NUREG-1063

Steam Generator Operating Experience Update 1982-1983

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

L. Frank

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Manuscript Completed: December 1983
Date Published: June 1984

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ABSTRACT

This report is a continuation of earlier reports by the staff addressing pressurized water reactor steam generator operating experience. NUREG-0886, "Steam Generator Tube Experience," published in February 1982 summarized experience in domestic and foreign plants through December 1981. This report summarizes steam generator operating experience in domestic plants for the years 1982 and 1983. Included are new problems encountered with secondary-side loose parts, sulfur-induced stress-assisted corrosion cracking, and flow-induced vibrational wear in the new preheater design steam generators. The status of Unresolved Safety Issues A3, A4, and A5 is also discussed.

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF TABLES

STEAM GENERATOR OPERATING EXPERIENCE UPDATE, 1982-1983

1 INTRODUCTION

In January 1979, NUREG-0523, "Summary of Operating Experience With Recirculating Steam Generators," was published. This report focused on the problems associated with the operation of Westinghouse (W) and Combustion Engineering (CE) steam generators. In March 1980, NUREG-0571, "Summary of Tube Integrity Operating Experience With Once-Through Steam Generators," was published; it discussed operating problems associated with Babcock & Wilcox (B&W) steam generators. NUREG-0886, "Steam Generator Tube Experience," published in February 1982, contained a summary of past and updated operating experience of all pressurized water reactor (PWR) steam generators through December 1981. This report highlights new operational events in domestic plants relating to steam generator integrity that occurred in 1982 and 1983 and also updates inspection results reported during this period.

Major new findings were secondary-side damage to tubes as a result of foreign objects, accelerated wear of tubes in new preheater design steam generators, and widespread corrosion attack resulting from sulfur ingress on the primary side of a steam generator.

Degradation mechanisms previously described for recirculating and once-through steam generators (OTSGs) were still active during 1982 and 1983, although at a somewhat diminished rate, as tube sleeving and steam generator replacements took place.

2 STEAM GENERATOR DESIGNS

Three manufacturers supply Inconel 600 tubed steam generators for pressurized water reactor nuclear plants. These generators are briefly described below (additional details are given in NUREG-0523 and NUREG-0571).

2.1 Westinghouse

Westinghouse (W) manufactures two general types of vertical recirculating U-bend tubed steam generators; those predominately in use are of the feedring design designated Models 27, 33, 44, and 51, and the newer preheater design designated Models D2, D3, D4, D5, and E, which are intended to increase the plant thermal efficiency. Models D2 and D3 are split-flow preheaters; Models D4, D5, and E are counterflow preheaters. Replacement steam generators (e.g., 44s and 51s) use Model F steam generator material and design features that improve anticorrosion performance and are designated 44F or 51F.

2.2 Combustion Engineering

Combustion Engineering (CE) manufactures a standard vertical recirculating U-bend tubed steam generator with different models based on the number of tubes required by the thermal output of the plant. The generator at the Palisades Nuclear Plant has drilled hole support plates for the lower six tube supports instead of egg crate supports in use at other CE plants.

2.3 Babcock & Wilcox

The Babcock & Wilcox (B&W) steam generators are vertical, straight-tube-and-shell, once-through heat exchangers.

3 DEGRADATION MECHANISMS

Degradation mechanisms in operating steam generators have been well documented in the previously cited reports and are briefly summarized below. Included are new degradation mechanisms that were reported during the 1982-1983 period.

3.1 Corrosion-Induced Degradation

Wastage or thinning and intergranular stress corrosion cracking of steam generator tubes in recirculating steam generators were early manifestations of corrosion-induced degradation resulting from upset phosphate water chemistry. Wastage or thinning occurred when sodium-to-phosphate ratios were less than 2.3; cracking occurred when the ratios were greater than 2.6.

Intergranular attack (IGA) of steam generator tubes has occurred at crevice locations in plants where a combination of caustic material from phosphate residues and condenser inleakage impurities act synergistically.

Both denting of steam generator tubes caused by corrosion of the carbon steel support plates and pitting of steam generator tubes are the result of excessive condenser water inleakage, oxygen inleakage, and the combination acting on copper alloy condenser and feed train materials which give rise to local acidic chloride conditions involving copper and chloride ions. Stress corrosion cracking of the inside diameter (primary water side) of steam generator tubes has occurred at locations of very high stress, that is, near or above yield. Inside-diameter cracking has occurred at dent locations at the point of highest strain. Inside-diameter cracking has also occurred in tight U-bend tubes at two locations: (1) at the U-bend apex because of an increase in hoop strain resulting from inward motion of the tube legs at the uppermost support plate and (2) at the tangent point between the straight portion and the end of the bend because of high residual manufacturing stresses.

During this reporting period inside-diameter stress corrosion cracking, which was observed in an OTSG in November 1981, was found to be caused by a combination of sulfur inleakage from the sodium thiosulfate in the reactor building spray system and oxygen introduced during hot functional tests.

3.2 Wear-Induced Degradation

Tube wear results from the mechanical abrasion of the tube surface. It has been observed at antivibration bar intersections, at baffle plate locations in preheater sections, and at locations where the tube came into contact with loose parts.

The preheater tube wear was due to tube vibrations in high flow areas of Westinghouse Models D2/D3 and D4/D5/E preheat steam generators.

In the case where loose parts induced wear, a foreign object impacted and severed a previously plugged tube. The severed tube, acting as a loose part, subsequently wore against an unplugged tube producing a long wear scar that ultimately led to rupture.

3.3 Fatigue

In OTSGs, tubes adjacent to the open lanes have failed near their junction with the upper tubesheet. Failure has been attributed to fatigue from flow-induced vibration at corrosion-initiated sites.

3.4 Girth Welding Cracking

Low cycle corrosion fatigue cracks possibly initiated at pit sites in the circumferential weld joining the transition cone to the upper shell of a Westinghouse steam generator at one plant led to a small leak. It is believed that condenser water inleakage, oxygen inleakage, and copper corrosion products caused the corrosion-initiated pits. Approximately 15 other plants with Westinghouse steam generators were examined at the transition joint by means of ultrasonic techniques, and no defects were found.

4 NEW OPERATING PROBLEMS

4.1 Tube Vibration in Westinghouse Models D2/D3

In October 1981 a steam generator tube leak occurred at Ringhals Unit 3 in Sweden, which is a three-loop plant with Westinghouse Model D3 steam generators. Eddy current testing (ECT) indicated that preferential wear resulting from excessive tube vibration was occurring at tube support locations in the outer three rows of tubes (47, 48, and 49) in the preheater section. McGuire Nuclear Station Unit 1, with Model D2 steam generators, was operating at the time of the occurrence at Ringhals Unit 3; therefore, its power operation was restricted to 50% until a solution to the tube vibration problem could be found. ECT at McGuire Unit 1 revealed accelerated tube wear during operation of the plant at the 75% power level for short periods of time.

On the basis of examinations of pulled tubes, accelerometer data from operating plants, and behavorial information from analytical models and from a series of air and water scale model tests, an internal manifold design was proposed for Models D2/D3 to minimize tube vibration at critical locations in the preheater. NUREG-0966 describes the staff's review of the D2/D3 design modification.

The internal manifold modification was installed at McGuire Units 1 and 2 and Virgil C. Summer Nuclear Station allowing them to operate at 100% power. Virgil C. Summer was inspected in November-December 1983 after approximately 5 effective full-months (EFPMs) of operation to establish the adequacy of the design modification to minimize tube wear. The results of these inspections, which included eddy current tests, visual examination of the manifold, and vibration monitoring of tubes, indicated acceptable performance with the design modification.

4.2 Tube Vibration in Westinghouse Models D4/D5/E

Krsko Unit 1, a two-loop Westinghouse plant in Yugoslavia, is the only operating counterflow preheat steam generator. ECT inspections after 1500 hours at 75% power revealed no indications of tube wear; however, metallurgical examinations of a pulled tube revealed the presence of wear scars at three baffle plate locations.

On the basis of operational and accelerometer tube vibration data on the Krsko tubes plus air and water model test data, a modification was proposed that consisted of expanding approximately 124 tubes at 2 baffle plate locations along with splitting feedwater flow by diverting 10% of the main feedwater flow through the auxiliary feedwater nozzle to reduce tube vibration and resultant wear.

The proposed modifications on the Model D4 steam generators at Comanche Peak Steam Electric Station Unit 1 were installed during the summer of 1983. The first inservice inspection of expanded tubes at Comanche Peak will be performed after 12 EFPMs of operation, which will probably be sometime in 1985. The staff's review of the D4/D5/E modification is described in NUREG-1014.

4.3 Tube Damage and Wear Resulting From Loose Parts and Foreign Objects

On January 25, 1982, the R. E. Ginna Nuclear Power Plant experienced a gross tube rupture in steam generator B that resulted in a significant primary system depressurization transient, actuation of the safety injection system, and minor releases of radioactive materials from the plant. Maximum primary-to-secondary leakage during the transient is estimated to have been 760 gpm.

Investigations performed after the rupture revealed the immediate cause of the failure as excessive wear/abrasion that led to a pressure burst of a tube located near the periphery of the tube bundle. Numerous tubes in the peripheral region had been plugged, beginning in 1976, as a result of eddy current indications found during inservice inspections and as a result of small primary-to-secondary leaks.

Visual inspections using television and fiberoptic techniques revealed extensive localized damage to previously plugged tubes in the peripheral area. Numerous foreign objects and pieces of broken steam generator tubing were found in the annular region between the tube bundle and the shell. Most of the foreign objects are believed to have been introduced during steam generator modifications performed during periods dating back to 1975. All loose parts were removed from the steam generators before the plant was returned to service.

It has been satisfactorily established that a large foreign object most probably initiated the damage in steam generator B that led to the tube rupture. The foreign object acted on tubes in the outer row of the steam generator causing sufficient degradation in these tubes to cause them to be removed from service by plugging both ends. The foreign object continued to act on the plugged tubes until they collapsed and eventually severed at the lower end of the tube. These severed tubes were then free to act on adjacent tubes, eventually causing them to be plugged and possibly to sever. This domino effect repeated itself until one tube experienced wear over a long enough length so that it burst rather than developing a small leak or pluggable indication.

Postrupture examination revealed that severe damage had occurred to 26 tubes in the periphery of steam generator B. The damage to these tubes was of such extent as to warrant removal of those tubes to prevent further damage to sound tubes. Details of the Ginna tube rupture event have been reported in NUREG-0909 and NUREG-0916.

As a result of the tube rupture initiated by a foreign object at Ginna, many operating plants and plants under construction with installed steam generators conducted secondary-side examinations to search for and retrieve foreign objects.

Office of Inspection and Enforcement (IE) Information Notice 83-24, "Loose Parts in Secondary Side of Steam Generators at Pressurized Water Reactors," was issued on April 28, 1983, to inform licensees and construction permit holders of a number of facilities that found loose parts in the secondary side of their steam generators.

4.4 Sulfur-Induced Intergranular Stress Corrosion Cracking

In late November 1981, during reactor coolant system hydrostatic testing with the reactor shut down, primary-to-secondary system leakage was detected in both

OTSGs at Three Mile Island Unit 1. Subsequently, detailed examinations revealed many defective tubes. Metallographic examination of portions of removed tubes confirmed that the tube failures were initiated from the primary side (inside diameter) of the tubes in the form of circumferential stress-assisted intergranular cracks. The active chemical impurity causing the corrosion was sulfur in reduced forms, which had been inadvertently introduced into the reactor coolant system from sodium thiosulfate that had been used in the past as a containment spray additive for iodine removal. The vast majority (approximately 95%) of the defects occurred within the top 2 to 3 in. of the 24-in.-thick upper tubesheet (UTS). Corrosion occurs most rapidly at the air/water interface and during layup. The air/water interface was located in the UTS during a significant portion of the post-hot-functional shutdown period. To repair the defective OTSG tubes within the UTS, a kinetic (explosive) expansion repair technique was used. This established a new primary pressure boundary, by expanding and tightly sealing the tubes within the tubesheet below the degraded region, thereby establishing a new leak-limiting/load-carrying seal. The kinetic expansion repair technique was used on all unplugged tubes within the UTS to ensure that all potentially degraded tubes are sealed. Tubes that had defects that were not repairable by the kinetic expansion process have been removed from service by plugging.

A detailed report NUREG-1019, "Safety Evaluation Report Related to Steam Generator Tube Repair and Return to Power Operation, Three Mile Island Nuclear Station, Unit No. 1," was published in November 1983.

Nonnuclear hot functional tests completed in October 1983 indicated only trace leakage from the repaired steam generators.

Sodium thiosulfate had been used as a containment spray additive at two other plants (Crystal River and Arkansas Nuclear One Unit 1) but had been removed before the corrosion incident at Three Mile Island Unit 1.

5 PLANT-SPECIFIC EVENTS

This section provides a summary of plant-specific events that occurred during 1982 and 1983. Plants not listed below have not experienced any significant operational difficulties with their steam generators during this period.

5.1 Westinghouse Steam Generators

Beaver Valley Power Station Unit 1

On July 22, 1982, primary-to-secondary leakage from steam generator 1C in the range of 0.03 to 0.07 gallon per minute (gpm) was detected. The plant was shut down on August 30, 1982, when leakage reached 0.1 gpm. A leak test showed that the leaker was located on the periphery next to the outermost row of tubes. The leak, which was about 0.5 in. above the tubesheet, was located by means of eddy current tests. The tube was plugged and the unit was returned to service. During the summer of 1983 refueling outage, the steam generators were inspected according to Technical Specification requirements. A total of 3387 tubes were inspected in steam generator 1C. Six tubes were plugged: two because of greater than 40% indications, one because of a 38% indication, and three to remove loose parts that had become wedged. In steam generator 1B, 705 tubes were examined and two tubes were plugged; one because of a wedged loose part. The loose parts were removed from steam generators 1B and 1C, and it was postulated that the leakage in July 1982 in steam generator 1C was due to a loose part.

Comanche Peak Steam Electric Station Unit 1

Comanche Peak Unit 1 is the lead plant of the D4/D5/E steam generator series that instituted the proposed modification to correct excessive tube vibrations in the preheater section. In August 1983 the licensee completed the expansion of 124 tubes at baffle locations B and D in each steam generator preheater section. Three tubes required plugging as a result of the tube expansion modification process controls.

Donald C. Cook Nuclear Plant Unit 1

Foreign objects were discovered in the secondary side of the D.C. Cook Unit 1 steam generators when they were inspected during a refueling outage in July 1982, but no tube damage was detected. Objects found included a 6-in.-diameter ball of 1/16-in. wire; two bronze lock nuts 1 in. across the flats and 1/16 to 1/8-in. thick; 2-3/8-in. by 1-1/2-in. cap screws with two nuts, wired together; metal spatter the size of a half dollar; and parts of a pocket knife consisting of one piece of metal 1/2 in. by 1-1/8 in. by 1/16 in. and one piece 1/2 in. by 4 in.

During the July 1983 refueling outage, the four steam generators at D.C. Cook Unit 1 were eddy current inspected. A total of 2740 tubes were inspected in each steam generator. Eleven tubes with greater than 40% wall penetration were plugged as well as three row 1 tubes that had indications of cracking on the inside diameter at the U-bend hot-leg tangent point.

Unexplained tube denting also was found at the top of the tubesheet, primarily in the sludge pile region. On September 9, 1983, three tubes were removed from the hot leg of one steam generator for metallurgical examinations to determine the cause of the damage observed by ECT.

Donald C. Cook Nuclear Plant Unit 2

This unit had experienced leaks in 1980 and 1981 in tubes in the innermost row (row 1) of the tube bundle at the tangent point location of the small-radius U-bend tubes.

In August 1982 two tubes in row 1 leaked and were plugged. One tube was identified by helium leak testing and one by ECT.

On June 23, 1983, steam generator tube leakage was 0.09 gpm when the reactor tripped because of a power supply failure that caused a reactor pump low flow relay to drop out. As a result of the outage, the steam generators were inspected to locate the leaking tubes.

On October 15, 1983, D.C. Cook Unit 2 was shut down because of tube leakage in three of the four steam generators. The leakage rate at shutdown had reached 0.206 gpm; the Technical Specification limit is 1.0 gpm through all steam generators or 0.35 gallon per day through any one steam generator. The leaking tubes were located and plugged before the plant was returned to power in November 1983.

Upon startup there were immediate indications of primary-to-secondary leakage from a tube located in the sludge pile area. Seven hundred tubes were inspected in the sludge pile area of each of two steam generators. Stress corrosion cracking was believed to be the probable cause of the leakage. These tubes were plugged, and an extensive investigation was to be conducted during the planned February 1984 refueling outage.

Farley Nuclear Plant Unit 1

On March 20, 1983, during preparations to start up after a refueling outage and while the plant was in mode 3 (hot standby), noise monitors detected unusual noise in the hot leg to steam generator 1C. After plant cooldown an investigation revealed a piece of a control rod guide tube alignment pin (1 3/4 in. long by 3/4 in. in diameter) in the primary side of generator 1C. No steam generator tube damage resulted because the detected noise resulted in cooldown within a relatively short period. Sludge lancing was performed on the secondary side of the steam generator during the refueling outage, but the primary side was not opened.

R.E. Ginna Nuclear Power Plant Unit 1

The January 25, 1982, tube rupture event caused by tube wear from a severed tube is described in Section 4.3.

Between May 1982 and September 1982 a very small leak (3 cc/hr) was observed in the Ginna Unit 1 steam generators. In October 1982 a rupture in a previously plugged steam generator tube was discovered by video inspection.

The rupture was a fishmouth opening facing the steam generator wrapper. It was 1.25 in. long and 3/8 in. at the widest opening and began 3.5 in. above the top of the tubesheet. The ruptured tube was a tube that had been plugged in January 1976 and was located in the steam generator B hot leg (R39-C69). During video examinations as a result of the steam generator tube rupture on January 25, 1982, this tube was characterized as having outer surface damage, but the damage was not considered significant enough to require removal.

It was postulated that this tube had ruptured during a 2200-psid primary-side hydrostatic test performed before startup in May 1982 as a result of a leak path through one of the plugs which allowed the tube to be pressurized. The tube was removed from the steam generator. ECT during the October 1982 outage showed no degradation of tubes in the periphery of the steam generators. The video inspection also revealed a small piece of weld rod (about 4 in. long) in each steam generator.

In 1983 sleeves were installed at Ginna, and a total of 99 sleeves are now in service.

Indian Point Station Unit 2

In December 1982 Consolidated Edison Co. of New York conducted an examination of all four steam generators at Indian Point Unit 2. Eddy current, profilometry, and visual examinations were performed.

Inspection of more than the required 12% of the hot-leg tubes in each steam generator revealed no tube defects. Profilometry measurements and strain calculations of previously dented tubes indicated no measurable increase in strain in these tubes.

Secondary-side inspections of all the steam generators revealed a small piece of wire. Visual and photographic examination of the flow slots and the lower support plates did not indicate any increase of previously observed degradation. Results of the chemical analyses of the sludge were consistent with previous analyses; iron oxide and copper were the major constituents found in the sludge.

Twenty tubes were plugged because they did not permit passage of the 610-mil probe and they also exceeded a newly imposed strain-based criterion of 25%.

Indian Point Station Unit 3

After the steam generator inspection outage during the fall of 1981, Indian Point Unit 3 operated with a small steadily declining steam generator tube leak, which ranged from 0.003 to 0.006 gpm. During March 1982, the primary-to-secondary leak rate increased to 1.8 gpm and the plant was shut down on March 25, 1982, for inspection and refueling. The leaking tube was identified as R19C47 in the outlet side of steam generator 33. Five of the eight tubes surrounding the leaker that were inspected were determined to be degraded.

An eddy current inspection of all steam generators was conducted, and 2899 tubes with greater than 50% throughwall indications were found in the outlet side of the steam generators. Approximately 72 tubes were found with greater than 40% throughwall indications in the inlet side of the steam generators.

During May and June 1982, four tubes were removed from steam generator 33 for evaluations by nondestructive and destructive examinations. Three tubes were from the outlet side of the steam generator, and one tube was from the inlet side of the steam generator.

These laboratory examinations showed that deep pits were present on the outlet side of the steam generator tubes and that cracks were present on the inlet side of the steam generators. The pits were filled with corrosion products rich in copper and chromium oxide and were located on the tube surface in the sludge side beneath a copper-rich scale on the tube itself. The cracks on the inlet tube side were axial and intergranular and located about 8 in. above the tubesheet. Copper, sulfur, and silicon were found in a partial wall crack. A decision to sleeve pitted tubes was made.

On March 27, 1982, excessive water was found on the lagging of steam generator 32. Visual inspection revealed a hole approximately 3/16 in. in diameter in the steam generator shell at the weld connecting the upper shell to the transition piece. The hole was located about 90° from the feed nozzle penetration and close to another penetration for level instrumentation. Nondestructive inspections revealed extensive cracking (approximately 150 indications) on the inside surface of the transition weld of steam generator 32. Ultrasonic inspection indicated flaws that were, on an average, approximately 3/4 in. deep and 1-1/4 in. long. Subsequently all four steam generators were examined; these examinations showed an average of 170 indications or more for each generator.

Boat and plug samples were removed from steam generator 32 for failure analysis. In the plug containing the leak path, a flaw was found that was characterized as hot cracking of a massive weld repair made during original fabrication. The flaw was detected through image enhancement of the original production radiographs. The leak path intersected this flaw. However, the flaw did not seem to change the direction of the inside surface crack that eventually penetrated the shell wall. In summary, a flaw on the inside surface of the vessel grew in size until it intersected a flaw that had existed since original steam generator fabrication. The flaw continued to grow in size until it became a throughwall crack. Steam erosion had occurred on the leak path walls, and, therefore, it was not possible for metallographical examinations to characterize the surfaces for identification of failure mechanisms. Massive elemental copper deposits were present on the surfaces of the leak path. The initiating inside surface crack intersected at an angle of approximately 45° with the weld centerline and rotated to a vertical plane (perpendicular to the weld centerline) at midthickness and propagated to the outside surface in this orientation. All other cracks were on the inside surface of the girth weld area, parallel to the weld centerline. Metallographic examinations of the boat and plug samples showed the cracking to be transgranular, with slight branching.

It was postulated that the pits served as the stress concentrators from which the cracks were initiated. Cracks did not form without pits being present.

Pitting occurred extensively on the inside surfaces of the steam generators in the girth weld areas. Pits were found with and without cracks. However, no cracks were found independent of pits.

In late 1982 two major steam generator repair programs were initiated at Indian Point Unit 3. These two programs consisted of the sleeving or plugging of steam generators having degradation exceeding the plugging limit of 50% nominal wall thickness for pitted tubes, and weld repair of the secondary-side upper shell to transition cone girth welds in all four steam generators.

The sleeving process consisted of installing, by rolling and hydraulic expansion, a small-diameter tube (sleeve) to span the degraded portion of the parent tube. The sleeves are fabricated of thermally treated Inconel 600 to provide maximum corrosion resistance. Approximately 3000 tubes were sleeved in the 4 steam generators. The girth weld repair program consisted of the grinding out and rewelding of approximately 1200 linear inches of defective welds in all four steam generators.

Kewaunee Nuclear Power Plant Unit 1

An eddy current inspection of the Kewaunee steam generator tubes was performed during April 1983. The initial program was designed to inspect the row 1-row 2 U-bend areas, to inspect the peripheral tubes for possible wear by foreign objects, and to obtain a statistical sampling of the remaining tubes for general degradation and antivibration bar fretting. Identification of defects in generator 1A dictated a program expansion (first expansion) as required by Technical Specifications. When more data became available from both generators, a decision was made to inspect 100% of the tubes in both generators. The extent of inspection in each tube was determined by the relative position of the tube in the generator and the probable degradation mode of that tube.

The inspection results disclosed 4 tubes in generator 1A and 18 tubes in generator 1B that exceeded the Technical Specification plugging limit (degradation greater than 50% wall thickness). In addition to the defective tubes, 19 tubes in steam generator 1A and 31 tubes in steam generator 1B were plugged as a preventative measure.

A photographic-fiberoptic inspection of the secondary side of the steam generators revealed foreign objects on the top of the tubesheet. Two of these objects, consisting of welding rod studs, have been removed. Two additional objects, one of which has been identified as a small bolt and the other which remains unidentified, are firmly held in place at the locations where they were discovered in spite of considerable efforts to retrieve them.

An evaluation was conducted addressing the potential concerns if these parts were left in place. It concluded that operation of the steam generator with the parts in place does not pose the danger of causing rupture of the tubes. This conclusion is based on the immobility of the objects.

McGuire Nuclear Station Unit 1

As indicated in Section 4.1, McGuire Unit 1 has a Model D3 preheat-type steam generator similar to the ones at Swedish Ringhals Unit 3 and Spanish Almaraz

Unit 1, both of which had experienced tube degradation resulting from flow-induced vibration of tubes in the preheater section. The degradation is attributable to excitation of the steam generator tubes from high fluid velocities, when power levels exceed 50% and tube walls are worn down from vibrational rubbing against baffle plates in the preheat sections.

McGuire Unit 1 had accumulated 1093 effective full-power hours at power levels of 50%, 70%, 90%, and 100% when it was shut down on February 26, 1982, for inspection of the steam generator tubes. ECT revealed four tubes with outside-diameter indications in steam generator C. The indications have been attributed to small-volume wear defects estimated to have an upper bound of 4.0×10^{-4} in.^{3}.

On March 14, 1982, McGuire Unit 1 commenced operation at 50% power for an approved 1500 hours except for a brief period (24 hours) of power escalation to 75% for the purpose of gathering vibration measurement data. Vibration data from the instrumented tubes indicated that there is some evidence of fluid elastic instability at power levels above 50%.

Duke Power Co. requested that they be allowed to operate at power levels not to exceed 75% for a maximum of 720 hours after completion of 1500 hours at 50% power on about June 23, 1982. The staff concluded that wear, during the 720 hours at 75% power, resulting from both fluid elastic instability and turbulence would be within acceptable limits. Total wear for the worst of the four previously degraded tubes was calculated to be 1.29×10^{-3} in.^{3}. This defect volume is equivalent to less than 10 mils (23% penetration), which is below the 40% plugging limit.

Eddy current tests conducted after power operation from March 14, 1982, through June 23, 1982, revealed continued wear when power operation is at 75%.

Results of the eddy current tests (ECTs) were as follows:

(1) Steam Generator A

Indications were observed on 15 tubes. Maximum depth was approximately 15%. Affected tubes are the same tubes that showed distorted support plate signals during the ECT in March 1982.

(2) Steam Generator B

No indications were observed.

(3) Steam Generator C

Eight indications were observed on six tubes. The largest indication was on tube R49C40. This tube previously had an indication of less than 20%. The indication has grown to approximately 23%, which is consistent with wear-rate estimates previously made.

(4) Steam Generator D

No indications were observed.

The above ECT evaluations were based on absolute single-coil probe measurements, deemed to be the most effective for measuring wear volumes. One tube in steam generator A was plugged on the basis of the preliminary evaluation of the differential ECT data. This evaluation indicated 46% throughwall wear. It was suspected that this was an overestimation of the wear, but rather than wait until final evaluation of the absolute ECT data, the decision was made to plug the tube to avoid a schedule delay.

McGuire Unit 1 operated between July 1982 and November 1982 at 50% power and for [illegible]20 hours above 50% power at which time another eddy current inspection was conducted. Tubes in rows 47, 48, and 49 were inspected in all four steam generators. Additionally, in steam generator A, row 46 was inspected because more indications had been observed during the previous inspections of steam generator A. On the basis of this ECT examination, a total of six tubes were plugged, five in steam generator A and one in steam generator C. The tube plugged in steam generator C (R49C40) had the largest observed wear scar (~22%) during the July 1982 inspection and was expected to be plugged during the November 1982 outage. This tube had worn to approximately 40% throughwall when inspected in November 1982.

The five tubes plugged in steam generator A all exhibited indications of approximately 25% throughwall wear. These tubes were plugged because their projected wear rates would increase the indications to greater than 40% throughwall with another operating cycle similar to the August to November 1982 cycle. No tubes were plugged in steam generators B and D.

The November 1982 inspection data indicated that the total number of tubes showing indication of wear was 67, including 41 which showed no indication of wear during the July 1982 inspection.

Upon return to power, McGuire Unit 1 was permitted to operate no more than 30 days at 75% power until installation of the modification discussed in Section 4.1). The manifold modification was installed on January 21, 1983, and restart with the modification occurred in the beginning of May 1983. After modification, McGuire Unit 2 operated at full power until March 1984 when refueling and steam generator inspections were initiated.

McGuire Nuclear Station Unit 2

McGuire Unit 2 has a Model D3 steam generator. Its license to operate at 100% power was granted on May 27, 1983. After several weeks of testing, it was readied for installation of the D2/D3 modification, which was started in the summer of 1983 and successfully completed.

North Anna Power Station Unit 1

North Anna Unit 1 was shut down on May 17, 1982, when signals from the loose parts monitoring system were detected coming from the steam generators. The plant was officially placed in its third refueling outage 1 week earlier than planned.

Scheduled ECT was initiated and entry into the primary side of steam generators A and C revealed peening damage to the tube ends in these generators. Two metal objects, possibly steam generator tube plugs, have been recovered.

On March 6, 1983, the loose parts monitoring system detected noises from the secondary side of steam generator C. The acoustical profiles indicated a light mass object.

North Anna Power Station Unit 2

A scheduled steam generator inspection was conducted in April 1982 during the first refueling outage of North Anna Unit 2. The inspection exceeded Technical Specification requirements in that 98% of all tubes in steam generator A, 99% in steam generator B, and 92% in steam generator C were inspected.

Evidence of minor corrosion in the tube-to-support-plate intersections was observed during the review of the ECT data of steam generators A and B. A significant portion of the steam generator C tubes was found to be dented; denting was less than 1 mil. Boric acid conditioning to arrest denting was planned.

Point Beach Nuclear Plant Unit 1

On March 27, 1982, Point Beach Unit 1 underwent a scheduled steam generator inspection. The inspection consisted of hydrostatic tests and ECT of essentially 100% of all the tubes in both steam generators. An 800-psid secondary-to-primary hydrostatic test indicated five leaking tubes, four of which were from leaking plugs. As a result of the hydrostatic tests and ECT, 38 tubes in steam generator A and 14 tubes in steam generator B were plugged.

The plant was operating at a hot-leg temperature of 557°F and 80% power in an effort to reduce steam generator tube corrosion.

On October 22, 1982, Point Beach Unit 1 was shut down for refueling and an eddy current examination of the tubes was conducted. Four tubes in steam generator A and three tubes in steam generator B had greater than 40% indications and were plugged.

All indications greater than 40% found during this inspection were within the tubesheet region and are considered to be intergranular attack (IGA) caused by caustic. All defective tubes identified during this inspection were mechanically plugged. Operation of the unit at a reduced temperature was to be continued to minimize further IGA.

After completion of the ECT, visual inspections of the secondary side of the steam generators were conducted in November 1982. The visual inspections revealed a large (6-in.) C-clamp, a 58-in.-long bar (1/2 in. by 3/8 in. cross section), and other loose objects. The C-clamp was found leaning against two tubes that showed definite signs of mechanical damage. These tubes had developed leakage in 1978 and had been plugged. The foreign objects were removed from the steam generators.

As a result of these visual findings, 1000 tubes in each steam generator were eddy current inspected for damage. Thirteen tubes in steam generator A and five tubes in steam generator B were plugged as a result of indications greater than 40% or other types of mechanical damage.

Approximately 14% of the tubes in each steam generator have now been removed from service by plugging. As a result of the reduced operating temperature, Unit 1 was operating at less than 80% of full power. To increase availability and reliability and to return to full-power operation, the licensee made plans to replace both steam generators of Unit 1. The plant was shut down in late September of 1983 for start of replacement of the steam generators.

The steam generator replacement will be essentially identical to the steam generator replacement conducted at Surry Power Station Units 1 and 2 and similar to those conducted at Turkey Point Units 3 and 4. The steam generator lower shell assembly, including the tubing, channel head, shell, and all interior components, will be replaced with new components. Moisture separation equipment in the upper shell assembly will also be replaced.

Replacement of the steam generator lower assemblies involves the following major steps in the sequence indicated:

(1) Cut all piping connections at the steam generators. Remove instrumentation and insulation.

(2) Cut the steam generators at the transition cone above the tube bundle.

(3) Remove the upper shell and place on storage stand inside containment for refurbishing of moisture separation equipment.

(4) Disconnect steam generator supports.

(5) Remove the lower section of the steam generator from containment and transport to the storage building.

(6) Move the replacement lower section from storage into containment and lower onto supports in the reverse sequence.

(7) Weld replacement sections of reactor coolant piping to the replacement steam generator.

(8) Replace the upper sections of the steam generator and weld to the lower section.

(9) Reconnect main steam, feedwater, and auxiliary piping. Replace instrumentation and insulation.

(10) Perform nondestructive examination of welds and hydrostatically test the installation, as required.

The replacement at Point Beach Unit 1 was completed in March 1984.

Point Beach Nuclear Plant Unit 2

Through the end of 1981, about 117 tubes, approximately 2% of the tubes in the steam generators, had been plugged at Point Beach Unit 2. Degradation was reported to be wastage, IGA, and stress corrosion cracking.

During 1982 the licensee presented a proposal to the staff for sleeving the steam generators which was completed in May 1983.

Prairie Island Nuclear Generating Plant Unit 1

During an inspection outage in the fall of 1983, eighteen tubes were plugged. Ten tubes were plugged in steam generator 11, and eight tubes were plugged in steam generator 12. The percentage of tubes plugged is 1.2% and 0.3% in steam generators 11 and 12, respectively.

Prairie Island Nuclear Generating Plant Unit 2

During an inspection outage in September 1983, twenty tubes were plugged. Five tubes were plugged in steam generator 21, and fifteen tubes were plugged in steam generator 22. The percentage of tubes plugged is 0.8% and 2.4% in steam generators 21 and 22, respectively.

H. B. Robinson Plant Unit 2

In March 1982 during the refueling outage, all tubes in the three steam generators at H. B. Robinson Unit 2 were inspected. A review of the eddy current data revealed that defective tubes in steam generators B and C were primarily the result of phosphate thinning above the tubesheet on the cold and hot legs with some IGA in the tubesheet crevice region on the hot legs of both steam generators.

Maintenance performed on the steam generators included mechanical plugging of tubes with eddy current indications in excess of the Technical Specification plugging limit of 47%, weld repairs, and one special mechanical plug repair. A total of 16 tubes were plugged in steam generator A, 134 in steam generator B, and 49 in steam generator C.

In addition, an inspection of the secondary side of steam generator B was performed to identify any foreign objects capable of causing damage to the tube bundle. No such foreign objects were detected, nor was there any evidence of mechanical damage on the exterior of the tubes inspected.

A midcycle eddy current examination was recommended by the staff on the basis of a corrosion rate of 1.14% per EFPM.

The midcycle inspection at H. B. Robinson Unit 2 was conducted in May 1983. The steam generators were subjected to a state-of-the-art eddy current inspection to detect and quantify tube wall corrosion on essentially 100% of the unplugged tubing. This inspection revealed tube degradation in several distinct regions of each steam generator where degradation has been observed in the past. Although no new corrosion phenomenon was observed, there was an increase in the phosphate wastage attack rate in some regions. The highest corrosion rate was 4.61% per EFPM in the cold leg of steam generator C.

All tubes with eddy current indications in excess of the 47% plugging limit were plugged. A total of 16 tubes were plugged in steam generator A, 139 in steam generator B, and 208 in steam generator C. The plugged tubes included all tubes with detectable indications in the tubesheet crevice.

In addition to the eddy current inspections, an inspection of the secondary side of steam generators A and C was performed with fiberoptics to identify any foreign objects capable of causing damage to the tube bundle. No such foreign objects were detected, nor was there any evidence of mechanical damage on the exterior of the tubes inspected. Steam generator B had been inspected during the December 1982 inspection outage.

On the basis of the corrosion rate calculated from the 1982-1983 inspection data, operation was limited to 4 EFPMs before an inservice inspection was to be conducted.

On September 5, 1983, H. B. Robinson Unit 2 was shut down because of a primary-to-secondary leak in steam generator A. Upon inspection, it was determined that two tubes, row 14, column 19 (hot leg) and row 28, column 57 (cold leg), were leaking.

A review of the ECT tapes from the May 1983 steam generator inspection determined that both tubes exhibited essentially throughwall indications and should have been plugged. On the basis of this information, it was concluded that these indications proceeded to throughwall as would be predicted by previous calculations.

On September 11, 1983, a reexamination of 10% of the ECT tapes from the May 1983 inspection of steam generator A was completed, and no newly missed pluggable indications were discovered. The two tubes in question were plugged and hydrotested satisfactorily.

H. B. Robinson Unit 2 was shut down on November 2, 1983. The licensee decided to shut down the plant because it was found that several steam generator tubes exceeded their plugging criteria. This was discovered during a 100% reexamination of steam generation tube inspection data requested by the staff after a brief shutdown in September as a result of two leaking tubes.

The reexamination revealed a defect in one tube that was 90% throughwall and about 0.4 in. long located at the tubesheet and a defect in another tube that was 78% throughwall and 1.1 in. long located 29 in. above the tubesheet.

There were no steam generator tube leaks at the time the shutdown decision was made, but an inspection of all the steam generator tubes was initiated.

The steam generators at H. B. Robinson Unit 2 currently are being replaced.

Salem Nuclear Generating Station Unit 1

Steam generator eddy current inspections conducted in January through March 1982 revealed the first occurrence of cold-leg, peripheral indications at this unit. The indications were located at the support plate elevations and appear to be a phenomenon similar to that which has affected Prairie Island Unit 2

(NUREG-0886). A total of 48 tubes with indications were found, including 11 tubes with indications exceeding the 40% plugging limit. The licensee elected to plug all tubes with indications exceeding 30% as a conservative measure.

San Onofre Nuclear Generating Station Unit 1

This unit has operated for approximately 4 1/2 EFPMs following sleeve repairs to 6508 steam generator tubes in 1980-1981 with no significant steam generator difficulties.

During the spring of 1982, hydrostatic testing, ECT, and secondary-side visual inspection of the steam generators were performed. Hydrostatic tests revealed minor leakage in three sleeved tubes, believed to be associated with the upper sleeve joints and to be of no safety consequence. Eddy current inspection was performed on a 10% sample of the sleeves and revealed no indications. Eddy current inspections also revealed little progression of IGA in the tubesheet area which had precipitated the previous sleeve repairs. Only eight nonsleeved tubes were found to exhibit IGA indications and were plugged.

Visual inspection of the secondary side of the steam generators, performed with the aid of remote video cameras, revealed numerous loose parts and small pieces of foreign debris resting on the tubesheet in the annular region between the tube bundle and the steam generator shell. The loose parts were 2-in.-diameter, 6-in.-long pieces of the wrapper support bars that had broken off from the tubesheet and wrapper. Five of these broken support bars have been found and removed. Several more support bars have been observed to have been broken away from their installed locations, but are missing. The licensee believes these missing bars were previously removed, most probably during some stage of steam generator manufacture or installation. The licensee has reported that a new wrapper support system was installed in these steam generators during manufacture, and that the wrapper support bars are not required for structural support. No tube damage has been observed near the tubesheet where the visual inspections were performed. However, indications of dents and apparent internal-diameter-type signals have been found at higher elevations in the peripheral tubes. The licensee is continuing an investigation. The staff will review the licensee's inspections and corrective actions before the unit is returned to power.

Sequoyah Nuclear Power Plant Unit 2

On approximately May 9, 1983, it was noted that the primary-to-secondary leakage had increased from 1 gallon per day (gpd) to 150 gpd. On July 19, 1983, steam generator tube leakage increased to 553 gpd, which is above the specification limit of 500 gpd.

Boroscopic examination revealed a foreign metallic object wedged under the tube lane blocking device of steam generator 3, apparently causing fretting of a row 2 U tube. ECT revealed no other tube degradation.

Virgil C. Summer Nuclear Station

In the spring of 1983, the Virgil C. Summer Nuclear Station with Model D3 preheat steam generators underwent steam generator modifications by the installation of manifold assemblies that allowed operation at 100% power. After approximately 5 EFPMs of operation, the steam generators were inspected in the November-December 1983 period and no adverse effects were found.

Turkey Point Station Unit 4

Turkey Point Unit 4 developed primary-to-secondary steam generator leakage on July 6, 1982. Using fiberoptics and ECT, an inspection of the entire periphery of the tube bundle was performed. Minor tube damage and the following foreign objects were found in the secondary side of steam generator B: one check valve pin, one threaded rod with wingnut, one metal plate 1/2 in. by 2 in. by 6 in., one weld rod, one bolt for a check valve pin, one socket, one 5-in. wire, and one flat piece of metal 3/8 in. by 2 in. by 1.5 in. Similar objects were found on the secondary side of steam generators A and C. Except for the objects wedged into place, all loose objects were removed from the steam generators.

Steam generator replacements at Turkey Point Unit 4 were started in 1982 and completed in May 1983.

Watts Bar Nuclear Plant Unit 1

During preoperational visual inspections (using fiberoptics) in March 1983, Tennessee Valley Authority discovered loose material, including nuts, bolts, a grinder wheel, and crystalline deposits, on the secondary side of the Watts Bar Unit 1 steam generators. The plant was under construction at the time, and all the objects were retrieved.

Wolf Creek Generating Station Unit 1

During a December 20-22, 1982, inspection of steam generators at Wolf Creek, Kansas Gas and Electric Company reported finding a 1.88-lb metal wedge (1 in. by 1 1/2 in. by 3 in.) in the secondary side of steam generator B and a 2.8-oz, 6-in. flat file in the secondary side of steam generator C. Additionally, debris consisting of grit, rust, sponge particles, wire bristles, and pieces of wood was found throughout the secondary side of the steam generators. It was not determined whether the loose parts and debris remained after fabrication or were introduced into the steam generators during installation. The Wolf Creek Generating Station was still under construction at that time.

On July 26, 1983, while steam generator A was being pressurized for hydrostatic testing, one to three leaking steam generator tubes were identified. The leaking tubes were plugged after the hydrostatic test.

Yankee Rowe Nuclear Power Station

During Cycle XV operations, primary-to-secondary leak indications were observed and monitored. Following the September 11, 1982, shutdown for refueling, a 150-psi hydrostatic test confirmed leakage in steam generator 1. Leakage before shutdown was estimated to be approximately 130 gpd; the Technical Specification limit is 1440 gpd (1 gpm).

Eddy current inspection of all tubes in steam generator 1 revealed seven tubes with greater than 40% degradation and one tube with 39% degradation. These eight tubes and the leaking tube were mechanically plugged on October 29, 1982.

Yankee Rowe steam generator tubes are stainless steel, and the degradation was attributed to outside-diameter corrosion.

Zion Nuclear Plant Unit 1

Zion Unit 1 was scheduled for a refueling shutdown about March 4, 1982; however, a steam leak unrelated to steam generator leakage forced a shutdown on February 12, 1982. At the time of shutdown, the plant was experiencing tube leakage of about 500 gpd.

On February 25, 1982, while the steam generators were being prepared for examination, fragments from a primary system nozzle cover were found in steam generators 1B and 1D. The stainless steel fragments were identified as parts of an aluminum nozzle cover hinge, and nut, washer, and bolt assemblies. These fragments and cover caused some damage to the steam generator tube ends in steam generator 1D that required extensive repair or restoration.

Steam generator inspections of 100% of the tubes were conducted using helium leak detection techniques in addition to conventional ECT. Test results indicated that the source of primary-to-secondary leakage was confined to a significant number of row 1 tubes at the U-bend tangent point. All row 1 tubes in all steam generators were plugged. Four tubes in row 2 were plugged; these tubes had either helium leakage indications or eddy current indications at the U-bend tangent point.

Tubes were also plugged because of defect indications, which exceeded plugging criteria, at antivibration bar, tube support plate, tubesheet crevice, and cold-leg periphery locations.

Table 5.1 summarizes the operating experience of Westinghouse steam generators through December 1983.

5.2 Combustion Engineering Steam Generators

Arkansas Nuclear One Unit 2

An inservice eddy current inspection was performed on a selected sample of tubes in steam generators A and B at Arkansas Nuclear One Unit 2 during the period from September 14 through September 25, 1982, during the second refueling outage. The previous inservice inspection had been conducted in April 1981, and no tube degradation had been observed.

The first sample included 3% random samples from each generator with exceptions as provided in the Technical Specifications. An additional 6% random sample was inspected in steam generator B when a defective tube was discovered in the first sample. Additional tubes were inspected in both generators to identify and quantify tube denting.

In total, approximately 9.8% (831 tubes) of the tubes in steam generator A and 9.7% (816 tubes) of the tubes in steam generator B were inspected from the hot side, over the U-bend, and partially down the cold-leg side past drilled support plates 10 and 11. Of the 831 tubes tested in steam generator A, 1.5% (132 tubes) were tested full length; of the 816 tubes tested in steam generator B, 1.9% (161 tubes) were tested full length. The multifrequency method of ECT was used during this inspection to accumulate dent, flaw, and sludge depth data simultaneously.

Minor tube wall degradation indications were observed during the data analysis for steam generators A and B in both the hot- and cold-leg sides. Tube location, line 93, row 67, in steam generator B was plugged because of a 45% throughwall degradation indication.

In October 1983, both steam generators A and B were inspected, and no defective tubes ($\geq$ 40% throughwall degradation) were found.

Calvert Cliffs Nuclear Power Plant Unit 1

On May 13, 1982, during refueling operations, inleakage to the reactor coolant system occurred while the level in steam generator 11 was decreasing. This led to the conclusion that there was leakage emanating from steam generator 11.

It was suspected that leakage resulted because a tube was perforated during steam generator 11 tube support plate rim cut, intended to reduce denting. When the steam generator level was lowered to below the height of the suspected perforation, leakage ceased.

Four damaged tubes resulting from the rim cutting operation were located by eddy current examinations and helium leak checks. Three tubes were plugged, and one severely damaged tube was staked and plugged. No service-degraded tubes were found in either of the two steam generators after 886 tubes were examined in steam generator 11 and 1038 tubes in steam generator 12. Tubes also were plugged in each steam generator as part of a preventative modification that involves the cutting and trimming of support plates 9 and 10 from the baffle wall of the steam generator.

In November 1983 the two steam generators were inspected during a refueling outage. A total of 1000 tubes were examined in each steam generator. Indications were found on 35 tubes. Three tubes exceeded the 40% plugging limit and were plugged. Two tube sections were removed for metallurgical examinations, and these tubes also were plugged.

Calvert Cliffs Nuclear Power Plant Unit 2

In the fall of 1982 outage, Unit 2 steam generators were examined. Service-induced degradation was found in tubes of steam generators 21 and 22.

The results of eddy current tests in steam generator 21 showed that of 832 tubes examined, 1 tube showed a 44% wall loss and was plugged. Of 815 tubes examined in steam generator 22, 1 tube had a 59% indication and was plugged. Very slight denting (0.110-mil and 0.143-mil average dent size) was detected in the area of the ninth support plate of both steam generators.

Fort Calhoun Station Unit 2

Inservice inspection of each steam generator was performed from December 27, 1982, through January 1, 1983. Steam generator A had previously been examined during the 1978 refueling outage, and steam generator B had been examined during the 1981 refueling outage.

Approximately 6% of the tubes in each steam generator were inspected using multifrequency techniques. No tube plugging was required as a result of the examinations; one tube in steam generator A had a 20% wall-thinning indication and one tube in steam generator B had a 25% indication. Dent-like indications ranging in size between 0.001 in. and 0.030 in. were observed in the region of tube support plate 8. Sludge-height measurements indicated an increase in the depth of the sludge pile.

The secondary side of both steam generators was visually inspected and no anomalies were found.

Maine Yankee Atomic Power Plant

During the October 1982 refueling outage, the three steam generators at Maine Yankee were inspected. In steam generator 2, 10 tubes had pluggable indications (greater than 40% throughwall), and 12 tubes with greater than 20% indications were all located in the four rows of tubes passing through the low flow region by the batwing and vertical support strip intersections in the U-bend area of the inner rows of tubes. The indications were at the upper apex of the U-bend and were initiated from the outside diameter. These are similar to the degradation locations noted at St. Lucie Unit 1 (described in NUREG-0886).

A total of 1297 tubes were examined in steam generators 1 and 3, and 15 indications were found in the same areas as in steam generator 2. These 15 indications were below 20%, and therefore no tubes were plugged.

The exact cause or mechanism of the tube degradation has not been clearly identified at this time.

Millstone Nuclear Power Station Unit 2

Steam generator tube inspections starting in December 1981 revealed extensive pitting degradation at locations several inches above the tubesheet and affecting both the hot- and cold-leg sides of both steam generators. A total of 1029 tubes were observed to be degraded by pitting, including 704 tubes with indications exceeding the 40% plugging limit. Similar indications had not been observed during previous inspections at this unit.

Three tubes containing eddy current indications were removed from steam generator 1 for laboratory study. Examination of these tubes showed small (~60-mil)-diameter pits as the source of the indications. Similar pitting attack had been observed at Indian Point Unit 3 in October 1981, although the magnitude of such defects appears less severe in the Millstone Unit 2 steam generators.

A test program was conducted to evaluate the potential effects of pitting on tube integrity. These tests were performed on tube specimens containing simulated pits. The test included specimens with individual pits and other specimens with multiple arrays of pits, both in a circumferential and axial orientation. These tests included pit diameters ranging to 0.187 in., which is conservative for pits actually observed at Millstone Unit 2 or Indian Point Unit 3.

Pressure tests demonstrated that pits ranging in depth to 92% of the original wall thickness can sustain loading considerably in excess of the maximum pressure loading associated with a postulated main steam line break (MSLB) with no leakage. When tested to failure, the failures are generally local to the pit (i.e., within the pit) rather than a general or gross failure that could cause large leakage. For severely pitted tubes, the multiplicity of closely spaced pits may degrade tube integrity more than would be indicated by pressure tests of tubes with individual pits, since the failure could involve more than one pit. However, even assuming an axial array of four 0.187-in.-diameter pits, and penetrating 88% throughwall, with a 10-mil ligament spacing between pits, pressure tests have also demonstrated burst pressures in excess of postulated MSLB pressures. The licensee also performed a pressure test on one of the pulled tube specimens that exhibited an 83% field ECT indication. This tube exhibited a burst pressure in excess of 9000 psi, which is close to the strength of as-manufactured tubing and indicative of the high residual strength associated with even severely pitted tubes.

Visual inspection of the secondary sides was performed from both the top of the bundles and from the lower hand holes. The gap between the upper support plates and the shroud, established by the rim cutting operation in January 1978, was reported to be apparently unchanged since previous inspection. No plate-to-shroud contact was reported. The licensee inspected for the presence of loose parts such as were found in previous years as a result of cracking of the tube support plates where the rim cut operation was performed. However, no such pieces were found during this inspection.

From April 1982 Millstone Unit 2 steam generators had been operating with slowly increasing primary-to-secondary leakage, which was 0.286 gpm at the end of February 1983.

Upon inspection of steam generator 1 with the use of a secondary-to-primary-side hydrostatic test, leakage from an unplugged steam generator tube was identified. This leakage was quantified to be 0.21 gpm at a differential pressure of 200 psi.

The leaking tube was located at column 120, row 94 adjacent to a stay rod on the hot-leg side of steam generator 1. The eddy current inspection results for this tube obtained during the previous inspection were rereviewed, and it was concluded that a defect in excess of the plugging limit existed but had been overlooked. The rereview quantified the depth of the defect to be approximately 83% throughwall. The defect has been located at the top of the tubesheet, within the limits of eddy current accuracy, and coincides with various interferences from the combination of deposits, denting, and tubesheet entry.

The eddy current and visual inspections conducted on the defective tube, in combination with the destructive and nondestructive examination results obtained during the 1981/1982 refueling outage, indicate that the failure mechanism responsible for the leaking tube (column 120, row 94) is most probably pitting corrosion. A boroscopic examination of the inside diameter of the leaking tube revealed that the defect appeared to be two pits joined by a crack.

During the June 1983 scheduled inservice inspection, 2557 degraded tubes were identified. Of these, 2139 had greater than 40% throughwall defects and 77 had distorted signals. All tubes were inspected, and a total of 2022 tubes were sleeved on the cold-leg side and 192 tubes were plugged on both ends. Three tube ends were removed for destructive examination.

Palisades Nuclear Plant

The Palisades plant went off line on March 23, 1982, because a primary-to-secondary leak (0.33 gpm) in steam generator A exceeded the Technical Specification limit of 0.30 gpm per steam generator.

Inspection of steam generator A revealed two leaks: one located at the elevation of the ninth support plate on the hot-leg side, and the other in a horizontal leg of a tube near a batwing support. The flaws were identified as circumferential cracks when 4 x 4 differentially linked surface riding pancake coil eddy current probes were used. Further development of these probes was undertaken.

In the fall of 1983, steam generator inspections were initiated during a refueling and maintenance outage. After approximately 10% of the steam generator tubes were inspected using an improved 4 x 4 pancake coil as well as multifrequency techniques with standard differental bobbin coils, approximately 26 tubes with circumferential cracks were found. Two other types of flaws of unquantifiable depth were also found throughout the steam generators. Tube inspections were expanded to include 100% of the steam generator tubes using the 4 x 4 technique supplemented as needed by multifrequency techniques and rotating pancake coils to quantify flaw depth.

Circumferential cracks identified by the 4 x 4 probe, irrespective of depth, will be plugged. Disposition of the remaining tubes with other type flaws will await the results of laboratory examination of pulled tubes, which will undergo ECT correlations with destructive metallurgical examinations. Chemical analyses will also be conducted to determine causative species responsible for the observed degradation. Preliminary correlations of the unidentified flaw types with laboratory-developed IGA samples have been made.

Corrective actions will be based on the results of the above investigations and others, such as in situ strength testing of tubes as a backup to ECT depth determinations.

Tube pulling commenced in November 1983 before the ECT was complete; laboratory results are expected during the spring of 1984.

Palo Verde Nuclear Generating Station Unit 1 and Unit 2

Construction deficiencies and loose parts were found when the steam generators were examined in July 1983.

Washington Nuclear Plant Unit 3

Construction deficiencies and loose parts were found when the steam generators were examined in July 1983.

Table 5.2 summarizes the operating experience with Combustion Engineering steam generators through December 1983.

5.3 Babcock & Wilcox Steam Generators

Arkansas Nuclear One Unit 1

On May 25, 1982, the process monitor for Arkansas Unit 1 indicated a secondary activity level increase attributed to a steam generator tube leak in steam generator A. The plant was at 97% power and there was no detectable primary-to-secondary leakage indicated. The plant was shut down, however, to prevent the contamination of the condensate polishers.

ECT was conducted on 500 tubes in areas where previous degradation had been experienced; that is, the tubes were adjacent to the open inspection lane at the 15th support plate and upper tubesheet. One leaking tube and nine tubes with eddy current indications between 35% and 89% throughwall were plugged as a result of these inspections.

During the Arkansas Unit 1 refueling outage starting in November 1982, an eddy current inspection of the steam generator tubes was conducted. The initial inspections were conducted in once-through steam generator (OTSG) B. These inspections revealed 11 defective tubes in the inspection lane area. Additional defects were located in peripheral tubes adjacent to the lane region. These early inspection results indicated that the defective tubes were localized in an area near the bundle periphery adjacent to the defined lane region. At the time it did not appear that a complete inspection of OTSG B, as specified by the Technical Specifications, was warranted because of the localized nature of the defects. However, after discussions with the NRC staff, additional inspections in OTSG B were agreed on. Inspections conducted subsequent to the above discussions revealed a substantial number of additional defective tubes. Although these defects continued to be concentrated in the area described above, the number of defects outside this area resulted in the decision to proceed with a complete inspection of both OTSGs.

All unplugged tubes in both steam generators were inspected by eddy current techniques, and a total of 131 required plugging because the plugging limit of 40% had been exceeded. Two tube samples were removed for metallurgical analysis in an attempt to determine the mechanism responsible for what appeared to be an active corrosion-driven degradation rate.

Arkansas Unit 1 was taken off line again on July 7, 1983, following indication of an increase in primary-to-secondary leakage since plant startup from the

November 1982 refueling outage. On the evening of July 7, 1983, the leak rate slowly increased to approximately 0.1 gpm. At this point, the decision was made to bring the unit down for repair of the leak. This decision was based on considerations regarding secondary-system contamination. As the unit was being shut down the leakage increased, as expected because of thermal stresses during cooldown, to a maximum primary-to-secondary leakage of approximately 0.2 gpm (as indicated through volumetric analysis). The maximum leak rate experienced during the cooldown was within the limits of the Technical Specification.

The leaking tube (row 77, tube 18) was found during bubble testing of OTSG A. (To accomplish bubble testing, the primary-side water level is lowered to the top of the upper tubesheet (UTS); the shell side of the generator is then pressurized with nitrogen and the secondary-side water level is slowly lowered. Bubbles form in the leaking tube and are exhibited at the primary-side tubesheet as the secondary water level drops past the leak location.) ECT confirmed that the defect was located in tube 77-18 at the UTS face. Because tube 77-18 had had no previous indication of degradation, it was decided that further examination of OTSG A was warranted. Ultimately, a total of 584 tubes were inspected. The inspection included a full-length eddy current examination of all previously degraded tubes and an examination down to the 15th tube support plate of all unplugged tubes in the lane and lane periphery region. The region inspected consisted of 533 unplugged tubes. A total of 43 tubes were plugged as a result of the eddy current inspections; 32 tubes exceeded the 40% plugging limit and were plugged preventively, and 3 tubes were erroneously plugged.

Results of the metallurgical examinations and chemical analyses of the two tubes removed as a result of the December 1982 steam generator inspections revealed throughwall circumferential cracking and IGA. The most probable corrosive mechanism supported by the examination data is sulfur-induced IGA of the chromium-depleted Inconel 600 grain boundaries, which probably occurs at low temperature and low pH and in the presence of oxygen.

A series of system improvements is planned to minimize sulfur and oxygen ingress to the steam generators to reduce the potential for future corrosive attack initiated by these contaminants.

Davis-Besse Nuclear Power Station Unit 1

During an April 1982 scheduled refueling outage of Davis-Besse Unit 1, an inspection of the steam generators was conducted. There were unexplained eddy current indications on the outer tubes in the vicinity of the auxiliary feedwater ring header inside the steam generator (in OTSGs the ring header is a circular pipe attached to the inner wall of the steam generator to distribute water into the steam generator from the auxiliary feedwater system).

Visual inspections using a fiberscope indicated deformation of the header, distorted support brackets, missing support pins, and general damage to the component. The observed eddy current indications were the result of denting of the tubes caused by movement of the ring header because of the collapse of steam inside the header during occasional injection of relatively cold auxiliary feedwater.

Visual examination of the Rancho Seco and Oconee Unit 3 steam generators indicated similar damage to the auxiliary feedwater header.

Oconee Nuclear Station Unit 1

Unit 1 was inspected in March 1982 and April 1982 to locate a 0.11-gpm leak in steam generator 1A and a 0.1-gpm leak in steam generator 1B, respectively. One tube was plugged during each outage because of fatigue cracks in tubes adjacent to the open inspection lane. Approximately 372 tubes were inspected in March 1982, and 374 tubes were inspected in April 1982.

The Unit 1 steam generators were inspected during the summer of 1983 refueling outage. Approximately 3723 tubes were inspected in steam generator A and approximately 8050 tubes were inspected in steam generator B. Six tubes were plugged in steam generator A, and eighteen tubes were plugged in steam generator B. Some tubes that were plugged were also stabilized.

Oconee Nuclear Station Unit 2

In January 1982 after 400 effective full-power days (EFPDs) of operation since the last refueling outage inspection, Oconee Unit 2 underwent a scheduled inservice inspection of the steam generator tubes. Steam generator 2A had two tubes with outside-diameter indications in excess of the 40% plugging limit. A total of 2886 tubes were inspected, or approximately 18.58% of the total number of tubes in the steam generator. Steam generator 2B had seven tubes in excess of the 40% plugging limit, with maximum throughwall indications of 68%. A total of 3634 tubes were inspected, or approximately 23.4% of the tubes in the steam generator.

Oconee Nuclear Station Unit 3

A leaking tube (0.03 gpm) in February 1982 resulted in the inspection of 174 tubes. A tube with a 52% throughwall indication was also found, resulting in the plugging of two tubes.

In June 1982, after 349 EFPDs since the last refueling outage inspection, 5 tubes of 3191 tubes inspected were plugged in steam generator 3A, and 1 tube of 1915 tubes inspected was plugged in steam generator 3B.

Leaks were experienced on October 9, November 17, and December 11, 1982. One tube was plugged in October, five in November, and one in December 1982 after 909, 2278, and 631 tubes, respectively, were inspected.

Rancho Seco Nuclear Generating Station Unit 1

On November 20, 1982, a leak of 4 to 5 gpm developed in steam generator A of Rancho Seco Unit 1. Eddy current inspections identified the leaking tube, and an adjacent tube was found with a 45% throughwall indication. Both tubes were plugged and stabilized.

A fiberoptics probe was inserted into the leaking tube and the crack was located. An approximate 330° circumferential crack approximately 0.010 in. wide was observed. There was some discoloration just above the crack. The crack appeared to be a clean break except for a small area that appeared to have been contaminated with corrosion products washed in from the secondary side of the steam generator and that obscured the surface. The crack exhibited the characteristic sharp peak that has been identified as being in the vicinity of the initiation point in tube samples from lane region tubes removed from an OTSG at another plant.

The 1983 refueling outage steam generator inspection was performed on 930 tubes in steam generator A and 908 tubes in steam generator B. All inspections were full-length tube inspections, and two steam generator B tubes with indications of 38% and 45% were plugged.

On September 17, 1983, unidentified leakge of 1.35 gpm was detected. Three hundred fifty three tubes were inspected, and the leaking tube and two tubes with less than 30% degradation were found between the thirteenth and fifteenth tube support plates.

Three Mile Island Nuclear Station Unit 1

Sulfur-induced tube degradation at Three Mile Island Unit 1 is discussed in Section 4.4. Approximately 810 tubes were plugged which were deemed not repairable by the kinetic expansion process. Postrepair leak testing indicated 24 additional tubes to be plugged, and baseline eddy current tests after kinetic expansion repair indicated about 23 tubes that exceeded the 40% tube wall plugging criterion and were plugged.

Table 5.3 summarizes the operating experience with Babcock & Wilcox steam generators through December 1983.

Table 5.1 Operating experience with Westinghouse PWR steam generators (SGs) through December 1983

Plant name	SG model no.	Operating license issuance date	Secondary water chemistry control	Degradation type*	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)	SG replacement
Yankee-Rowe	**	7/60	AVT***	D,S/SCC-IGA	38	123(2)	-	-
San Onofre 1	27	3/67	Phosphate	D,W,F,S/SCC-IGA	31	954(8)	7000	-
Ginna 1	44	9/69	AVT***	D,W,S/SCC-IGA	6	228(4)	99	-
H.B. Robinson 2	-	9/70	-	-	-	-	-	In progress
Point Beach 1	44	12/70	AVT	-	-	-	12	1984, replaced with 44F
Point Beach 2	44	11/71	AVT***	D,W,S/SCC-IGA	4	117(2)	4150	-
Surry 1	51	5/72	AVT	-	-	-	-	1981, replaced with 51F
Turkey Point 3	44	7/72	AVT	-	-	-	-	1982, replaced with 44F
Surry 2	51	1/73	AVT	-	-	-	-	1980, replaced with 51F
Turkey Point 4	44	4/73	AVT	-	-	-	-	1983, replaced with 44F
Zion 1	51	4/73	AVT***	D,P/SCC	1	498(4)	-	-
Prairie Island 1	51	8/73	AVT***	P,F	2	34(<1)	-	-
Indian Point 2	44	9/73	AVT***	D,W	5	492(4)	-	-
Zion 2	51	11/73	AVT***	D	1	13(<1)	-	-
Kewaunee	51	12/73	AVT***	D	0	72(1)	-	-
Cook 1	51	10/74	AVT	-	0	39(<1)	-	-
Prairie Island 2	51	10/74	AVT	P,F,S/SCC-IGA	1	61(1)	-	-
Haddam Neck	27	12/74	AVT***	D,W,F,S/SCC-IGA	4	69(0.5)	-	-
Trojan	51	11/75	AVT	P/SCC	42	347(3)	-	-
Indian Point 3	44	12/75	AVT	D,P	3	2053(16)	2970	-
Beaver Valley 1	51	1/76	AVT	-	1	9(<0.1)	-	-
Salem 1	51	8/76	AVT	D,F	0	101(0.5)	-	-
Farley 1	51	6/77	AVT	P/SCC	8	282(3)	-	-
North Anna 1	51	11/77	AVT	D,P/SCC	1	284(3)	-	-
Cook 2	51	12/77	AVT	P/SCC	8	79(0.5)	-	-
Salem 2	51	4/80	AVT	F	0	0	-	-
North Anna 2	51	8/80	AVT	-	0	284(3)	-	-
Sequoyah 1	51	9/80	AVT	D	0	0	-	-
Farley 2	51	10/80	AVT	-	5	5(<0.1)	-	-
McGuire 1	D2	1/81	AVT	F	-	87(0.5)	-	-
Diablo Canyon 1	51	9/81	AVT	-	-	-	-	-
Sequoyah 2	51	9/81	AVT	P/SCC	1	1(<0.1)	-	-
Summer	D3	3/83	AVT	-	-	-	-	-

*D = denting, S/SCC-IGA = secondary-side stress corrosion cracking/intergranular attack, W = wastage, F = fretting, P/SCC = primary-side stress corrosion cracking, P = pitting.

**No model number. Yankee-Rowe uses 304 stainless steel tubing; all other PWRs use Inconel 600 tubing.

***Started on phosphate water chemistry.

NOTE: AVT = all-volatile treatment.

Table 5.2 Operating experience with Combustion Engineering PWR steam generators* through December 1983

Plant name	Operating license issuance date	Secondary water chemistry control	Degradation type**	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)
Palisades	3/71	AVT***	D, W, P, S/SCC	2	3750(22)	33
Maine Yankee	9/72	AVT	D	0	37(<1)	-
Ft. Calhoun	5/73	AVT	W	0	3(<1)†	-
Calvert Cliffs 1	8/74	AVT	D	0	12(<1)	-
Millstone 2	8/75	AVT	D, P	2	1702(10)	2022
St. Lucie 1	3/76	AVT	D, P	1	130(<1)	-
Calvert Cliffs 2	8/76	AVT	D	0	5(<1)	-
Arkansas 2	9/78	AVT	D	0	122 (<1)	-

*Combustion Engineering steam generators do not have specific model numbers. For the plants listed above, the steam generators are of the same basic design with the exception of Palisades. Palisades uses drilled hole support plates for the lower six tube supports instead of egg crate supports.

**D = denting, W = wastage, P = pitting, S/SCC = secondary-side stress corrosion cracking.

***Started on phosphate water chemistry.

†Tubes were plugged because they are used to structurally support the support plate, not because of any degradation.

NOTE: AVT = all-volatile treatment.

Table 5.3 Operating experience with Babcock & Wilcox once-through steam generators through December 1983

Plant name	Operating license issuance date	Startup date	Degradation type**	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)
Oconee 1	2/73	5/73	F, E/C	11	337(<2)	16
Oconee 2	10/73	12/73	F, E/C	3	39(<1)	-
Arkansas 1	5/74	6/74	E/C, IGA	3	149(<1)	-
Oconee 3	7/74	9/74	F, E/C	5	116(<1)	-
Rancho Seco 1	8/74	8/74	F, E/C	3	20(<1)	-
Three Mile Island 1	10/74	10/74	E/C, IGSCC	***	1204(<4)	-
Crystal River 3	1/77	1/77	E/C	0	33(<1)	-
Davis-Besse 1	4/77	8/77	E/C	2	27(<1)	-
Three Mile Island 2	2/78†	-	-	-	38(<1)	-

*Babcock & Wilcox (B&W) steam generators do not have specific model numbers, but are of the same basic design. B&W plants have been operated exclusively with all-volatile treatment secondary water chemistry control.

**F = fatigue cracking, E/C = erosion/corrosion, IGA = intergranular attack, IGSCC = intergranular stress corrosion cracking.

***Multiple leaks were revealed during hydrostatic tests in November 1981.

†NRC suspended authority to operate.

6 STEAM GENERATOR SLEEVING AND REPLACEMENT

When steam generator tubes become defective, they must be removed from service by plugging to ensure the generator's safe operation. Plugging of large numbers of steam generator tubes results in a loss of heat transfer surface and can eventually require a reduction in power levels. Faced with this prospect, some utilities have elected to replace their steam generators. Such replacements require a long outage, involve considerable cost, and entail significant occupational exposures. To prolong the life of severely degraded steam generator tubes, some utilities, with prior NRC approval, have chosen to repair them by sleeving. Sleeving not only decreases the plant downtime but also leaves the repaired tubes functional.

6.1 Steam Generator Sleeving

Sleeving repairs to restore primary coolant boundary integrity have been performed, to date, on the straight portion of tubing degraded by wastage, pitting, intergranular attack, and stress corrosion cracking. Although adequate for these purposes, at present such repairs do not appear to be a viable alternative for tubes degraded by denting.

The tube sleeving procedure involves inserting a tube of smaller diameter (or sleeve) inside the tube to be repaired. The sleeve is positioned to span the degraded portion of the original tube and is then either hydraulically or mechanically expanded above and below the degraded region. The expanded joints are sometimes brazed to ensure additional leaktightness. Table 6.1 indicates the status of steam generator sleeving at operating plants.

Sleeve material in all cases has been thermally treated Inconel 600, which has high resistance to stress corrosion cracking. For Millstone Unit 2, a bimetallic sleeve was used that consisted of an outer diameter of one Inconel alloy to provide resistance to pitting and an inner diameter of another Inconel alloy to provide optimum resistance to stress corrosion cracking.

The sleeve material used for the Ginna sleeving operation was a bimetallic sleeve consisting of Inconel 600 with a layer of another nickel alloy on the outside.

6.2 Steam Generator Replacement

Primarily, because of economic considerations, when continued steam generator tube degradation results in unacceptable steam generator tube inspection intervals and a permanent reduction in unit power, steam generator replacement is considered.

Two methods of replacement are currently available: (1) reactor coolant pipe cut and (2) channel heat cut. The steam generator replacements at Surry Unit 2 and Surry Unit 1 took place in 1980 and 1981, respectively; the replacements as Turkey Point Unit 3 and Turkey Point Unit 4 took place in 1982 and 1983, respectively. The replacements at Surry were reactor coolant pipe cut replacements; the replacements at Turkey Point were channel head cut replacements. A typical channel head cut replacement occures as follows: The upper steam dome assembly is separated from the steam generator by cutting the steam generator at the top of the transition cone and the channel head just below the tubesheet. The section removed through the containment equipment hatch includes the tubesheet, the tube bundle, and the shell and transition cone, which is capped at both ends. A new shop-fabricated lower assembly is placed onto the original undisturbed channel head, after which the original steam dome and steam separator are placed onto the new tube bundle section and two welds are made at the junctions cut for lower tube assembly replacement. Table 6.2 shows the status of steam generator replacements.

As indicated in Table 6.2, all replacements show an F designation after the model number and as such incorporate many of the design features of the new generation of Westinghouse steam generators (Model F). To minimize the potential for several modes of tube degradation that have been identified to date, the replacement generators include the following improvements:

(1) type 405 ferritic stainless steel quatrefoil tube support plate

(2) thermally treated Inconel 600 tubing and stress relief of the innermost eight rows of the tube bundle to reduce the potential for stress corrosion cracking

(3) expansion of the tubes to the full depth of the tubesheet to eliminate crevices

(4) a flow baffle plate above the tubesheet to direct lateral flow across the tubesheet surface and thus minimize the number of tubes exposed to slduge

(5) an improved blowdown system to increase blowdown capacity

Table 6.1 Status of generator sleeving at operating plants

Plant name	No. of sleeves	Status
Ginna	21*	Complete
Ginna	78	Complete
Indian Point 3	2970	Complete
Millstone 2	2022	Complete
Palisades	39*	Complete
Point Beach 2	4150	Complete
San Onofre	6508	Complete

*Experimental.

Table 6.2 Steam generator replacement

Plant name	No. of loops	Steam generator model Original	Steam generator model New	Completion date	Occupational exposure (man-rem)
Surry 1	3	51	51F	7/81	1759
Surry 2	3	51	51F	9/80	2141
Turkey Point 3	3	44	44F	4/82	2151
Turkey Point 4	3	44	44F	5/83	1305
Point Beach 1	2	44	44F	3/84	<1000
H. B. Robinson 2	3	44	44F	Started 2/84	-

7 STEAM GENERATOR RESEARCH

Steam generator research programs directed at investigating problems arising in operating reactors are being supported by the NRC, primarily the Office of Nuclear Regulatory Research, and the Steam Generator Owner's Group in conjunction with the Electric Power Research Institute (EPRI).

7.1 NRC-Supported Steam Generator Research

The three NRC-sponsored steam generator research programs described in NUREG-0886 continued through 1982-1983. These address (1) steam generator tube integrity, (2) stress corrosion cracking of Inconel 600 in high temperature water, and (3) improved eddy current techniques for inspecting steam generator tubing.

The program objectives and work scope for these continuing programs are described below.

7.1.1 Steam Generator Tube Integrity - Pacific Northwest Laboratory

The original goals of this program - to develop validated models for predicting margins to failure under burst and collapse pressures and leak rates for steam generator tubing found to be degraded in service and to establish the efficiency of eddy current testing for locating and characterizing defects in steam generator tubes - continued during the 1982-1983 period.

Whereas early eddy current characterization and burst and collapse tests of degraded tubing were performed on tubing with simulated flaws, during this report period, eddy current and burst tests were performed on laboratory-produced stress corrosion cracks. Leak rate tests are still to be conducted on laboratory-produced stress corrosion cracks. In 1982 the steam generator integrity program expanded to an 11-task effort on the replaced Surry Unit 2 steam generators now emplaced at a specially built facility at the Pacific Northwest Laboratory. This 11-task program is 60% funded by NRC and the remainder by three foreign countries and EPRI and is designated the "Steam Generator Group Project." The 11 tasks are

(1) steam generator examination facility
(2) generator placement
(3) health physics
(4) information system/statistics/data analysis
(5) postshipment examination
(6) channel-head decontamination
(7) tube unplugging
(8) nondestructive examination - eddy current baseline
(9) secondary-side characterization
(10) tubesheet section removal
(11) nondestructive examination - round robin

By the end of 1983, tasks through the removal of 970 explosive plugs had been completed; subsequent to unplugging, a multifrequency eddy current examination was conducted along all accessible tube sections. This baseline establishes the condition of the generator and will aid in the choice of specimens for further reliability studies using round robin techniques. Secondary-side inspections have been conducted through several generator shell penetrations. Examinations of inner row U-bends, the tubesheet upper surface, and support plates have been conducted. Innovative photographic techniques and devices have been developed which greatly enhanced this effort.

In 1984, efforts will concentrate on primary-side nondestructive testing followed by specimen removal for validation studies and integrity testing. Secondary-side characterization and corrosion product sampling will continue. Other specimens will be removed for laboratory scale examinations of secondary-side cleaning and primary-side decontamination techniques.

7.1.2 Stress Corrosion Cracking of PWR Steam Generator Tubes - Brookhaven National Laboratory

The overall objective of this laboratory's experimental program is to develop data and models that will be used to predict the stress corrosion cracking (SCC) service life of Inconel 600 steam generator tubing under normal and abnormal service conditions. The variables in the testing program include temperature, stress, strain and strain rate, metallurgical structure and processing, and ingredients of the primary and secondary coolant.

Data from this program will be used to develop and refine predictive models for SCC behavior in primary- and secondary-side SCC performance for steam generator tubing. The models will be applicable to tubes for which the processing characteristics and service conditions are known, as they are, for example, for standard production tubes currently in service. The program will also indicate where additional information and testing are required to permit the predictive model to be applied.

SCC data are being generated for Inconel 600 steam generator tubing using U-bend, constant load, and slow extension rate tests. Arrhenius plots are made of failure times or crack rates versus inverse temperature for crack initiation and propagation; the effect of applied load is expressed in terms of log-log curves of failure times versus stress; variations in environment and cold work are included. Microstructure and composition of oxide films stripped from Inconel 600 surfaces are also being examined. These corrosion tests address two simulated conditions: (1) where deformation occurs but is no longer active, such as when denting is stopped, and (2) where slow plastic deformation of the metal continues, as would occur during denting. Laboratory test media consist of pure water as well as solutions to simulate service environments.

7.1.3 Improved Multifrequency Testing of Steam Generator Tubing - Oak Ridge National Laboratory

The objective of this program is to upgrade and validate eddy current inspection probes, techniques, and associated instrumentation for inservice inspection of steam generator tubing. Furthermore, it is desirable to improve defect characterization as it is affected by variations in tube diameter and thickness, tube denting, probe wobble, tubesheet and tube support interference, and location and type of defect.

Preliminary results from this program indicate success in designing and developing improved eddy current equipment and techniques for the inservice inspection of steam generator tubing employing a multifrequency technique. Using design calculations based on theoretical mathematical models, a prototype three-frequency instrument with probes was constructed and laboratory evaluated. This instrument has the capability for either separating and measuring, or discriminating among variations in each of the following parameters: (1) tube diameter, including denting at the support; (2) probe wobble; (3) the presence of supports around the tube; (4) tube wall thickness; (5) location (radial and axial) of defects in the tube wall; and (6) the size of defects.

By the end of 1981, improved instrumentation for field testing had been built, installed in a mobile inspection laboratory, and used successfully for inspections at operating reactors. As a result of field inspections, both hardware and software improvements have been made in the system. Instrumentation is now available that is capable of measuring both the amplitude and phase of the eddy current signal at several different frequencies as well as computer equipment capable of processing the data quickly and reliably.

By the end of 1983, computer studies and experimental tests had shown that small, flat, "pancake" coils pressed against the inside wall of the tubing are an order of magnitude more sensitive to small flaws than are the conventional large circumferential coils, as well as much less sensitive to variations outside the tube, such as tube supports. The small coils achieve these advantages by examining a much smaller region of the tubing. There is one penalty, however, and that is that an array of small coils is needed to scan a whole tube at the same speed as a single large coil. The additional cost and complexity of the array is justified by the great increase in reliability of flaw detections.

The eddy current instrument now contains a microcomputer that must be "trained" to recognize at the different frequencies response patterns that correspond to significant flaws and reject harmless response patterns.

One of the most difficult problems has been to recognize flaws at the edge of a tube support or the tubesheet. It was found that flaw detectability can be maintained by programming a "tube support channel" in the computer to recognize when the probe is inside, outside, or at the edge of the tube support. Then the computer can use different formulas to recognize the flaw patterns in the different regions. Actually, it turns out that the same formula works for the probe completely inside or outside the tube support, and a different formula is needed only for the transition region at the edge of the tube support.

The small pancake coil design probe was utilized in the nondestructive examination round robin performed on the laboratory-prepared stress corrosion cracked samples used in the Pacific Northwest Laboratory program described in Section 7.1.1. The results obtained with the pancake coil probe were superior to those of most of the other round robin participants - see NUREG/CR-3200, Volume 1 (ORNL/TM8796/V1).

7.2 Steam Generator Owners Group and Related Electric Power Research Institute Research

The Steam Generator Owners Group program and related Electric Power Research Institute (EPRI) efforts are designed to provide a better understanding of the known types of corrosion and mechanical damage in steam generators: wastage, denting and its side effects, deep crevice corrosion, stress corrosion and fatigue cracking, erosion, fretting wear, and so forth.

A Steam Generator Owners Group was established early in 1977 for the specific purpose of determining the best solution to the steam generator problems then facing the industry. This early effort, known as the Steam Generator Owners Group I program, has produced a more complete understanding of "older" problems like wastage and denting and has led to at least partial solutions.

On the basis of available plant and laboratory data, guidelines for secondary water chemistry control have been prepared for use by the utilities.

Additionally, it has been learned that (1) thermally treated Inconel 600 tubes are more resistant than mill-annealed tubes to stress corrosion cracking in primary water, (2) the concentration of harmful chemicals that hide out or accumulate in the steam generator at power can be reduced by soaks at zero power with subsequent blowdown or drain and refill, and (3) flushing of tube-to-tubesheet crevices during layup can remove aggressive chemicals. Also, in the nondestructive examination program, it has been learned that (1) multi-frequency eddy current testing greatly improves the ability to detect, size, and classify the defects in steam generator tubing and tube supports; (2) radiography can be used to detect tube support cracks; (3) induced vibration analysis can quantify tube support crevice blockage; and (4) fiberoptics can be used to inspect the secondary side of steam generators.

The Steam Generator Owners Group II program (1983-1986) is based on work done for Steam Generator Owners Group I and will be complemented by work being sponsored by other departments of the Nuclear Power Division of EPRI.

Although the impact of denting and wastage has been demonstrated earlier, manifestations of tube cracking and intergranular attack in the open crevices of the tubesheet and in some tube support plate crevices, tube cracking from the primary side in regions of high stress, such as tight radius U-bends, and some roll transitions have continued. Recent instances of tube pitting, tube wastage under the tube support on the cold leg of other units, and tube fretting in some preheat units are considered "new" problems.

The Steam Generator Owners Group II program is designed to address the continuing and new steam generator problems in operating reactors.

The program is divided into 11 projects, which are divided into 4 different elements.

(1) Specific steam generator problems are first addressed, as follows:

    (a) intergranular attack and tube cracking in and above crevice and dry out regions

(b) primary water cracking of Inconel 600

(c) pitting of steam generator tubing

(d) tube fretting and wear in preheat steam generators

(e) effect of sludge, scale, and deposits on corrosion in steam generators

(2) Work is included to support implementation of solutions to other problems:

(a) steam generator chemical cleaning process development and evaluation
(b) improved tube support device materials and designs

(3) Work is also included to support the conduct of the program and the utility's ability to identify steam generator problems:

(a) improved nondestructive examination techniques

(b) destructive examination of steam generator components

(c) evaluation and improvement of steam generator performance and the effectiveness of preventive and corrective measures

Finally, there is one element that will transfer the technology resulting from the entire program to the utility industry.

8 UNRESOLVED SAFETY ISSUES A-3, A-4, AND A-5

Steam generator tube integrity was designated an unresolved safety issue (USI) in 1978, and Task Action Plans (TAPs) A-3, A-4, and A-5 were established to evaluate the safety significance of degradation in Westinghouse, Combustion Engineering, and Babcock & Wilcox steam generators, respectively. These studies were later combined into one effort because of the similarity of many problems among the PWR vendors. As described in NUREG-0886, the staff prepared a draft report in December 1981, which was originally to be published as NUREG-0844, "Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity."

Following the steam generator tube rupture (SGTR) event at Ginna on January 25, 1982, the staff initiated an integrated program in May 1982 to consider the recommendations from the draft USI report above and to assess the lessons that could be learned from the four domestic SGTR events to date. The first three of these events were evaluated in NUREG-0651, "Evaluation of Steam Generator Tube Rupture Events," March 1980. That report includes evaluations of system response, operator actions, and radiological consequences during the three events. The event at the Ginna plant was addressed in NUREG-0909, "NRC Report on the January 25, 1982 Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant," April 1982, and plant restart was evaluated in NUREG-0916, "Safety Evaluation Report Related to the Restart of R. E. Ginna Nuclear Power Plant," May 1982. NUREG-0909 includes descriptions of the event and significant staff findings; NUREG-0916 is an evaluation of system response, operator response, and emergency preparedness radiological consequences and steam generator inspection and repair programs.

As part of the integrated program, the staff has performed a generic assessment of public risk from STGR-related causes. The major finding stemming from this assessment is that the risk of core melt from events involving SGTRs is a relatively small fraction of total risk of core melt from all causes. However, steam generator tube degradation does appear to be a significant contribution to occupational radiation exposure and to the probability of large non-core-melt releases. Pending the formal determination regarding the resolution of the steam-generator-related USIs, the staff has concluded that continued operation of operating PWRs and the licensing of new PWRs does not impose an undue risk to public health and safety.

The staff has prepared a draft report to be designated as NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity." This report supersedes the earlier draft USI report referred to in NUREG-0886 and constitutes the staff's proposed resolution of the USIs. Upon consideration by the Commission (expected to occur in spring 1984), the proposed USI resolution will be issued for public comment, after which the staff will make a formal determination regarding resolution of the USIs.

9 CONCLUSIONS

During the 1982-1983 period, three new problems were encountered in operating steam generators. These were (1) excessive tube vibration and accelerated tube wear in Westinghouse Model D and Model E steam generators, (2) loose parts in the secondary side of steam generators initiating damage to the outside diameter of tubes, and (3) widespread primary-side intergranular stress corrosion cracking of tubes in the tubesheet area resulting from sulfur ingress from the containment spray system containing sodium thiosulfate.

Design modifications to minimize excessive tube vibrations in Westinghouse Model D steam generators have been installed in operating plants, and recent inspections and tests indicate that the modifications are effective solutions to the accelerated wear problems.

Secondary-side inspections using fiberoptics and miniature video cameras have been successfully used in locating secondary-side loose parts so that effective retrieval could be accomplished. Loose parts monitoring systems have also been used to indicate the presence of loose parts in steam generators.

The tubes in the once-through steam generator that suffered widespread sulfur-induced stress corrosion cracking were repaired by means of a kinetic expansion process to form the tube against the tubesheet; that is, close the radial gap and produce an interference fit between the tube's outside diameter and the tubesheet drilled hole inside diameter to achieve a leaktight, load-carrying joint. In addition, sulfur removal was accomplished by cleaning all primary surfaces with a dilute solution of hydrogen peroxide.

During the 1982-1983 period, degradation mechanisms previously found in recirculating and once-through steam generators were still active but at a somewhat diminished rate as secondary water chemistry controls were tightened and secondary-side modifications were made. Tube sleeving and steam generator replacements also took place.

Operation of replacement steam generators, currently only Westinghouse Models 44 and 51 with Model F type material and design features, has apparently been trouble free.

The staff's report of the proposed resolution of the USIs is expected to be issued for public comment in the summer of 1984.

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NRC FORM 335 (6-83) U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by TIDC add Vol No, if any): NUREG-1063

2. Leave blank

3. TITLE AND SUBTITLE

Steam Generator Operating Experience Update 1982-1983

4. RECIPIENT'S ACCESSION NUMBER

5. DATE REPORT COMPLETED

MONTH	YEAR
December	1983

6. AUTHOR(S)

L. Frank

7. DATE REPORT ISSUED

MONTH	YEAR
June	1984

8. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Division of Engineering
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

9. PROJECT/TASK/WORK UNIT NUMBER

10. FIN NUMBER

11. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Division of Engineering
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

12a. TYPE OF REPORT

12b. PERIOD COVERED (Inclusive dates)

13. SUPPLEMENTARY NOTES

Technical Report

14. ABSTRACT (200 words or less)

This report is a continuation of earlier reports by the staff addressing pressurized water reactor steam generator operating experience. NUREG-0886, "Steam Generator Tube Experience," published in February 1982 summarized experience in domestic and foreign plants through December 1981. This report summarizes steam generator operating experience in domestic plants for the years 1982 and 1983. Included are new problems encountered with secondary-side loose parts, sulfur-induced stress-assisted corrosion cracking, and flow-induced vibrational wear in the new preheater design steam generators. The status of Unresolved Safety Issues A3, A4, and A5 is also discussed.

15a. KEY WORDS AND DOCUMENT ANALYSIS

Steam Generators
PWRs
Tube Degradation
Operating Experience 1982-1983

15b. DESCRIPTORS

16. AVAILABILITY STATEMENT

UNLIMITED

17. SECURITY CLASSIFICATION (This report): Unclassified

18. NUMBER OF PAGES

19. SECURITY CLASSIFICATION (This page): Unclassified

20. PRICE: $

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

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NUREG-1063 STEAM GENERATOR OPERATING EXPERIENCE UPDATE 1982-1983 JUNE 1984