ASME Boiler & Pressure Vessel Code* Section VII (Recommended Guidelines for the Care of Power Boilers Subsection C6 - Inspection)

e. American Society of Mechanical Engineers – ASME B31G (Manual for Determining the Remaining Strength of Corroded Pipelines)

f. American Petroleum Institute – API 572 Inspection of Pressure Vessels

g. American Petroleum Institute – API 574 Inspection Practices for Piping System Components

h. American Petroleum Institute – API 579 Fitness-For-Service

RB-1050 CONCLUSIONS

During any inspections or tests of pressure-retaining items, the actual operating and maintenance practices should be noted by the Inspector and a determination made as to their acceptability.

Defects or deficiencies in the condition, operating and maintenance practices of the boiler, pressure vessel or piping system equipment should be discussed with the owner or user at the time of inspection and recommendations made for correction of any such defects or deficiencies.

RB-2000 PERSONNEL SAFETY AND INSPECTION ACTIVITIES

Visual examination is the basic method used when conducting an inservice inspection of pressure-retaining items. Additional examination and test methods may be required at the discretion of the inspector to provide additional information to assess the condition of the pressure-retaining item. See RB-3000. A04

RB-2010 SCOPE

A proper inspection of a pressure-retaining item requires many pre-inspection planning activities including: safety considerations, an inspection plan that considers the potential damage mechanisms, selection of appropriate inspection methods and awareness of the jurisdictional requirements. This section describes pre-inspection and post-inspection activities applicable to all pressure-retaining items. Specific inspection requirements for pressure-retaining items are identified in RB-5000 for boilers, RB-6000 for pressure vessels and RB-7000 for piping.

All openings leading to external attachments, such as water column connections, low water fuel cut-off devices, openings in dry pipes, and openings to safety valves, should be examined to ensure they are free from obstruction.

RB-5525 MISCELLANEOUS

The piping to the water column should be carefully inspected to ensure that water cannot accumulate in the steam connection. The position of the water column should be checked to determine that the column is placed in accordance with ASME Code or other standard or equivalent requirements.

The gas side baffling should be inspected. The absence of the proper baffling or defective baffling can cause high temperatures and overheat portions of the boiler. The location and condition of combustion arches should be checked for evidence of flame impingement, which could result in overheating.

Any localization of heat caused by improper or defective installation or improper operation of firing equipment should be corrected before the boiler is returned to service.

The refractory supports and settings should be carefully examined, especially at points where the boiler structure comes near the setting walls or floor, to ensure that deposits of ash or soot will not bind the boiler and produce excessive strains on the structure due to the restriction of movement of the parts under operating conditions.

When tubes have been rerolled or replaced, they should be inspected for proper workmanship. Where tubes are readily accessible, they may have been over rolled. Conversely, when it is difficult to reach the tube ends they may have been under rolled.

Drums and headers should be inspected internally and externally for signs of leakage, corrosion, overheating, and erosion. Inspect blowdown piping and connections for expansion and flexibility. Check header seals for gasket leakage.

Soot blower mechanical gears, chains, pulleys, etc., should be checked for broken or worn parts. Inspect supply piping to the soot blowers for faulty supports, leakage, and expansion and contraction provisions. Check design for proper installation to allow for complete drainage of condensate, which may cause erosion.

Valves should be inspected on boiler feedwater, blowdown, drain, and steam systems for gland leakage, operability, tightness, handle, or stem damage, body defects and general corrosion.

RB-5526 GAGES

Ensure that the water level indicated is correct by having the gage tested as follows:

a. Close the lower gage glass valve, then open the drain cock and blow the glass clear.

b. Close the drain cock and open the lower gage glass valve. Water should return to the gage glass immediately.

c. Close the upper gage glass valve, then open the drain cock and allow the water to flow until it runs clean.

d. Close the drain cock and open the upper gage glass valve. Water should return to the gage glass immediately.

If the water return is sluggish, the test should be discontinued. A sluggish response could indicate an obstruction in the pipe connections to the boiler. Any leakage at these fittings should be promptly corrected to avoid damage to the fittings or a false waterline indication.

Each hot water boiler should be fitted with a temperature gage at or near the boiler outlet

RB-5529 RECORDS REVIEW

A review of the boiler log, records of maintenance and feedwater treatment should be made by the Inspector to ensure that regular and adequate tests have been made on the boiler and controls.

The owner or user should be consulted regarding repairs or alterations, if any, which have been made since the last inspection. Such repairs or alterations should be reviewed for compliance with the jurisdictional requirements, if applicable.

RB-5600 SPECIFIC INSPECTION REQUIREMENTS FOR BOILER TYPES

The following details are unique to specific type boilers and should be considered when performing inspections along with the general requirements as previously outlined.

RB-5601 WATERTUBE BOILERS

Typically constructed of drums, headers, and tubes, boilers of this type are used to produce steam or hot water commonly in large quantities. They range in size and pressure from small package units to extremely large field erected boilers with pressures in excess of 3000 psig (20 MPa gage). These boilers may be fired by many types of fuels such as wood, coal, gas, oil, trash, and black liquor.

There are many locations both internal and external where moisture and oxygen combine causing primary concern for corrosion. The fuels burned in this type of boiler may contain ash, which can form an abrasive grit in the flue gas stream. The abrasive action of the ash in high velocity flue gas can quickly erode boiler tubes. Their size and type of construction poses mechanical and thermal cyclic stresses.

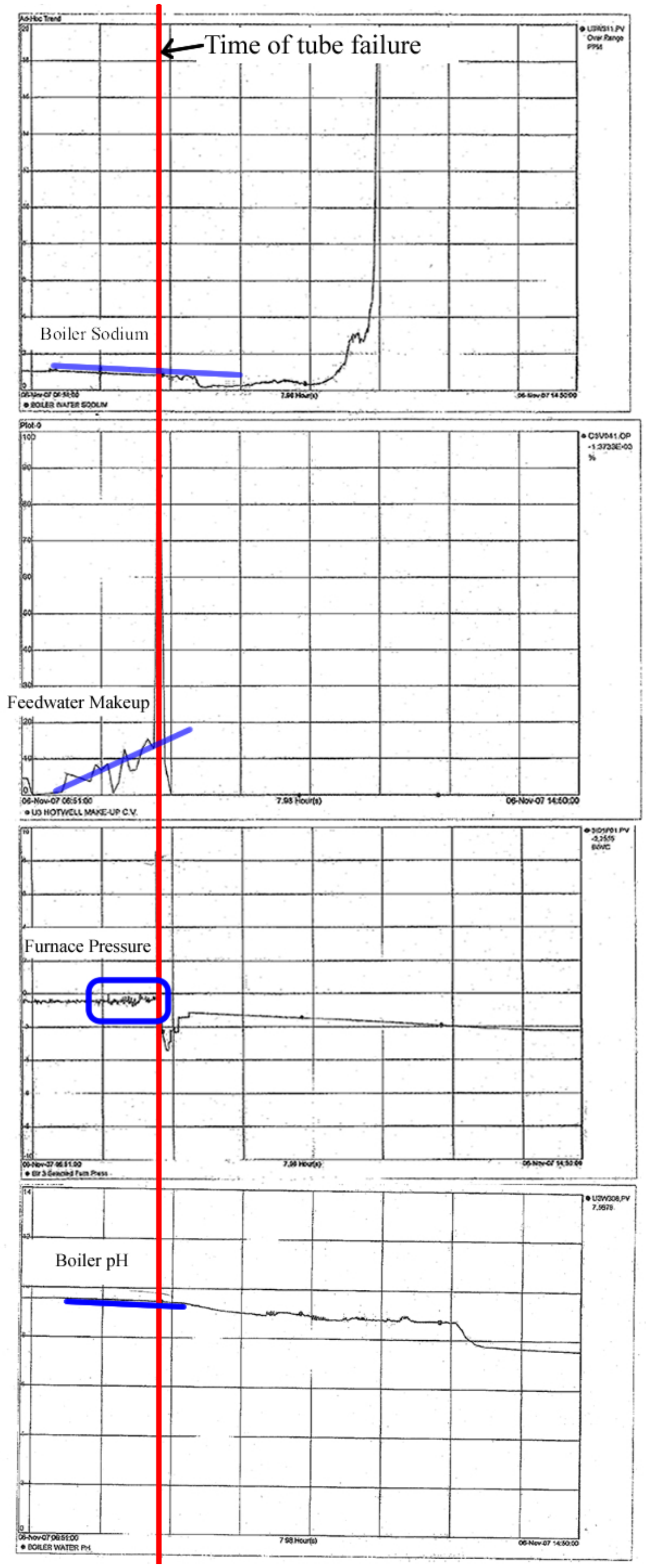
Unique parts associated with this type of construction such as casing, expansion supports, superheater, economizer, soot blowers, drums, headers, and tubes should be inspected carefully and thoroughly in accordance with RB-5500, as applicable.

RB-5602 BLACK LIQUOR (KRAFT OR SULFATE) RECOVERY BOILERS

Boilers of this type are used in the pulp and paper industry. Black liquor is a by-product of pulping processing. It contains organic and inorganic constituents and is concentrated from about 10% solids to at least 58% solids for firing in the recovery boilers. The organic material that is dissolved in the pulping process combusts and the spent pulping chemicals form a molten pool in the furnace. The molten material, or "smelt," drains from the furnace wall through smelt spouts into a smelt dissolving tank for recovery of the chemicals. Ultimately, the by-product of the recovery process is steam used for processing and power. Gas or oil auxilliary burners are used to start the self-sustaining black liquor combustion process and may be used to produce supplemental steam if sufficient liquor is not available.

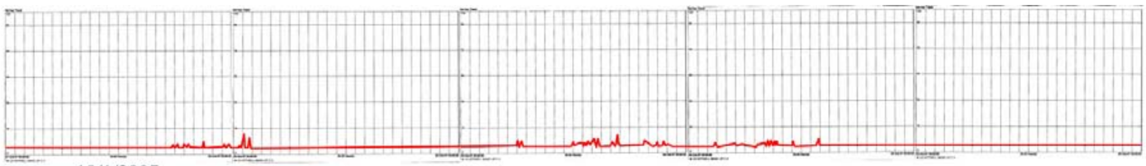
The recovery combustion process requires a reducing atmosphere near the furnace floor and an oxidizing atmosphere in the upper furnace for completion of combustion. Pressure parts within the furnace require protection from the reducing atmosphere and from sulfidation. The rate of corrosion within the furnace is temperature dependent. Boilers operating up to 900 psi (6 MPa) typically have plain carbon steel steam generating tubes with pin studs applied to the lower furnace to retain a protective layer of refractory or "frozen" smelt. Above 900 psi (6 MPa) the lower furnace tubes will typically have a special corrosion protection outer layer. The most common is a stainless steel clad "composite

Appendix 22



Time of tube failure
Ad-Hoc Trend
Boiler Sodium
7.98 Hour(s)
BOILER WATER SODIUM
Plot-0
Feedwater Makeup
06-Nov-07 06:51:00
7.98 Hour(s)
06-Nov-07 14:50:00
U3 HOTWELL MAKE-UP C.V.
Furnace Pressure
Boiler pH
7.98 Hour(s)
06-Nov-07 14:50:00
BOILER WATER PH

Appendix 23
Hot Well Makeup for Month of October 2007



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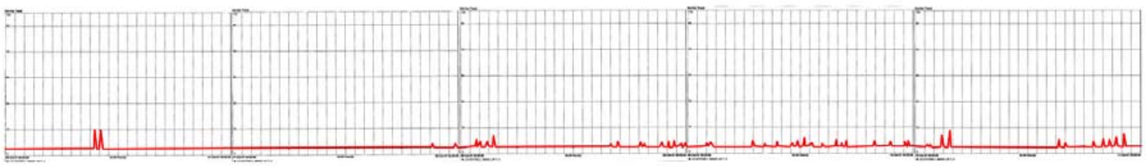

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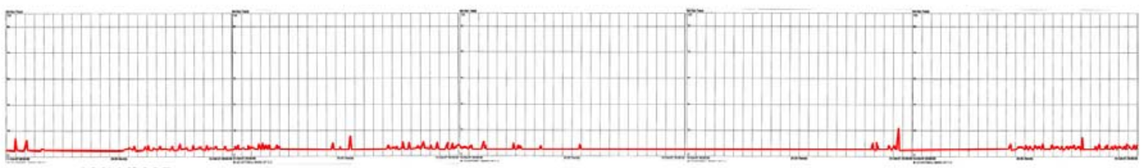

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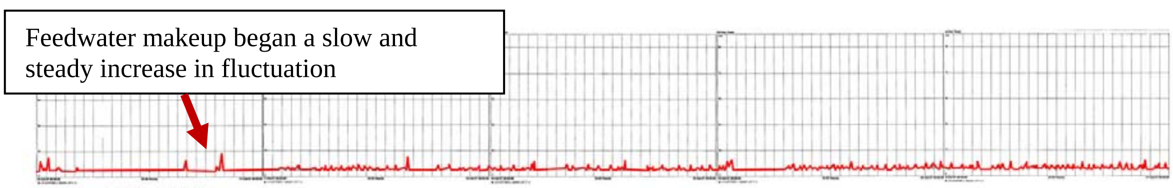

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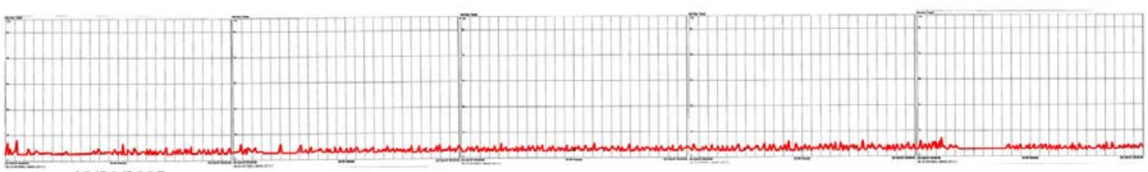

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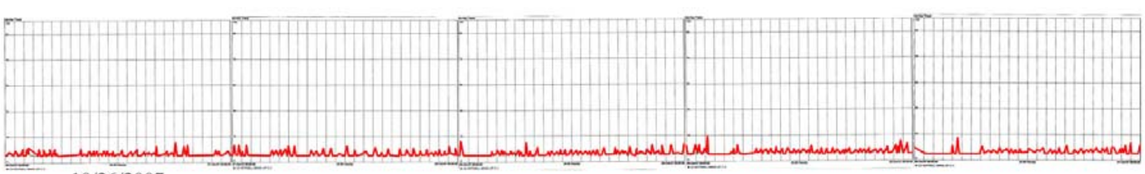

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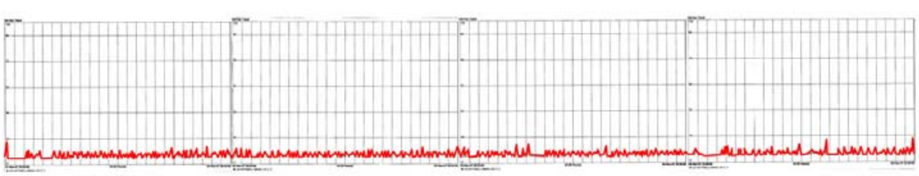

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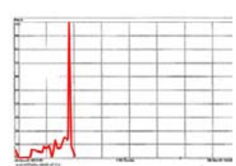
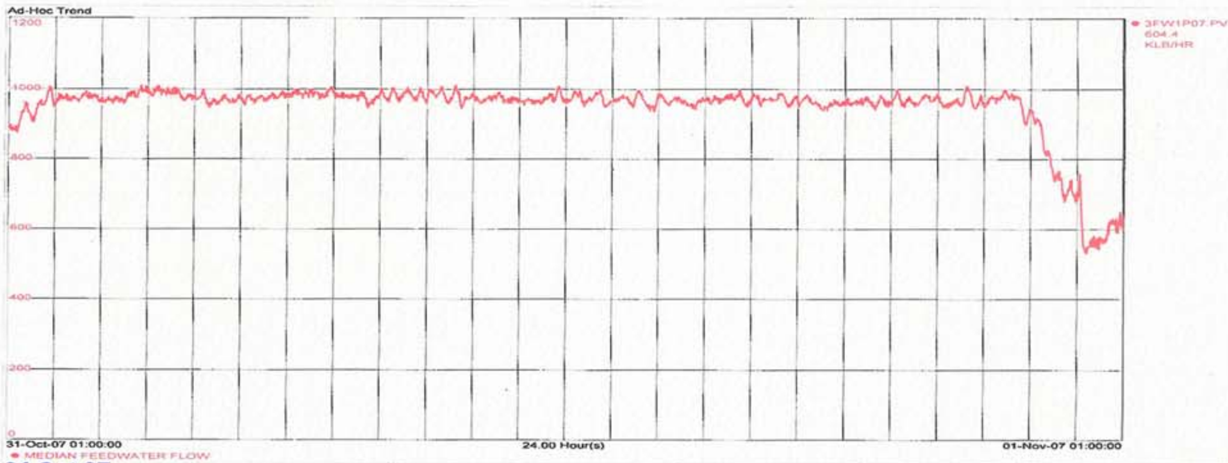


Appendix 24

Boiler #3 Median Feedwater Flow



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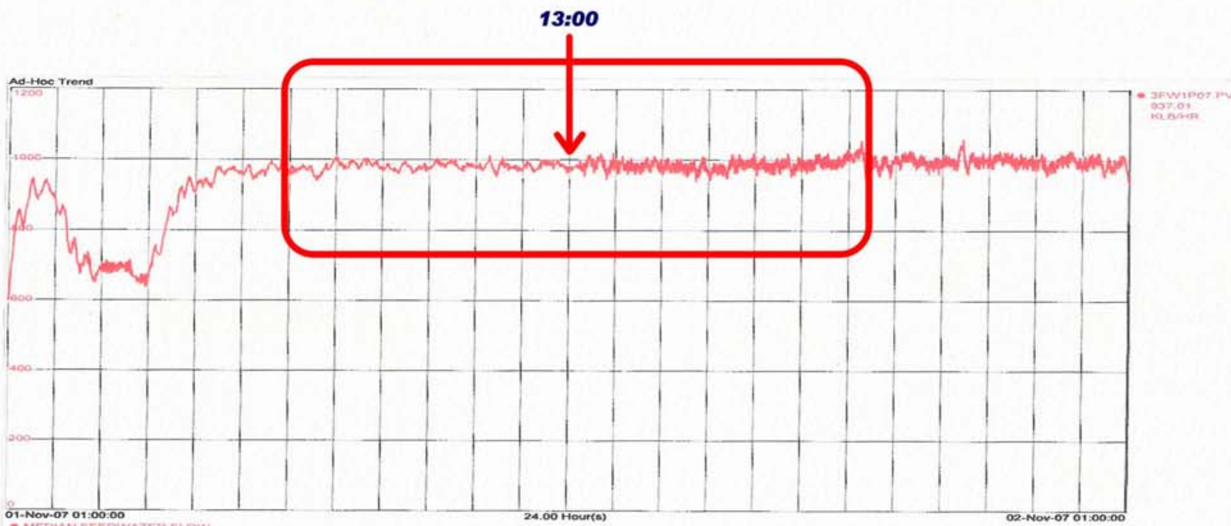

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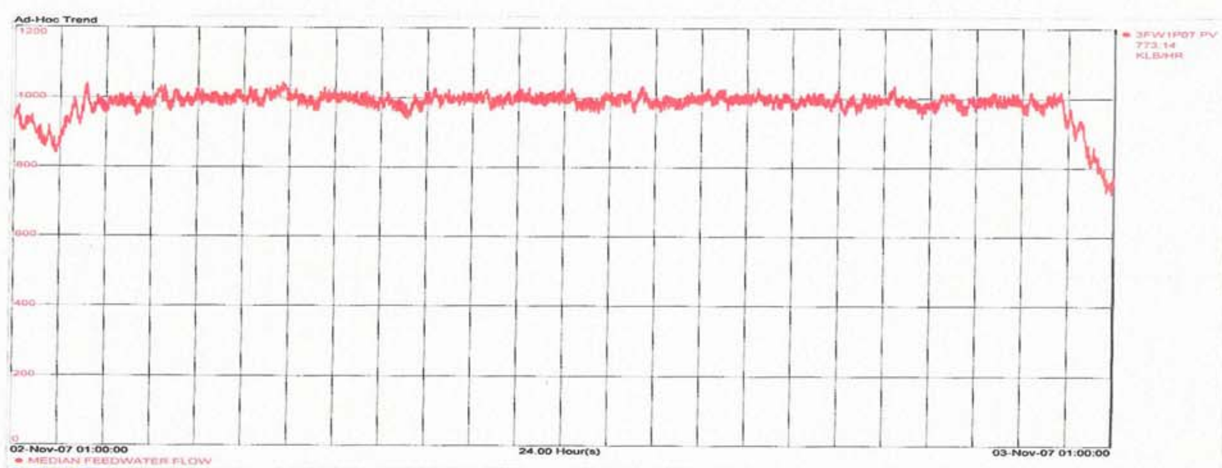
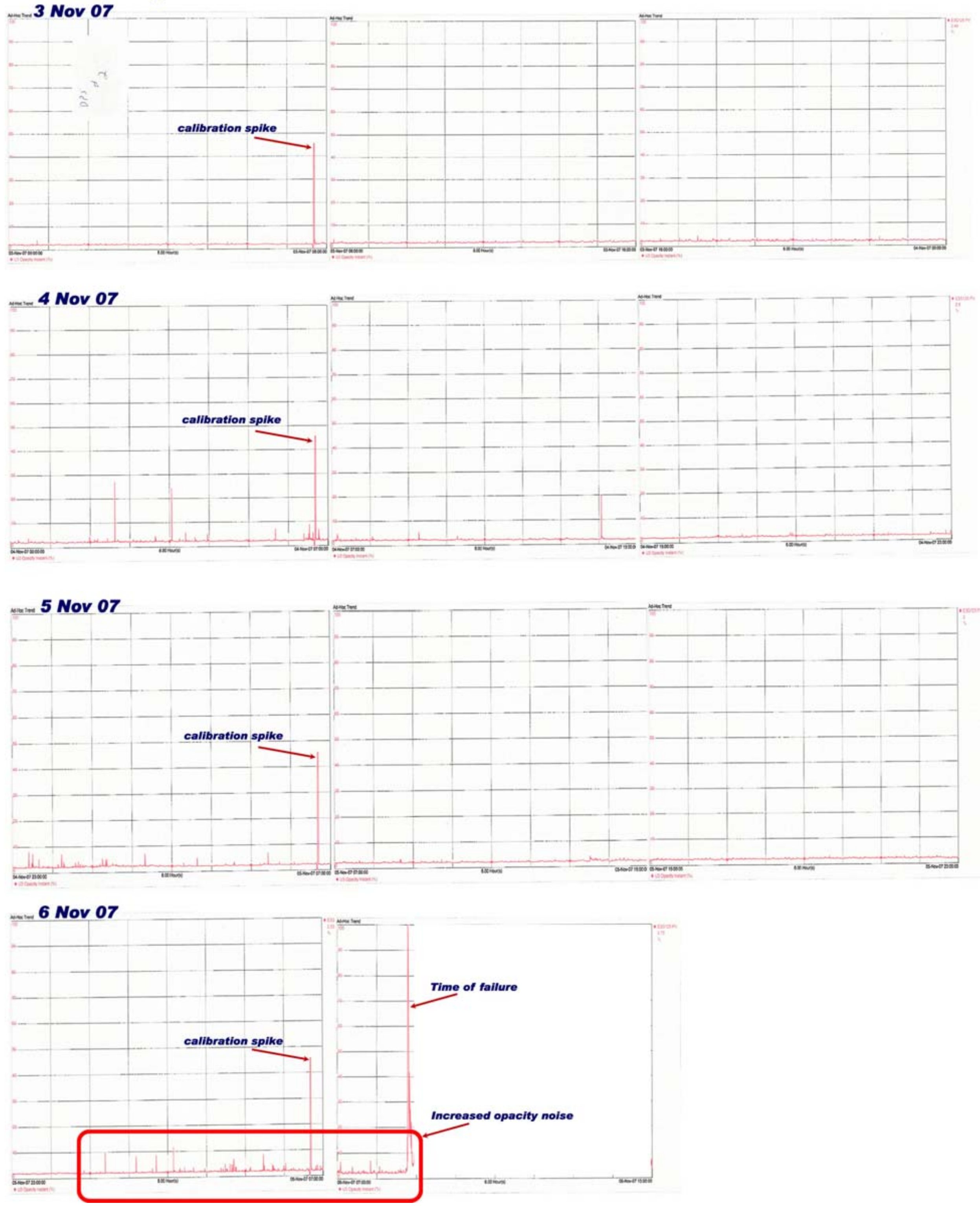


2 Nov 07

Appendix 25

Boiler 3 Opacity



Appendix 26

Dominion

Salem Harbor Station
24 Fort Ave
Salem, MA 01970

March 20, 2008

Mr. Mark Mooney
Commonwealth of Massachusetts
Department of Public safety
Chief of inspections
1 Ashburton Place, room 1301
Boston, MA 02108

Dear Mr Mooney,

In accordance with Chapter 522, Section 2.02 of the Code of Massachusetts Regulations, I Steven A. Dulong [redacted] First Class Engineers license #038618 am writing to notify the Department of Public Safety that I am leaving the position of engineer in charge of the Dominion Energy, Salem Harbor Power Station 24 Fort Ave., Salem, MA, effective March 20, 2008.

Sincerely,

Steven A Dulong

Steven A. Dulong

Appendix 27

SOOT BLOWING (Cont'd)

When permanent soot blowers are installed, care must be taken to see that the nozzles are maintained in their proper positions relative to the boiler tubes. If the nozzles become displaced in such manner that there is direct impingement of steam on the tubes, erosion of the metal will result. In operating soot blowers or using a steam lance, no portion of the heating surface should be blown steadily for too long a period, or similar erosion will occur.

With fuels having a tendency toward the formation of slag on the boiler or superheater surfaces adjacent to the furnace, slag-cleaning doors or blowers which are installed should be used at such intervals as the draft loss and exit gas temperatures indicate is necessary for commercial efficiency.

SHUTTING DOWN

Boiler units should be taken out of service at regular intervals for internal inspection, cleaning, and repair.

In taking a boiler out of service, the fuel-burning and preparation equipment, together with the draft apparatus, should be shut down in accordance with the instructions for the type of firing system used. Particular attention should be given to the condition in which the fuel equipment is left and the method of arriving at this condition, from the standpoint of temperature and cleanliness, in order to avoid the possibility of damage, during or subsequent to the shutting down because of overheating or an explosion.

After the firing equipment and fans are out of service, the dampers, including the superheater and superheater by-pass dampers when provided, should be closed in order to permit the unit to cool as slowly and uniformly as possible. When the boiler no longer requires any feed and the non-return steam valve has closed, the main steam stop valve should be closed and, in the case of economizer installations provided with recirculating connections, the valve in the economizer recirculator should be opened. The pressure should be allowed to drop naturally, without the aid of any open vents or other intentional taking of steam from the unit in order to increase the rate of decreasing the steam pressure. The superheater drains, however, should be opened sufficiently to keep all condensate out of headers. Hastening the cooling of the furnace by allowing large quantities of cool air to pass through the setting tends towards brickwork difficulties and unnecessary stresses in the pressure parts.

The use of a moderate amount of induced or natural draft after the furnace brickwork has lost its color is permissible.

When the steam pressure has dropped to about 25 pounds per square inch, the steam drum vent valve should be opened to prevent the formation of a vacuum within the boiler by total condensation of steam. A vacuum within the unit may cause future leakage of gasketed joints.

In the case of large high-pressure boilers the foregoing procedure requires such a long period of time that other methods of shutting down, using thermocouples distributed over the pressure parts of the unit to establish the allowable rate of cooling, become desirable in many cases. Such alternative procedure should be thoroughly discussed with the boiler manufacturer before being used.

The boiler should not be emptied until the furnace has cooled to a temperature at which one can enter and remain in the furnace. External cleaning of the heating

BRINGING BOILER TO PRESSURE (Cont'd)

such jobs, it is desirable to flood the drum before starting and high level gage glasses are being used by some plants to indicate the water level to permit flooding the drum with safety. When the top of the drum exceeds 175 F the boiler can be blown down to normal level. The thermocouple located 24 inches from the top of the drum can also be used as an indicator of drum level as there will be a sharp rise in temperature of this couple as water level approaches the top of the drum. When using this thermocouple as a guide, the unit should be fired until the bottom of the drum is about 175 F; shut off the fire, fill the drum to the top, using the temperature indicated by the thermocouple located 24 inches from the top of the drum as a warning for reducing the rate of feeding water and keep the drum filled until the temperature of the top of the drum approaches 150 F; blow down to normal water level and then fire up as mentioned above. Either of these two procedures permits adherence to the fundamental principle that no boiler is to be fired unless the water level is showing in the gage glass.

QUICK SHUTDOWN

The most effective way to cool down large boilers uniformly and quickly is to gradually reduce the pressure and the load on the unit, bringing the pressure down to the minimum value possible that plant conditions will permit as the load is reduced. This leaves all pressure parts at a uniform reduced temperature when firing is stopped. If the above is not possible, then extinguish the fires and allow the pressure to drop naturally. The forced-draft fans can also be used very effectively in assisting to speed the cooling down of large boilers. Whichever method is used to cool the boiler down, do not permit the drum temperature difference to exceed the cooling cycle curve in Fig. 1.

The simplest way to keep the temperature differential within limits is to: permit the pressure to drop until the temperature differential reaches the limit on cooling curve Fig. 1, extinguish the fires; raise the water level until the temperature at the very top of the drum drops sufficiently to show that the drum is full, or water level is noted in the high level glass if such a gage glass is available. Shut off the water, and, with the water level at the top of the drum and the fires shut off, allow the boiler to continue to cool down. When the temperature differential again reaches the limit, repeat the procedure of injecting feedwater. The quantities of water injected, subsequent to the first raising of the water level, will be in proportion to the shrinkage of cooling and, accordingly, will be quite small. In raising the water level to the top of the drum, it is important to keep water from going over into the superheater.

During the shutting-down period, the drum should be vented to remove any steam which tends to collect at the top of the drum. If the venting obtained by the normal handling of the superheater drains does not provide sufficient venting, the amount of draining or venting may be increased.

When the pressure has reached zero, the unit may be filled and hydrostatically tested or it may be drained, provided it has cooled sufficiently for a man to enter and remain in the furnace.

FORCED SHUTDOWN

Handling of the unit on forced shutdown refer to Operating Instruction "Protection of Boiler Drums" 1K-1a page 3.

Appendix 29

THE BABCOCK & WILCOX COMPANY
NEW YORK, N. Y.

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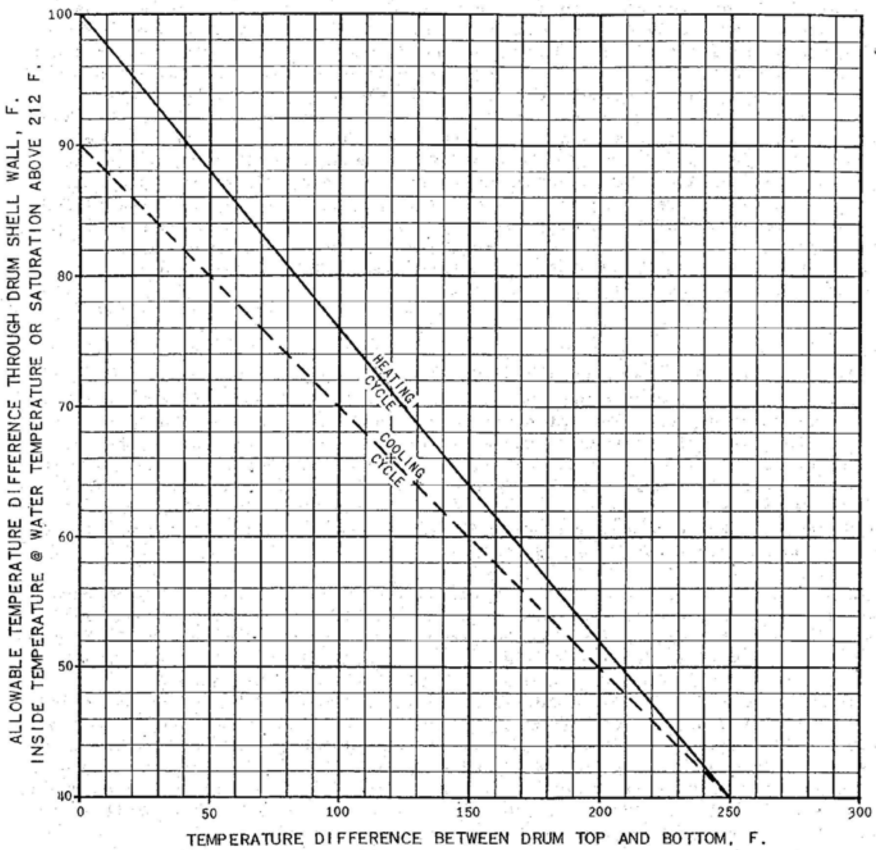

QUICK STARTUP OF BOILERS
ALLOWABLE TEMPERATURE DIFFERENTIALS
IN BOILER DRUMS UP TO 6-1/2 IN. THICK SHELL

Fig. 1

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G.3 Pulverized-fuel furnaces should be operated by making changes gradually and by avoiding extremes. Even though a wrong condition exists, such as loss of ignition, a quick change in either re-igniting the fuel or in changing the rate of air flow should be avoided and all changes should be made with full knowledge of existing conditions.

H. REGULAR SHUTDOWN

When it is desired to shut down a direct-fired pulverized-fuel fired unit and the unit is coming off the line in the normal way, proceed as follows:

H.1 Open the tempering air valve to the pulverizer and close the hot air control valve simultaneously to maintain the same air flow through the pulverizer. Continue operation for about five minutes or until the pulverized-fuel and air mixture leaving the pulverizer is approximately 100 F. It is recommended that a lighter be placed in service in the last pulverized-fuel burner coming off.

H.2 Stop the raw-fuel feeder.

H.3 Stop the pulverizer when empty. When the flame (at the burners in connection with the pulverizer being shut down) goes out, the pulverizer may be considered empty for shutting down purposes. The operator will usually notice a more metallic sound being emitted from the pulverizer.

H.4 Stop the primary air fan and close the fuel-air valves in the burner lines, and the primary air control damper.

H.5 Stop the forced-draft fan and close the forced-draft dampers and the individual burner secondary air dampers.

H.6 Stop the induced-draft fan and close the induced-draft damper.

J. EMERGENCY SHUTDOWN

When an emergency shut down is necessary and there is sufficient time to permit clearing the pulverizer, proceed as follows:

J.1 Stop the raw-fuel feeder.

J.2 Stop the pulverizer when a decided metallic sound is noted.

J.3 Stop the primary air fan and close the primary air control damper.

J.4 Close the hot-air control valve and the fuel-air valves in the burner lines.

J.5 Stop the forced-draft fan and close the forced-draft dampers and the individual burner secondary air dampers.

J.6 Stop the induced-draft fan and close the induced-draft damper.

K. FORCED SHUTDOWN

In case a shutdown of the pulverizer occurs and the pulverizer has not run empty, the equipment should again be put into service within 30 minutes after the shutdown according to the method described under "E. REGULAR STARTING". It should be remembered that in this case, the pulverizer already has a supply of partly

INSPECTION AND CLEANING - EXTERNAL (Cont'd)

before the unit is put back in service, so that the heating up of the unit will thoroughly dry the water out of all crevices, pockets, porous refractories, or other places where it may have collected and may cause corrosion if allowed to remain. If water or steam washing is done at some other time during an outage the unit should be immediately fired sufficiently to dry it thoroughly. Where the sulphur content of the fuel is high it is advisable, before washing, to neutralize the acid condition of the soot by wetting down the surfaces exposed to the gases with an alkali solution.

The inspection should also include the fuel-burning equipment, especially those parts which are not accessible when the unit is in service, and repairs, or replacements should be made to permit proper functioning of the equipment as well as to reduce the possibility of interruptions during subsequent operation.

A check of all soot blowers should be a regular maintenance item during regular scheduled boiler outages. Tubes in zones of soot blowers should be inspected closely for any signs of metal loss due to fly ash or steam cutting. Direct impingement of steam on tubes may result from the shifting of the soot blower element, or from growth of blower elements which may move the nozzles out of register with the spaces between the tubes. Polishing of tubes can result from high soot blower pressure, especially on coal-fired jobs where the fly ash is highly abrasive. In this case, a reduction of blowing pressure should be made, either by adjustment of the orifice in adjustable orifice head blowers, or by installation of smaller orifice plates after the soot blower head flanges, depending on the type of soot blower head on the unit. In hot locations the steam nozzles of the elements may shrink; they should therefore be checked for correct inside diameter, and enlarged if necessary.

SPECIAL INSPECTION - STATE OR INSURANCE

In addition to routine operating inspections, a thorough inspection from the viewpoint of safety should be made yearly at the time of the visit of the Insurance Inspector or State Inspector. This should include a most careful search for evidence of internal and external corrosion, leakage of seams, leakage of expanded, screwed or welded joints, evidence of overheating, and the condition of the structural supports. It may be necessary to remove small sections of brickwork or casing to make such inspection complete, but it should be borne in mind that the parts which are most slighted, due to soot accumulation or difficulty of access, may be the very parts in which trouble will develop.

IDLE BOILERS

Boilers to be held out of service must be carefully prepared for the idle period and closely watched during the outage to reduce the possibility of corrosion to the minimum.

PROTECTION OF INTERNAL SURFACES - DRY STORAGE

When it is known that a boiler will be stored for a considerable length of time and allowance can be made for a brief period of preparation for demanded service, the dry storage method is recommended. In this method, the unit is emptied, thoroughly cleaned internally and externally, dried, and then closed up tight to exclude both moisture and air. Trays of lime, silica gel, or other moisture absorbent may be placed in the drums to absorb the moisture in the air trapped by the closing up of the boiler. The pans should not be more than three

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- Ultrasonic Thickness Inspection–UTT should be performed in sootblower lanes and any areas identified by visual examination as potential sites of excessive wall loss.
- Internal Oxide Thickness Inspection–Internal oxide thickness measurements should be taken and remaining creep rupture lives calculated for the alloy tube materials in the hottest regions of the superheater and reheater. A large number of inspection locations should be taken on the initial inspection. Ideally the alloy tube material (SA213T11, SA 213T22) is tested at location where metal temperatures are greatest. A good location is immediately upstream at transition welds to the next grade material. For example, a good location to test T11 material is immediately upstream of the transition to T22 material. In general, the locations are selected based on hottest location but must also consider accessibility. Future inspection locations can be reduced based on results of the initial inspection, history, tube material, dimensional changes, and visual inspections.

Water-cooled Water-cooled tubes include those of the economizer, boiler bank and furnace. The convection pass sidewall and screen tubes may also be water-cooled . These tubes operate at or below saturation temperature and are not subject to significant creep. Modern boilers in electric utilities and many industrial plants operate at high pressures. Because these boilers are not tolerant of water-side deposits, they must be chemically cleaned periodically, which results in some tube material loss. Proper water chemistry control will limit tube inside surface material loss due to ongoing operations and cleaning. The importance of maintaining water quality and keeping ID tube surfaces clean cannot be overly stressed. Extensive damage of waterwall circuits has often resulted from excessive deposition that can lead to aggressive corrosion and hydrogen damage. On cycling boilers a serious problem has also been corrosion-fatigue damage at lower furnace attachment points such as buckstays and windbox attachments. Corrosion fatigue leads to ID initiated cracking that is very difficult to detect by nondestructive methods. Research sponsored by EPRI is currently ongoing to address this NDE need.[2]

Externally, water-cooled tubes are subject to damage. Erosion is most likely to occur on tube surfaces in the boiler or economizer bank from sootblowing or ash particle impingement. Erosion of waterwall tubes can also result from sootblower operation. Corrosion of the water-cooled tubes can result from reducing atmospheres associated with mal-distributed burner air or result from staged combustion on low N0x burner installations. Some types of coal ash can promote corrosion of waterwall tubes as well.

Steam- and/or Water-Cooled–External to Setting Of special concern are some unique problems that have led to failures of tubing that is outside the boiler settings. These type failures have a potential for exposing plant personnel to safety hazards. Examples are supply or riser tubes on units that have had water chemistry control problems when using chelants. Excessive chelant can attack tubing aggressively and lead to thinning and failures. More recently, corrosion-fatigue has been identified on older units (>30 years operation) as the root cause mechanism of riser tube failure in the penthouse. In both instances, whether chelant attack or corrosion-fatigue, the failures tended to be catastrophic with a large piece of tube rupturing.

A typical condition assessment inspection of water-cooled tubes would consist of the following:

- Visual Inspection – A visual inspection will generally find severe erosion, corrosion and thermal shocking, and numerous other problems such as damage from slag falls, local overheat, swelling, etc. Based on the visual inspection, additional methods may be recommended.
- Ultrasonic Thickness Inspection – UTT is by far the most often used inspection method on water-cooled tubes. Initially a comprehensive thickness inspection should be performed. This results in baseline data that may be compared to future, limited scope inspections.
- EMATS Based Inspection – This form of inspection is used to locate tube ID under deposit corrosion, pitting or other tube ID problems such as hydrogen damage. Systems are available for tube thickness mapping[3] and are in development for detection of corrosion-fatigue damage.

Tube Life Assessment

For alloy superheater tubes, life assessment methodologies are well established.[4] Tube remaining life can be determined using creep rupture properties of materials and life fraction analysis methods. A caution when using these life prediction methods is to use the data as a compliment to other data such as tube analysis and failure history. Material creep properties have wide variation from heat to heat. Remaining life predictions should therefore provide a guideline to help establish trends relative to failures and time of replacement and should not be used as an exact life calculation.

For low temperature tubing, life prediction is done by comparing wall loss trends to a predetermined flag or replacement criteria. As a general guideline B&W recommends a flag of 70% original specified wall thickness for water-cooled tubes. For damage mechanisms such as hydrogen damage, cracking or corrosion-fatigue, no attempt is made to predict life – the goal for these tubes is identification of damaged tubes with recommended replacement.

Headers

Headers and their associated problems can be grouped according to operating temperature. High temperature steam-carrying headers are a major concern because they have a finite creep life and their replacement cost is high. Lower temperature water- and steam-cooled headers are not susceptible to creep but may be damaged by corrosion, erosion, or severe thermal stresses.

High temperature The high temperature headers are the superheater and reheater outlets which operate at a bulk temperature of 900F (482C) or higher. Headers operating at high temperature experience creep under normal conditions. In addition to material degradation resulting from creep, high temperature headers can experience thermal and mechanical fatigue. Creep stresses in combination with thermal fatigue stress lead to failure much sooner than those resulting from creep alone. There are three factors influencing creep fatigue in superheater high temperature headers: combustion, steam flow and boiler load. Most manufacturers design a boiler with burners arranged in the front and/or rear walls. Heat distribution within the boiler is not uniform: burner inputs can vary, air distribution is not uniform, and slagging and fouling can occur. The net effect of these combustion parameters is variations in heat input to individual superheater and reheater tubes. When combined with steam flow differences between tubes within a bank, significant variations in steam temperature entering the header can

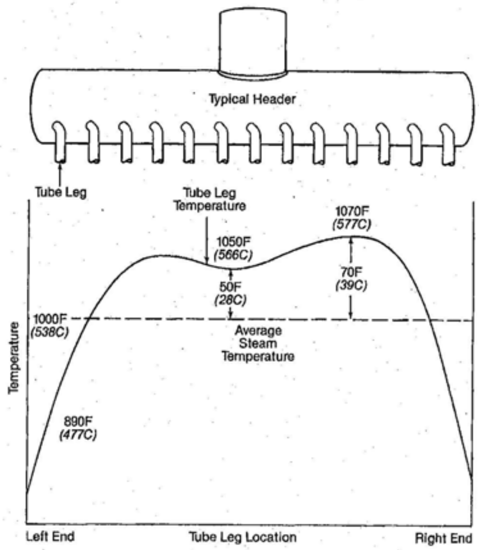

Fig. 2 Steam temperature variation in a header.

occur (Fig. 2). Changes in boiler load further aggravate the temperature difference between the individual tube legs and the bulk header. As boiler load increases, the firing rate must increase to maintain pressure. During this transient, the boiler is temporarily over-fired to compensate for the increasing steam flow and decreasing pressure. During load decreases, the firing rate decreases slightly faster than steam flow in the superheater with a resulting decrease in tube outlet temperature relative to that of the bulk header. As a consequence of these temperature gradients, the header experiences localized stresses much greater than those associated with steam pressure (Fig. 3) and can result in large ligament cracks (Fig. 4).

In addition to the effects of temperature variations, the external stresses associated with header expansion and piping loads must be evaluated. Header expansion can cause damage on cycling units resulting in fatigue cracks at support attachments, torque plates, and tube stub to header welds. Steam piping flexibility can cause excessive loads to be transmitted to the header outlet nozzle. These stresses result in externally initiated cracks at the outlet nozzle to header saddle weld.

Condition assessment of high temperature headers should include a combination of non-destructive examination (NDE) techniques that are targeted at the welds where cracks are most likely to develop:

- Visual Inspection
- Wet Fluorescent Magnetic Particle Inspection–All major header welds, including the outlet nozzle, torque plates, support lugs and plates, circumferential girth welds should be WFMT inspected. Initially, 100% of the tube stub to header welds should be WFMT inspected. After the baseline WFMT inspection, future WFMT inspections may be limited to 10-25% of the tube stub to header welds.
- Ultrasonic angle beam shear wave examination of major welds–This is particularly important if the header has any long seam welds. In general, B&W follows EPRI-established guidelines for examination of these welds.[5]
- Metallurgical Replication–To examine the header for creep damage, metallographic replication should be performed. Typically, between 6-12 replicas are taken on the header tube stubs, header circumferential or longitudinal pipe welds, and nozzle to header welds. Locations for replicas are typically in the areas of highest temperature or stress.
- Ligament and Bore Hole Inspection–The major cause of header end-of-life in the US is creep fatigue. This results in ligament and bore hole cracking. A total of two to three of the hottest or highest stressed areas should be inspected. B&W strongly believes that effective bore hole examination must be preceded by removal of the high temperature oxide. It is important that the base metal of the header be examined for cracking (Fig. 5). B&W developed a unique process for this inspection which is called the Hone & Glow® exam.

Low temperature The low temperature headers are those operating at temperatures below which creep is a consideration. These include waterwall headers, economizer inlet and outlet

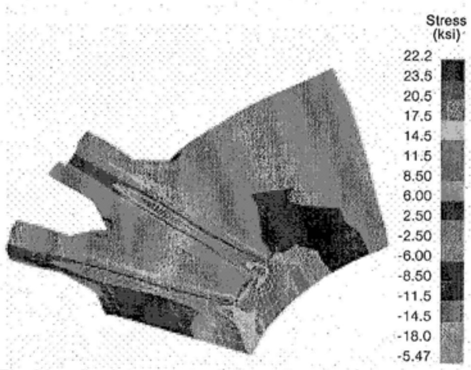

Fig. 3 Localized stresses due to thermal gradients.

Fig. 4 Large ligament cracks on header ID.

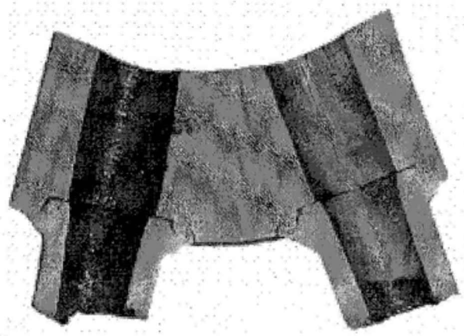

Fig. 5 Header bore hole cracking.

headers, and superheater inlet and intermediate headers. Any damage to the low temperature headers is generally caused by corrosion or, in some instances, erosion or thermal fatigue.

Waterwall headers, found in most electric utility and industrial power generation boilers, are located outside the hostile environment of the combustion zone. An exception is the economizer inlet header; this header is often located in the gas stream and is subject to unique problems associated with cycling. Boilers that are held overnight in a hot standby condition without firing can experience severe damage to the economizer inlet header in a very short time. This damage is typically caused by thermal shock.

The magnitude of the thermal shock is a function of the temperature differential between the unheated feedwater and the inlet header. It is also a function of water flow, which is usually large because the feedwater piping/valve train is sized for rated boiler capacity. The thermal shock is worse near the header feedwater inlet and rapidly decreases as flow passes into the header and tubes. Economizer inlet headers have also experienced damage associated with flow-accelerated corrosion. In general the primary concern with most of the low temperature headers is internal and external corrosion, especially during out of service periods.

Typical inspections of these headers consist of:

- Visual Inspection
- Wet Fluorescent Magnetic Particle–A WFMT inspection should be performed on welded attachments, handhole plugs, header end plate welds, and 10% of tube to header welds.
- Video Probe Inspection–An internal visual inspection can be performed to locate internal problems.
- UTT–Should visual inspection reveal areas of wall loss from either corrosion or erosion, then ultrasonic thickness data may be taken to assess header thickness.

Header Life Assessment

For low temperature headers, the life is not necessarily finite in the normal life spans of the boiler. Replacement of low temperature headers will result from unique damage such as thermal fatigue and cracking. Instances of damage to low temperature headers are very much dependent on the specific plant and operating history. Low temperature headers are more likely to be replaced as part of unit upgrades or as tandem replacement with other components such as wall panels.

As noted previously, high temperature headers on older units were typically made of SA335P22 alloys and will eventually need to be replaced due to reaching their end-of-life. Accurate quantification of header life is difficult since damage is attributed to creep fatigue and is driven by locally high stresses, temperatures and cycles that are not readily measured. Software tools have been developed under projects sponsored by EPRI. The software BLESS[6] which resulted from this work provides for prediction of crack initiation as well as crack growth to predict or quantify life. The difficulty is in accurately defining operating parameters and material properties. Material sampling and testing may be necessary to fully implement the analysis for best results. In general, based on B&W experience, analytical programs such as BLESS have been used as a tool along with other data to help make short term decisions for headers that have already experienced significant cracking, i.e. BLESS can be invaluable to help make a run/repair decision. For most projects, an attempt is not made to quantify remaining life by analysis. From empirical experience and re-inspection programs, sufficient data is normally available to make decisions for life extension projects. Economic analysis of risk and unavailability are a key part of this process.

Attemperators

The attemperator, or desuperheater, is located in the piping of the superheater and is used for steam temperature control. The spray attemperator is the most common type used. In the spray unit, high quality water is sprayed directly into the superheated steam flow where it vaporizes to cool the steam. The attemperator is typically located in the piping between the primary superheater outlet header and the secondary superheater inlet header. Steam exiting the primary header at temperatures of 800 to 900F (427 to 482C) enters the attemperator, where relatively cool water [300F (149C)] is sprayed into the steam and reduces the temperature to the inlet of the secondary superheater. Because of the large temperature difference between the steam and spray water, parts of the attemperator experience thermal shock each time it is used. Over a period of years this leads to thermal fatigue and eventual failure.

Condition assessment of the attemperator requires removal of the spray nozzle assembly. The thermal stresses occurring in the attemperator are most damaging at welds, which act as stress concentrators. The spray head and welds on the nozzle assembly are examined visually and by liquid penetrant PT to ensure there are no cracks. With the spray head removed the liner can be examined with a video or fiber optic probe. For larger attemperators, it may be necessary to remove radiograph plugs before and after the attemperator to better view the critical liner welds.

Attemperator Life Assessment

Spray flow attemperators are critical in the condition assessment program since they are in the closed loop of the superheater. Failures in the attemperator can lead to collateral damage in the superheater leading to tube failures. If left undetected over a long period of time, attemperator failures have the potential to lead to piping failure as a result of thermal fatigue. In general, the attemperator is treated as a preventive maintenance item. They should be periodically inspected following 10 years operation. It is prudent to maintain spares on hand for eventual replacement of the spray head assembly.