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Review of Industry Responses to NRC Generic Letter 97-06 on Degradation of Steam Generator Internals

Brookhaven National Laboratory

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
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ABSTRACT

This report presents the results of an assessment of the nuclear power industry's responses to NRC Generic Letter (GL) 97-06 on the degradation of steam generator (SG) internals experienced at Electricite de France (EdF) plants in France and at a United States (U.S.) Pressurized Water Reactor (PWR). Before issuing the GL, with the exception of a few licensees, there were no formal inspection programs, nor any industry guidelines for monitoring the secondary side internals of steam generators. Nonetheless, all licensees have been performing some inspection and maintenance on their steam generator internals and have found no significant degradation in them. Most of the steam generators in U.S. plants do not appear susceptible to the degradation found at EdF and in the U.S. PWR.

The Westinghouse (W) Models 44, 51, 51M, and D3 and the Combustion Engineering Model 67 with carbon steel eggcrates potentially could experience degradation similar to that found at EdF plants and the U.S. PWR. Recent inspections showed that replacement steam generators made by Babcock & Wilcox International of Canada may be vulnerable to tube proximity problems. The owners groups identified possible degradation mechanisms for these models in their assessments and have evaluated their potential causes. Recommendations were made to monitor for these types of degradation.

During this assessment, each owners group identified for its steam generator models all the potential internal components that are vulnerable to degradation while in service. They provided inspection- and monitoring-guidance and recommendations for their particular SG models. The Nuclear Energy Institute (NEI), who has been coordinating the industry's response to this GL, has incorporated in NEI 97-06, "Steam Generator Program Guidelines" a requirement to monitor secondary side SG components if their failure could prevent the SG from fulfilling its intended safety-related function. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

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The staff of the U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 97-06 on December 30, 1997 to alert licensees of Pressurized Water Reactors (PWRs) to the findings of damage to steam generator (SG) internals, namely, tube support plates and tube bundle wrappers, at foreign PWR facilities. The GL also addressed recent findings of damage to the tube lattice bar-type supports of SGs at the San Onofre Nuclear Generating Station (SONGS) and emphasized the importance of comprehensively examining SG internals to ensure that the structural integrity of the steam generator tubes is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50. The GL required all licensees to submit information that would enable the NRC staff to verify whether the steam generator internals in U.S. Nuclear Power Plants comply with, and conform to, the licensing basis for their respective facilities.

The results presented in this report are based on the following information: the licensees' submittals in response to GL 97-06, Electric Power Research Institute (EPRI) report on the modes of degradation detected in SG internals, owners groups' reports on the evaluation of the foreign PWR degradation and that at SONGS, responses of owners groups to NRC's requests for additional information (RAIs), and limited discussions with steam generator (SG) manufacturers. The technical work on this review was largely completed in the Fall of 1998. At that time, the owners groups' assessments, while completed in some cases, were still listed as interim; in other cases, they had not been completed. The Westinghouse owners group evaluation of its SG models F, 44F, D and E2 was completed in December 1998. The Babcock & Wilcox owners group report on once-through steam generator internals was completed in February 1999. Thus, the final evaluations of all degradation identified in the GL for these SGs became available during the Spring of 1999. Most plant submittals are based on the owners group reports and past inspections of their steam generators. The Nuclear Energy Institute (NEI), who has been coordinating the industry's response to this GL, has incorporated in NEI 97-06, "Steam Generator Program Guidelines" a requirement to monitor secondary side SG components if their failure could prevent the SG from fulfilling its intended safety-related function.

Degradation of steam generator tubes has been known in the nuclear industry from the mid-seventies and there are several guidelines from the EPRI on maintaining the structural integrity of and preventing leakage from *SG tubes*. However, there were no explicit industry guidelines for an *SG secondary side internals* inspection program. Many of the reported activities in this area by the licensees resulted from self-identified problems over the past 25 years of service. In response to the GL, the owners groups have identified additional SG internal components that could be vulnerable to degradation, and have suggested inspection guidelines to address these concerns.

The evaluations of the degradation at foreign PWRs and that at SONGS, which are the subject of this GL, were undertaken by the owners groups in conjunction with NEI. Westinghouse (W) SGs involving models 44, 51, 51M, and D3 and Combustion Engineering (CE) SGs with carbon steel eggcrate tube supports appear to be the most susceptible to the types of degradation identified in the GL. The replacement SGs by Babcock & Wilcox (B&W) are susceptible to peripheral tubes coming into contact during operation and so may incur fretting wear from flow-induced vibration at the point of contact. Specific recommendations were made by the W owners group, the CE owners group, and the B&W owners group to address these potential concerns. All licensees have reported no significant degradation in their SG internals at this time. Appropriate corrective and preventive measures have been implemented to mitigate any significant past problems associated with SG internals. None of the

existing degradation has been progressing based on sequential inspection data. Therefore, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. However, plants have either implemented or are planning, as appropriate to their SGs, the implementation of the recommendations of its owners group and/or by the industry to address the long-term effects of the potential degradation mechanisms associated with the SG internals.

All SGs indicated that some program (formal or informal) for monitoring degradation of SG internals is in place and that inspections are typically carried out at each refueling outage (although not usually for all SGs at each refueling outage). Several plants with a history of problems similar to that described in the GL had already performed, or had plans to perform, comprehensive inspection of their SG internals during the next scheduled refueling outage. Further, several plants had replaced their SGs with new, improved designs. These improved designs included the use of corrosion-resistant materials and better monitoring techniques which had significantly contributed to industry-wide enhanced management programs for SG internal components. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

ACRONYMS

AFW	Auxiliary Feedwater
ANO	Arkansas Nuclear One
ASME	American Society of Mechanical Engineers
AVB	Anti-Vibration Bars
AVT	All Volatile Treatment
BOP	Balance of Plant
BRSG	Babcock & Wilcox Recirculating Steam Generator
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owners Group
BWI	Babcock & Wilcox International (of Canada)
BNL	Brookhaven National Laboratory
cm	Centimeter
CC	Chemical Cleaning
CFR	Code of Federal Regulations
CE	Combustion Engineering
CEOG	Combustion Engineering Owners Group
CR	Crystal River
CS	Carbon Steel
DHR	Decay Heat Removal
EC	Eddy Current
ECT	Eddy Current Testing
EdF	Electricite de France
EFPY	Effective Full Power Year
EFW	Emergency Feedwater
EPRI	Electric Power Research Institute
FAC	Flow-Accelerated Corrosion
FIV	Flow-Induced Vibration
FOSAR	Foreign Objects Search and Removal
FTI	Framatome Technologies Inc.
FW	Feedwater
gpd	Gallons per day
GDC	General Design Criterion
GL	Generic Letter
ID	Inside Diameter
IGA	Intergranular Attack
IGSCC	Intergranular Stress Corrosion Cracking
ISI	In-Service Inspection
lpd	Liters per day
LOCA	Loss of Coolant Accident
MS	Moisture Separator
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NPP	Nuclear Power Plant

ACRONYMS

NRC	Nuclear Regulatory Commission
OD	Outside Diameter
ODSCC	Outside Diameter Stress Corrosion Cracking
OEM	Original Equipment Manufacturer
OG	Owners Group
OTSG	Once-Through Steam Generator
PPC	Pressure Pulse Cleaning
PSI	Possible Support Indication
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RAI	Request for Additional Information
RFO	Refueling Outage
RPC	Rotating Pancake Coil
RSG	Replacement Steam Generator
SG	Steam Generator
SGMP	Steam Generator Management Project
SID	Support Plate Inspection Device
SL	Sludge Lancing
SONGS	San Onofre Nuclear Generating Station
SS	Stainless Steel
SSE	Safe Shutdown Earthquake
TMI	Three Mile Island
TSP	Tube Support Plate
U.S.	United States
UT	Ultrasonic Testing
W	Westinghouse
WOG	Westinghouse Owners Group
WS	Water Slapping (or Lancing)

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1 INTRODUCTION

The staff of the U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 97-06, "Degradation of Steam Generator Internals" (Ref. 1) on December 30, 1997 to alert licensees of pressurized water reactors (PWRs) to findings of damage to steam generator (SG) internals at foreign PWR facilities, namely, tube support plates and tube bundle wrappers. The GL also addressed recent findings of damage to steam generator tube lattice bar-type supports at a U.S. PWR facility and emphasized the importance of comprehensively examining SG internals to ensure that structural integrity of the steam generator tube is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50. The GL required all licensees to submit information that would enable the NRC's staff to verify whether the steam generator internals in U.S. Nuclear Power Plants comply with, and conform to, the licensing basis for their respective facilities.

The NRC requested Brookhaven National Laboratory (BNL) to assist the staff in determining the adequacy of the responses by the nuclear power licensees to GL 97-06. BNL evaluated the adequacy of each licensee's program in meeting the intent of GL 97-06 in separate technical reports for each group of SGs. BNL assessed two types of SGs manufactured by Babcock and Wilcox (B&W), three types of SGs manufactured by Combustion Engineering (CE), and four types of SGs manufactured by Westinghouse (W). Since each plant either has a program in place (formal or informal) to detect SG internals degradation or has plans to establish such a program, an evaluation of licensees' rationale to conclude that no such program is needed was not necessary. A final report summarizing the results and identifying the actions by each licensee to develop and implement an effective inspection program for SG internals to meet the intent of the GL 97-06 was issued on January 26, 1999 (Ref. 2).

During the Spring of 1999, the Westinghouse evaluation of a second group of its SG models and the B&W assessment of its once-through steam generators became available for review. This report contains the findings from the review of these two reports as well as the results of the post-shutdown evaluation of the recent SG failure at Indian Point 2. CE's response to NRC's requests for additional information (RAIs) on the topical reports addressing the issues identified in the GL 97-06 also is included.

1.1 Historical Background (Refs. 3-5)

For over a quarter of a century, the nuclear power industry has focused on managing and repairing steam generator tubing, and has expended considerable resources to meet the challenges posed by their continuing degradation. During the mid-seventies, licensees experienced tube wastage degradation in their SGs and were forced to plug tubes at a rate that would exceed the SG's 40-year-life design margins. Sodium phosphate, employed in the conventional water-treatment process, concentrated in crevices and other areas of localized boiling, leading to aggressive corrosion and wastage (generalized tube thinning) in those regions. The industry corrected this by changing to an All-Volatile Treatment (AVT) by adding ammonia to water that had been highly purified to maintain near neutral pH. However, this approach resulted in conditions conducive to corrosion of the carbon steel support plates. The corrosion products built up in the holes where tubes passed through the plates, eventually squeezing and denting the tubes. At some plants, impurities from external condensers leaked into the secondary water, contributing even more corrosive materials to sludge piles and leading to severe pitting of the tubes. The industry, in collaboration with Electric Power Research Institute (EPRI), implemented SG programs by improving the control of secondary-side water chemistry, taking steps to prevent in-leakage of condenser cooling-water or air, and upgrading secondary-side equipment, and thus, essentially eliminated wastage, denting, and pitting as active degradation mechanisms.

The most pervasive type of tube degradation in PWR steam generators today is intergranular corrosion, in which the chemical attack tends to follow grain boundaries in the tube metal. Without significant stress, the grain boundaries degrade more or less uniformly, beginning at the surface (known as intergranular attack - IGA). IGA has been a major problem in the crevices between the tubes and the tubesheet, where piles of sludge tend to build up. If the metal has relatively high residual stresses from fabrication or generated by operation, cracks may propagate into the metal along grain boundaries (called intergranular stress corrosion cracking - IGSCC). IGSCC is common at the top of the tubesheet where the tubes are expanded to achieve a tight seal, and also in the U-bend region of tubes in recirculating SGs which are exposed to considerable stress during fabrication. Once-through SGs, which contain only straight tubes, have experienced generically similar types of problems but at different locations. Licensees have prevented the buildup of corrosion products in several ways, thereby reducing deterioration of the tubes: crevice flushing to remove caustic materials; using tube materials with greater corrosion resistance; using thermal treatments at lower temperatures and for longer than those involved in mill annealing in U-bend regions; and using broached (as opposed to drilled) holes or lattice bar-type tube supports ("eggcrate" supports) to allow free flow around the tubes. Recently, organic amines were used in the secondary water to reduce the transport of iron and copper, which contribute to sludge buildup. Also, other volatile chemical additives (ammonia, morpholine, and boric acid) are being tested as chemical buffers to maintain neutral pH in crevices.

In addition to tube degradation experienced in PWR steam generators, other secondary side internal components in certain SG designs have deteriorated during their service life. The majority of damage to the feedwater system was caused by the erosion-corrosion of carbon steel components, including the sparger, liner, and the distribution box, or by waterhammer events. In W-designed SG models mechanical wear has caused fretting at anti-vibration bars (AVBs) and at baffle plates in preheater models. CE-designed SGs have experienced erosion of the carbon steel feedwater components. B&W-designed once-through steam generators (OTSGs) had problems with their internal auxiliary feedwater (AFW) headers, and in replacement steam generators (RSGs) the peripheral tubes in contact during SG operation may be subjected to flow-induced vibration fretting wear at their points of contact.

The industry has taken actions to control the degradation of tubes and secondary side internal components to within manageable levels, and maintenance and monitoring programs are in place at each plant to assure that the safety significance of the SGs has not been compromised. These approaches include eddy current inspection, visual/video camera inspections, periodic sludge-lancing (SL)/water-slapping (WS) or pressure-pulse cleaning (PPC)/chemical cleaning (CC) of tubesheets and tube bundles, and undertaking routine foreign objects search and removal (FOSAR) at each refueling and/or maintenance outage(s). Most such guidelines developed by the industry are primarily focused on the tube bundle region of the steam generators, except the ASME Section XI In-Service Inspection (ISI) for welds in ASME pressure vessel components. Very little industry guidance for inspecting secondary side SG internal components to detect and monitor degradation was available until issuance of GL 97-06.

1.2 NRC Generic Letter 97-06

Visual inspections conducted by Electricite de France (EdF) in June 1994 and eddy current examinations in April 1995 found six types of degradation in the SG internals in their PWR plants. They include (1) erosion of the top tube-support-plate (TSP) associated with chemical cleaning, (2) ligament cracking at the top TSPs due to mechanical loading, (3) FAC-induced thinning of the periphery of the top TSP due to ammoniated water, (4) wrapper drop, (5) fatigue cracks emanating from the wrapper-support blocks, and (6) TSP wedge-block cracking (Ref. 6). Based on the French experience, the NRC issued Information Notice 96-09 (Ref. 7) and a later supplement, Information Notice 96-09, Supplement 1 (Ref. 8) to alert U.S. licensees to these kinds of degradation in SG internals. During the Spring 1997 refueling outage (RFO) at SONGS 3, the licensee identified the seventh type of degradation associated with SG internals. This includes erosion-corrosion degradation of the eggcrate supports in the periphery region, and in the untubed staywell region of the tube bundle. In response to both the foreign and U.S. experience, the NRC issued the subject Generic Letter 97-06, "Degradation of Steam Generator Internals" (Ref. 1), to all PWR licensees on December 30, 1997.

GL 97-06 required each PWR licensee to submit the following information:

(1) A discussion of any program in place to detect degradation of steam generator internals, and a description of the inspection plans, including the inspection's scope, frequency, methods, and the equipment used.

The discussion should include the following information:

(a) Whether inspection records at the facility have been reviewed for indications of signal anomalies from tube support plates during eddy current testing of the steam generator tubes that may suggest that the support plates are damaged or ligaments are cracking. If the licnesee has made such a review, the findings should be discussed.

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been done at the facility to gain information on the condition of the steam generator internals (e.g., support plates, tube bundle wrappers, or other components). If such inspections were made, they should be discussed.

(c) Whether degradation of steam generator internals was detected at the facility, and how it was assessed and remedied.

(2) If the licensee currently has no program to detect degradation of steam generator internals, a discussion and justification of the plans should be given along with a schedule for establishing such a program; otherwise the reasons should be given why no program is needed.

1.3 Industry Activities in Response to GL 97-06

The U.S. industry, coordinated through the NEI's SG Internals Task Force in January 1997, developed a program to address the NRC's concerns about the French and SONGS experience. Participants on NEI's task force included the Electric Power Research Institute (EPRI), licensees, and representatives of the SG owners groups for each domestic manufacturer and supplier (i.e., Westinghouse, Combustion Engineering, and Babcock & Wilcox).

EPRI's topical report (GC-109558, December 1997), "Steam Generator Internals Degradation: Modes of Degradation Detected in EDF Units," (Ref. 6) describes the seven modes of degradation detected in SG internals and includes preliminary evaluations of their causal factors. This assessment was made by meeting with EdF, Framatome, and representatives from US licensees, NEI, and EPRI on April 9 and 10, 1997, and by reviewing supporting information in EdF reports on their SG experience (Ref. 9). The EPRI report corroborated the NRC staff's understanding of the issues as they were related to them by the foreign regulatory authorities.

Each owners group then initiated programs to assess safety concerns encompassing the susceptibility to tube damage or loss of decay heat removal (DHR) capability due to degradation of SG internal components on the secondary side. The groups used the EPRI report (Ref. 6) on the EdF causal factors to gain insights into the applicability of the French experience to their SG designs and operating history. In developing the susceptibility assessment, each owners group considered the following attributes of their SGs: design elements, fabrication and manufacturing techniques used, and the plant's operating history. Additionally, through industry-wide surveys, the owners groups compiled and evaluated information on eddy current testing, visual/video inspection of internals, and pertinent experience from non-destructive examinations (NDE) for their SGs currently in service at U.S. nuclear power plants.

The safety and susceptibility assessments on the design and operating history of plants by the Babcock & Wilcox Owners Group (B&WOG), the Combustion Engineering Owners Group (CEOG), and the Westinghouse Owners Group (WOG) were used by respective members in their submittals. In addition to the guidelines provided by the NEI 97-06, "Steam Generator Program Guidelines" (Ref. 10), each owner's group recommended inspection guidelines for SG internals degradation specific to their designs. These latter guidelines are very comprehensive and are the only available documents identifying the SG internal components vulnerable to degradation.

1.4 Objectives and Scope

The primary objectives of this review are (1) to assess the adequacy of each licensee's responses to GL 97-06, and (2) to identify the inspection programs that are in place to detect the degradation of steam generator internals in each plant.

Westinghouse (W), Combustion Engineering (CE), and Babcock & Wilcox (B&W) are the three domestic manufacturers who supply steam generators to all U.S. PWR nuclear power plants. At the time of this review, B&W International (BWI) of Canada fabricated the replacement SGs (RSGs) in nine reactor units with its recirculating SGs, CE at one reactor system with its newer model, and

Westinghouse in eighteen reactor units with its enhanced models during the last two decades. By the end of 2007, owners of six reactor units plan to replace their SGs with BWI recirculating SGs, three reactor units with enhanced Westinghouse SGs, one reactor system with ABB/Ansaldo-designed SGs, one reactor system with Framatome-designed SGs, and two other reactor units had not decided their replacement SG models. Thus, a total of thirteen additional reactor units are scheduled to replace their original SGs. BNL received and reviewed 41 individual licensee submittals involving 69 PWR units, and five sets of owners group's reports for the Westinghouse 51-series and D-series SGs, B&W once-through SGs and replacement RSGs, and the Combustion Engineering SGs. This report summarizes the review of these licensee submittals and evaluates their adequacy in meeting the intent of GL 97-06.

At the time of this review, the steam generators currently operating in 69 PWR units were grouped by their manufacturers or the owners groups, B & W, CE, and W. The B&W Owners Group is divided into two groups: the B & W models with once-through SGs (OTSGs) supplied domestically by B & W, and the B & W replacement SGs by B&W International (of Canada). The three types of CE Owner's Group SGs are considered in one group. The Westinghouse Owner's Group SGs are divided in two groups containing four types of SG models: Westinghouse feed ring models with carbon steel tube support plates (TSPs), preheat models with carbon steel TSPs, feed ring models with stainless steel TSPs, and preheat models with stainless steel TSPs. Indian Point 2 had the only model 44 SGs in service at the time GL 97-06 was issued and in December 2000 they were replaced with model 44F units. Table 1.1 lists the number of plant units in each of these groups.

Table 1.1 Number of Plants for Different SG Owners Groups

SG Manufacturer	SG Owners Group Model Description	No. of Plant Units
Babcock & Wilcox	B&W Owners Group - Once Through SGs	7
	B&W Owners Group - Replacement SGs	9
Combustion Engineering	CE Owners Group - SGs with three different Tube Support Plate designs	12*
Westinghouse	W Owners Group - Feed Ring SGs with Carbon Steel Tube Support Plates	12
	W Owners Group - Preheat SGs with Carbon Steel Tube Support Plates	4
	W Owners Group - Preheat SGs with Stainless Steel Tube Support Plates	5
	W Owners Group - Feed Ring SGs with Stainless Steel Tube Support Plates	20
	Total number of plants	69

* This includes ANO-2 that replaced its original CE SGs with W model D109 SGs in December 2000. Note that W model D109 is not discussed as one of the W D-series SG models in this report.

1 INTRODUCTION

The total number of steam generators in each group depends on the number of primary loops in each PWR unit, and varies from two to four per reactor unit.

Section 2 summarizes NEI's guidelines to its member licensees and outlines recommendations by the three SG Owners Groups to their member utilities for addressing the issues identified in the NRC's GL. Sections 3, 4, and 5 of this report respectively cover BNL's evaluations of licensee responses to the GL for plants with B&W, CE, and W steam generators. Section 6 summarizes the findings and conclusions of this review. Appendix A contains the GL 97-06 and Appendix B provides a list of licensees whose responses to GL 97-06 are evaluated in this report.

2 INDUSTRY GUIDELINES FOR AN INSPECTION PROGRAM FOR STEAM GENERATOR INTERNALS

In response to GL 97-06, the U.S. commercial nuclear power industry established guidelines for SG internals inspection programs. NEI issued general program guidelines in NEI 97-06, and the various SG owners groups have published specific technical information and guidelines related to their SG models.

NEI 97-06, "Steam Generator Program Guidelines," (Ref. 10) establishes a framework for structuring and strengthening existing steam generator programs, and refers licensees to EPRI guidelines for the detailed development of programmatic attributes. Section 3.9 of this document on the maintenance of steam generator secondary-side integrity states the following:

> *"Secondary-side steam generator components shall be monitored if their failure could prevent the steam generator from fulfilling its intended safety-related function. The monitoring shall include design reviews, an assessment of potential degradation mechanisms, industry experience for applicability, and inspection, as necessary, to insure degradation of these components does not threaten the structural and leakage integrity or the ability of the plant to achieve and maintain safe shutdown."*

The guidelines for an SG internals inspection program outlined by each SG owners group are comprehensive and intended to assist utilities in addressing the potential concerns in GL 97-06 on degradation. The guidelines are specific to each SG type and are targeted to inspect those portions of the SG internals judged to be susceptible to deterioration. The B&WOG developed inspection recommendations for their OTSGs for specific internal components and locations, while BWI of Canada outlined a very comprehensive program for their replacement RSGs at the first refueling outage (RFO) inspection. The CEOG presented recommendations for SG internals in their assessment reports. Finally, WOG included inspection guidelines for all its models currently in service. With these guidelines and findings from individual plants or industry-wide activities, licensees already have developed, or are developing, the requisite inspection programs.

To meet the high-level performance criteria of NEI 97-06, each SG owners group has recommended inspection programs for detecting and monitoring degradation in SG internals, in response to recent findings in foreign PWRs and SONGS, as delineated in the GL. This section summarizes these recommendations for the three SG manufacturers.

2.1 Plants with Babcock & Wilcox Steam Generators

Two groups of plants have steam generators manufactured by B&W. The first group contains five sites and seven plants whose nuclear steam supply systems (NSSS) were designed and supplied by B&W. All of them have two Reactor Coolant System loops, each with two Reactor Coolant Pumps and one once-through steam generator (OTSG). At the time of this review, the second group includes eight sites and nine plants. All have replaced their original steam generators with enhanced steam generators designed and manufactured by B&W International (BWI) of Canada. Unlike the first group, these replacement steam generators are B&W recirculating steam generators. The RSGs include design features to mitigate many problems experienced with the original steam generators.

2.1.1 B&W Once-Through Steam Generators

Plants: Arkansas Nuclear One 1, Crystal River 1, Davis Besse 1, Oconee 1 ,2 , & 3, Three Mile Island 1

Review of data from secondary-side visual inspections and eddy current tests has shown no generic degradation problems with SG internals in this group of B&W plants. The only internal degradation found was related to the auxiliary feedwater (AFW) headers. At Davis Besse Unit 1 and Oconee Unit 3, these internal headers were stabilized and functionally replaced with external feedwater headers in the early 80s. No further damage associated with the internal AFW header was detected during subsequent tube inspections at these two plants.

For each of the seven modes of degradation described in the EPRI report (Ref. 6) at the foreign PWRs and SONGS, the B&WOG concluded that the OTSGs are not significantly at risk for the same degradation, in the near term. The future susceptibility of the OTSG to these or other forms of degradation was evaluated as part of the B&WOG process to develop a formal SG internals program (Ref. 11).

The B&W owners group, with technical assistance from Framatome Technologies Inc. (FTI), evaluated all potential internal degradation to determine if a formal inspection program is necessary for these steam generators. The FTI report on the OTSG Internals Degradation Evaluation (Report No. 77-5003013-00, February 1999) summarizes the method and the findings of this review (Ref. 12). It discusses all areas of the OTSG identified as being potentially susceptible to degradation, along with recommended inspection procedures, frequencies, and disposition criteria. Each licensee committed to develop a formal inspection program for the SG internals, as appropriate.

Based on the recommendations and conclusions given in the FTI report, the scope and methodology of inspections in Table 2.1 to monitor possible secondary side degradation in the OTSGs are summarized. This is followed by two plant-specific inspection recommendations.

Table 2.1 Recommended SG Internals Inspection Program for B&W OTSGs

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	ECT to verify that the broached hole design TSPs are located properly. Pre- and Post-cleaning visual inspection, especially the 3rd through the 6th , the 9th and 10th TSPs. Fiberscopic inspections following tube-pull operations include secondary side inspections for FAC on the top TSP. The open path left by the pulled tube can be used to visually inspect the condition of the TSPs. Inspections encompass the lower tubesheet through either the 7th, 8th, or 9th TSPs.
Wrapper drop/cracking	Visual inspection of shroud (wrapper or baffle plate) degradation, shift, or drop

SG Components Degradation	Inspection
Upper wrapper welds	Visually inspect upper wrapper welds from above, through the hand hole. If the main FW nozzle is removed for some other reasons, these welds should be visually inspected from below
Feedwater nozzle	Except Davis Besse 1 and Oconee 3, all other plants have external AFW headers requiring no SG internals inspections. At Davis Besse internal headers are visually inspected every 10-years and at Oconee 3 should develop an inspection schedule based on the results of the 3rd 10-year in-service inspection. Visual inspection of feedwater header/spray nozzles at each RFO
Other SG internal components	Visual inspection of AFW, MFW, and EFW nozzles, upper and lower tubesheets, and all kinds of small pipes and pipe fittings

Plant-Specific Inspection Recommendations

Inspection of AFW Internal Headers Davis Besse 1 and Oconee 3

Steam generators at Davis Besse 1 and Oconee 3 are left with stabilized internal AFW headers which were replaced with functional external AFW headers.

(a) At Davis Besse, eddy current examinations of peripheral tubes are performed at each RFO to monitor the tube's integrity. Following Technical Specifications, these headers are inspected every 10 years. Inspections in 1990 and 1998 showed no evidence of movement or degradation of the AFW header nor deterioration of the AFW's supply nozzles and thermal sleeves. One AFW nozzle was stuck in 1998, and was to be inspected again in 2000. Thus, inspection every 10 years should be adequate.

(b) At Oconee 3, eddy current examinations of the peripheral tubes are performed at each RFO to monitor tube's integrity. In 1982, as part of the commitment to the NRC, the internal AFW headers were inspected. Visual inspections were made during the two subsequent RFOs and during the 2nd 10-year ISI outage. Since 1995, 100% eddy current bobbin-coil inspections have been done in peripheral areas that are susceptible to damage. Oconee should develop an inspection schedule for the AFW internal header based on the results of the 3rd 10-year ISI; no specific problems associated with them have been observed to date.

Inspection of Oconee 1 Tube Dings

Dented tubes should continue to be monitored during future outages to determine if either the number of tubes affected is increasing or the severity of denting in those already affected. A suggested severity threshold is to assess by inspecting the plate either visually or with ECT, whether the denting prevents the passage of a 0.510 bobbin probe. Visual inspection could be made by pulling the main feedwater nozzle and looking at the 10th TSP from below through the aspirator port. Tube dings are monitored at all other OTSG plants and included in the ECT data, so that the development of similar patterns could be recognized and assessed.

2.1.2 B&W Replacement Steam Generators

Plants: Byron 1, Braidwood 1, Catawba 1, Cook 1, Ginna, McGuire 1&2, Millstone 2, and St. Lucie 1

At the time of this review eight plants had replaced their original steam generators with the enhanced recirculating SGs manufactured and supplied by B&W International of Canada. Cook 1 replaced its existing Westinghouse SGs with these SGs in the December 2000. The new RSGs were inspected at various points during manufacture and installation, and after final positioning in each plant. In addition, SGs at Millstone 2, Ginna, and Catawba 1 have completed their first fuel cycle and the tubes have been inspected via eddy current examinations, and the upper bundle and tubesheet regions either visually or with a video camera.

For each of the seven categories of degradation at the foreign PWRs and SONGS, the B&WOG concluded that these RSGs are not significantly at risk for the same degradation in the near-term. However, B&W RSGs are uniquely vulnerable to positioning problems with the U-bend components, in which contact could be made between peripheral tubes. The assessment of this situation confirmed that peripheral tubes in contact during SG operation may wear due to flow-induced vibration fretting at their point of contact. Based on further assessment, B&W stated that fretting wear will not unacceptably reduce the tube's walls over a normal 40- or 60-year operating life. Another mechanism assessed due to this situation is tube bundle deposition and the potential for bridging of deposits between tubes in close proximity. Assuming a minimum gap and no vibratory contact, tubes could be bridged in approximately 10 years. However, based on corrosion studies on thermally treated alloy 690 tubing, the B&WOG concluded that no other damage of the tubes will result from bridging in the U-bends.

The B&WOG stated that since these SGs are new, then, after the first outage inspection, each utility should decide upon the need, frequency, timing, focus, and extent of individual inspections. The recommended inspection program in the B&W document (Ref. 13) is comprehensive, covering most SG internal components. Visual inspections are recommended for one SG (of the two to four) in each reactor unit. Inspections are recommended at the first refueling outage (RFO), and from "time to time" thereafter on a rotating basis. All visual inspections include several sample points or a sample region. Table 2.2 shows B&WOG's recommended plan for an SG internals inspection program, and is the same as that carried out at Millstone 2, Ginna, and Catawba 1.

Table 2.2 Recommended SG Internals Inspection Program for B&W RSGs

SG Internal Region	Feature	Inspection
Primary side (via Man-ways)	Tubes for defects, secondary expansion transition, confirmation of support location, sludge accumulation, indication of support deposition, and proximity of peripheral tubes	Eddy current/ Ultrasonic testing as per site program

SG Internal Region	Feature	Inspection
Secondary side tubesheet region (via tubesheet inspection ports)	Tubes within bundle for surface deposits	Visual and swab sampling
	Tubesheet within bundle for sludge-pile zone	Visual (Fiber optic)
	Tubesheet within bundle for sludge deposits and tube/ tubesheet crevice region	Visual and sampling
	Lattice grid (underside of #1) for tube contacts, flow passages, and sludge deposits Lattice grid rim for support blocks and span breaker ends Lattice grid normal tube location Tubesheet periphery for normal tube location, drain channel, and blowdown entrance ports Shroud lower end support blocks	Visual
Secondary side (via steam drum man-way)	Steam drum head for venturi fixity and flow effects. Secondary separators from above for integrity of seal skirt, outlet ports, vent holes, skimmer vanes and gaps, inlet vanes, drain tubes between primary and secondary, and internal man-way/cover/fasteners Primary separators for upper can vent holes and rim, flow arms, secondary drain tubes (lower end), and riser tube to deck joint area Primary separator deck for deposition on upper surface, internal man way/cover/fasteners, structural members, deck/shell lugs, AFW header (as applicable) Riser cone for cone/deck joint, slip ring joint, and recirc. nozzle exit Feedwater header for goose neck, header pipe, header support brackets, J-tubes, J-tube/header welds, J-tube entrance (header inside diameter), flow impingement locations, shroud slip joint, down comer entrance, and shroud pin assembly/weld	Visual
Secondary side U-bend region (via drum)	Tube deposition	Visual, swab sample
	U-bend support structure, tube surface condition, J-tab condition, tube/J-tab contact locations, flat bar U-bend support bars, flat bar/tube contact locations, upper lattice rim, upper lattice rim for visible ends of bars	Visual

SG Internal Region	Feature	Inspection
Secondary side (via cone access port)	FW header outside diameter, J-tubes, J-tube/header weld, impingement zones, FW header inside diameter (video probe)	Visual
Secondary side (via inspection ports)	Lattice grid for normal tube locations, lattice grid rim structure, lattice bar ends at rim, tubes within bundle, lattice bars tube contacts (from above), and lattice bars tube contacts (from below with special tooling)	Visual

These are relatively new model steam generators. Visual inspections at Millstone 2, Ginna, and Catawba 1 after one fuel cycle of operation found no adverse trends.

2.2 Plants with Combustion Engineering Steam Generators

Plants: **Type 1:** Calvert Cliffs 1&2, Fort Calhoun; **Type 2:** St. Lucie 2, San Onofre 2 & 3, Waterford 3; **Type 3:** Palisades, Palo Verde 1, 2, & 3.

Based on the design differences in the tube supports of the 12 CE-designed plants, the CE-manufactured steam generators are categorized into three different types: Type 1 - SGs with carbon steel eggcrates and drilled carbon steel plates at upper elevations; Type 2 - SGs with carbon steel eggcrates only; and Type 3 - SGs with stainless steel eggcrates only.

All licensees with CE-designed SGs have agreed with the following conclusions reached by the CEOG about the degradation identified in the GL (Refs. 14-20). All mechanisms recently found in the foreign PWRs are generally not applicable to CE-designed steam generators; the only current applicable one that could have safety significance is flow-assisted corrosion of the peripheral regions of eggcrates at uppermost elevations as recently found at SONGS 3. Further, none of these degradation mechanisms threaten the integrity of the reactor's coolant system pressure boundary nor the heat removal function of the steam generator. The FAC of the peripheral region is primarily the result of secondary fluid-flow redistribution caused by severe bundle fouling of the tubes, exacerbated by using ammonia to control the pH of secondary fluid. Based on operating experience, these steam generators, except those at SONGS, have not encountered a significant amount of internal degradation. Appropriate mitigating action has been taken to minimize the effect of any degradation that has occurred. Plants with stainless steel eggcrates are judged not to be susceptible to FAC degradation.

Based on the licensee submittals, inspection plans for secondary side internal components at CE plants are discussed here. The scope and frequency of inspection may be adjusted based on a site-specific experience and evaluation of the results from other industry inspections. Table 2.3 summarizes the inspection program plan included in licensee submittals as part of the responses to the GL. However, CEOG recommended that owners of SGs with carbon steel eggcrates and severe tube-bundle fouling should inspect peripheral eggcrate locations during each RFO. Preferentially, inspections should be to the hot leg side and include, as a minimum, the uppermost full eggcrate and all tube supports above it. In addition, owners of SGs with severe tube-bundle fouling should make a one-time inspection of the peripheral eggcrate locations.

Table 2.3 Recommended SG Internals Inspection Program for CE SGs

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	ECT for ligament cracking in carbon steel plates in Type 1 plants and for its presence in eggcrates. For Type 2 and 3 plants, perform ECT for the presence of TSPs only
Wrapper drop/cracking	ECT to detect potential tube deformation resulting from misalignment of wrapper. If interference with the sludge lance equipment or deformation of periphery tubes is detected, the lower wrapper support blocks will be visually inspected
Transition cone girth weld	Inspect according to ASME Section XI Inservice Inspection Program requirements for the SG shell
Feedwater nozzle	Inspect according to ASME Section XI Inservice Inspection Program requirements. Loose parts monitoring to detect potential degradation of the FW nozzle
Upper package	Inspection of steam separators and feed-ring equipment. Secondary side visual inspections of feed ring assembly (ring, attachments and nozzles), FW distribution box and thermal liner, upper tube-bundle assembly, cyclone separators, various drain lines and couplings, internal sample lines, internal man-way, Chevron separators, deflection plate, and miscellaneous bolts.

NOTE: All visual inspections involve a Welch Allyn probe, remote camera, or fiber optics.

2.3 Plants with Westinghouse Steam Generators

Westinghouse designed two basic types of SG: feed ring and preheat. Each type is made with carbon steel TSPs and stainless steel TSPs. Thus, the following four categories envelop all W-designed SGs:

(1) Feed ring units with carbon steel TSPs - Models 44, 51, and 51M

(2) Preheat units with carbon steel TSPs - Models D3, D4, and E2-TGX

(3) Preheat units with stainless steel TSPs - Models D5 and E2-THX

(4) Feed ring units with stainless steel TSPs - Models F, 44F, 51F, 54F, and Delta Series

WCAP-15002 (Ref. 21) and WCAP-15031 (Ref. 22) include consensus guidelines for inspecting the SG internals in four groups of W models; specifics about the degradation of SG internal components and the kind of recommended inspections are presented in Tables 2.4 to 2.7. Later, WOG completed an assessment of steam generators which included W models F, 44F, D-series and E2. Final inspection guidelines for these SG models are given in the WCAP-15093 (Ref.23) and WCAP-15104 (Ref. 24) reports. They focus on the types of degradation that each SG model may exhibit during normal service-life. Most of these recommended inspections should be performed each RFO, unless noted otherwise by the owners group recommendations. The scope and frequency of inspections may be adjusted based on site-specific experience and evaluation of industry results.

Typically, most plants undertake eddy current examinations of tubes, FOSARs, sludge lancing/water slapping, and visual examination of SG internals during each RFO. WCAP-15104 makes the following recommendations for licensees for developing their own inspection programs commensurate with their SG models and existing SG inspection and surveillance programs at their plants.

2.3.1 Feed Ring Steam Generators with Carbon Steel Support Plates (Models 44, 51, and 51M)

Plants: Beaver Valley 1&2, Diablo Canyon 1&2, Farley 1&2, Kewaunee, Prairie Island 1&2, Salem 2, Sequoyah 1&2

For this group of SGs, the TSP flow hole/ligaments are susceptible to erosion-corrosion type of degradation. There exists low susceptibility for cracking of wrapper near supports and eventual wrapper drop. Erosion-corrosion in moisture separator and feed ring/J-tubes, and cracking of TSP ligaments and transition cone girth welds have been observed in some SGs. Table 2.4 provides recommended inspection program suggested by the manufacturer.

Table 2.4 Recommended SG Internals Inspection Program for W Feed Ring Models with Carbon Steel Support Plates

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	Establish a baseline employing low-frequency bobbin results from a past or the current outage (Ref. EPRI SG-96-05-003, 5/96). Inspect critical area for TSP cracking in the 3 rows around the periphery and 2 rows around the patch plate region and for ligament erosion-corrosion in the entire tube-bundle (an initial sample of 20% of the tubes is recommended)
Wrapper drop	If interference with the sludge lance equipment is detected, visually inspect the lower wrapper support blocks
Wrapper cracking	Unless there is evidence of wrapper's mis-position or tube damage in the periphery at the first TSP, no inspection is recommended. If detected, visually inspect the lower wrapper's support blocks
Transition cone girth weld	Inspect according to ASME Section XI Inservice Inspection Program requirements for the SG shell
Feedwater nozzle	Inspect according to ASME Section XI Inservice Inspection Program requirements. Monitor loose parts to detect potential degradation of the FW nozzle

SG Components Degradation	Inspection
Upper package	Inspect primary and secondary moisture separators and feed ring equipment (J-tubes, CS feedring adjacent to J-tubes, T-section, reducer, backing ring, and thermal sleeve). A loose part is of primary significance to tube integrity as a result of degradation of these components.

2.3.2 Preheat Steam Generators with Carbon Steel Support Plates (Models D3, D4, and E2-TGX)

Plants: Comanche Peak 1, Shearon Harris, South Texas 1, Watts Bar

For this group of SGs, the moisture separator and the TSP flow hole/ligaments are susceptible to erosion-corrosion. TSP ligaments are also susceptible to cracking. There exist low susceptibility for cracking of the wrapper near supports and eventual wrapper drop, and cracking of transition cone girth welds. Cracking of the waterbox has been observed in some SGs. Table 2.5 provides the recommended inspection program suggested by the manufacturer.

Table 2.5 Recommended SG Internals Inspection Program for W Preheat Models with Carbon Steel Support Plates

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	Establish a baseline employing low-frequency bobbin results from a past or the current outage (Ref. EPRI SG-96-05-003, 5/96). Inspect critical area for TSP cracking in the 3 rows around the periphery and 2 rows around the patch plate region and for ligament erosion-corrosion in the entire tube-bundle (an initial sample of 20% of the tubes is recommended) In-service inspection should be conducted in accordance with Rev. 5 of the EPRI PWR SG Examination Guidelines Models D3 and D4 Eddy current examination employing EPRI-recommended low-frequency bobbin results from a past outage or current outage should establish a base line. If indications are found, their history should be tracked to establish if this is an active degradation mechanism Experience of Model D4 degradation should be considered to be a precursor to any indication of cracking in the D5 SG due to their longer service-life and CS construction Model E2-TGX Eddy current examination employing EPRI recommended low frequency bobbin results from a past outage or current outage should establish a base line. If indications are found, their history should be tracked to establish if

SG Components Degradation	Inspection
	this is an active degradation mechanism
Wrapper drop	If interference with the sludge lance equipment is detected, visually inspect the lower wrapper's support blocks
Wrapper cracking	Unless there is evidence of wrapper's mis-position or tube damage in the periphery at the first TSP, no inspection is recommended. If detected, visually inspect the lower wrapper's support blocks
Transition cone girth weld	Inspect according to ASME Section XI Inservice Inspection Program requirements for the SG shell
Preheater (Model D3)	Inspect integrity of baffle plate by eddy current testing (ECT)
Waterbox (Model D4 & E)	Review ECT data for presence of loose parts in the periphery and T-slot region. If possible, make a baseline visual inspection, with subsequent ones at every fourth RFO (e.g., inspect one SG each RFO, or all four at every fourth RFO)
Upper package	Inspect primary and secondary moisture separators. The significance to tube integrity when these components deteriorate is primarily a loose part. FOSARs should continue. Eddy current inspections of peripheral and T-slot tubes within the preheat region should be made at each scheduled outage.

2.3.3 Preheat Steam Generators with Stainless Steel Support Plates (Models D5 and E2-THX)

Plants: Byron 2, Braidwood 2, Catawba 2, Comanche Peak 2, South Texas 2

For this group of SGs, both the moisture separator and the water box are susceptible to erosion-corrosion type of degradation. There exists low susceptibility for cracking of TSP ligaments, wrapper near supports and eventual wrapper drop, and transition cone girth welds. Table 2.6 provides recommended inspection program suggested by the manufacturer.

Table 2.6 Recommended SG Internals Inspection Program for W Preheat Models with Stainless Steel Support Plates

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	Since the plates are stainless steel and with a quatrefoil broached-hole support design, ECT can not detect TSP cracking. However, it can detect the absence of a TSP. Model D4 would be considered as the precursor to any indication of cracking in D5, and hence no inspection is recommended unless degradation is detected in D4 inspections

SG Components Degradation	Inspection
	Model D5 All models have round tube holes in the baffle plates and round flow-holes. In model D5, flow holes are utilized in flow-slot regions. Inspections are not recommended with regard to the possibility of hole alignment resulting in separated ligaments, unless tube's eddy current inspections indicate a potential separation Model E2-THX Similar ECT techniques should be used as are recommended for TGX for detecting deterioration of ligaments This model has round tube-holes in the baffle plates and round flow-holes. Inspections are not recommended with regard to the possibility of hole alignment resulting in separated ligaments, unless tube eddy current inspections indicate a potential separation
Wrapper drop	If interference with the sludge lance equipment is detected, visually inspect the lower wrapper's support blocks
Wrapper cracking	Unless there is evidence of wrapper's mis-position or tube damage in the periphery at the first TSP, no inspection is recommended. If detected, visually inspect the lower wrapper's support blocks
Transition cone girth weld	Inspect according to ASME Section XI Inservice Inspection Program requirements for the SG shell
Waterbox	Review ECT data for the presence of loose parts in the periphery and T-slot region. If possible, make a baseline visual inspection with subsequent ones at every fourth RFO (e.g., inspect one SG each RFO or all at every fourth RFO)
Upper package	Inspect primary and secondary moisture separators. The significance to tube integrity when these components deteriorate is primarily a loose part. FOSARs should continue. Eddy current inspections of peripheral and T-slot tubes within the preheat region should be made at each scheduled outage.

2.3.4 Feedring Steam Generators with Stainless Steel Support Plates (Models F, 44F, 51F, 54F, and Delta Series)

Plants: Callaway, Cook 2, Indian Point 2&3, Millstone 3, North Anna 1&2, Point Beach 1&2, Robinson 2, Salem 1, Seabrook 1, Summer 1, Surry 1&2, Turkey Point 3&4, Vogtle 1&2, Wolf Creek

For this group of SGs, there exists low susceptibility for cracking of the TSP ligaments and the wrapper near supports (which may lead to wrapper drop). Erosion-corrosion in moisture separator and feed ring/J-tubes, and cracking of transition cone girth welds have been observed in some SGs. Table 2.7 provides the recommended inspection program suggested by the manufacturer.

Table 2.7 Recommended SG Internals Inspection Program for W Feedring Models with Stainless Steel Support Plates

SG Components Degradation	Inspection
Tube support plate ligament erosion/corrosion and cracking	Since the plates are stainless steel and quatrefoil broached hole support design, ECT is not applicable. A sample visual inspection of TSP region is recommended <u>Models F and 44F</u> Due to quatrefoil broached-hole design, ECT is not applicable. For early model F SGs, a sample inspection of patch plate and plug weld regions should be made. For all model F SGs, a sample visual inspection is recommended of the top TSP, tube-lane region (where flow holes are provided instead of elongated slots). Flow holes are used for strengthening the top TSP for U-bend support. If initial drilling produced a separated ligament, the effect on U-bend support should be evaluated If degradation representative of the tube's wear is indicated near TSP elevations, subsequent visual inspections are recommended
Wrapper drop	If interference with the sludge lance equipment is detected, visually inspect the lower wrapper support blocks
Wrapper cracking	Unless there is evidence of wrapper's mis-position or tube damage in the periphery at the first TSP, no inspection is recommended. If detected, visually inspect the lower wrapper's support blocks
Transition cone girth weld	Inspect according to ASME Section XI Inservice Inspection Program requirements for the SG shell
Feedwater Nozzle	Inspect according to ASME Section XI Inservice Inspection Program requirements. Monitor loose parts to detect potential degradation of the FW nozzle
Upper package	Inspect primary and secondary moisture separators and feed ring equipment (J-tubes, CS feedring adjacent to J-tubes, T-section, reducer, backing ring, and thermal sleeve). Inspect replacement SGs with older upper package more frequently. The significance to tube integrity if these components degrade is primarily a loose part. FOSARs should continue

2.4 Summary and Conclusions

All plants indicated in their submittals that some program (formal or informal) for monitoring degradation of SG internals is in place and that inspections are typically carried out at each refueling outage (although not usually for all SGs at each refueling outage). Several plants with a history of problems similar to that described in the GL had already performed, or had plans to perform, comprehensive inspection of their SG internals during the next scheduled refueling outage. Further, several plants had replaced their SGs with new, improved designs. These improved designs included the use of corrosion-resistant materials, and better monitoring techniques which had significantly contributed to industry-wide enhanced management programs for SG internal components.

The existing SG internals inspection programs are plant-specific and generally include the following:

(1) Eddy current examinations of tubes that detect TSP degradation or presence of loose parts.

(2) Visual/video inspections of tubesheets, TSPs, tube bundle, steam drum, feedwater nozzles including thermal liners, feedwater distribution components, waterbox, and moisture separators.

(3) ASME Section XI In-Service Inspection of welds.

(4) FOSAR activities.

(5) Sludge-lancing, water-slapping or -lancing, chemical or pressure pulse cleaning.

From the results presented in the licensees' submittals and owners group assessments, there are no near-term problems nor are there needs for any immediate change in the existing SG internals inspection activities. However, licensees plan to upgrade the existing inspection activities by implementing their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals.

3 EVALUATION OF RESPONSES BY PLANTS WITH BABCOCK & WILCOX STEAM GENERATORS

This section discusses the two groups of plants that have steam generators manufactured by B&W. The first group contains five sites and seven reactor units whose nuclear steam supply systems (NSSS) were designed and supplied by B&W. All of these B&W plants have two Reactor Coolant System loops, each with two Reactor Coolant Pumps, and one once-through steam generator (OTSG). A typical arrangement is shown in Figure 3.1. Thus each unit has two OTSGs. Figure 3.2 shows a diagram of a B&W OTSG.

The second group of plants includes eight sites and nine reactor units. All have replaced their original steam generators with enhanced ones designed and manufactured by B&W International of Canada. Unlike the first group, these replacement steam generators (RSGs) are B&W recirculating steam generators. Figure 3.3 illustrates the RSGs used in U.S. plants. They incorporate design features to mitigate many problems experienced with the original models. Based on the licensee submittals at the time of this review, this report addresses the seven plants (except Braidwood 1 and Cook 1) in this group with RSGs in-service. Table 3.1 below lists all the plants included in these two groups.

Table 3.1 Plants with B&W-Designed Steam Generators

Plants with Once-Through SGs (Model 177)		Plants with Replacement SGs (Model CFR-80)				
Plant Name	**Commercial Start Date**	**Plant Name**	**Commercial Start Date**	**Original SG Models**	**Number of SGs**	**Replacement SG Inservice Date**
ANO 1	12/74	Braidwood 1	7/88	W D4	4	11/98
Crystal River 3	3/77	Byron 1	9/85	W D4	4	2/98
Davis Besse 1	7/78	Catawba 1	6/85	W D3	4	10/96
Oconee 1	7/73	Cook 1	8/75	W 51	4	12/00
Oconee 2	9/74	Ginna	7/70	W 44	2	6/96
Oconee 3	12/74	McGuire 1	12/81	W D2	4	5/97
TMI 1	9/74	McGuire 2	3/84	W D3	4	12/97
Braidwood 1 and Cook 1 GL 97-06 responses are based on their original SG models.		Millstone 2	12/75	CE 67	2	1/93
		St. Lucie 1	12/76	CE 67	2	1/98

The original B&W OTSGs have been in service for over 20 years, the oldest being at Oconee 1. The B&W RSGs presently in service have been used to replace four models of Original Equipment Steam Generators (OESGs). Millstone 2 and St. Lucie 1 replaced CE model 67 SGs; Ginna replaced Westinghouse model 44 SGs; Cook 1 replaced Westinghouse model 51 SGs; and Catawba 1, McGuire 1&2, Braidwood 1, and Byron 1 replaced Westinghouse model D-series SGs. Thirty B&W designed

RSGs are inservice in nine units. Out of the nine units with RSGs, three (i.e., Millstone 2, Ginna, and Catawba 1) have completed first inspections during their first refueling outage (RFO).

The following two sections discuss the results of evaluating the licensee submittals to GL 97-06 for the two groups of plants with B&W steam generators.

3.1 Plants with B&W-Designed Once Through Steam Generators

Each of the seven units in the United States with Babcock & Wilcox (B&W) reactors was originally built with two B&W, model 177, once-through steam generators (OTSGs). These steam generators use straight heat-exchanger tubes with a tubesheet at both the top and bottom of the straight tube-bundle. Primary coolant is pumped through the tubes from the top to bottom of the OTSG. Feedwater (secondary water) enters in the middle of the OTSG and is preheated as it flows down around the shroud. The secondary water then flows up around the tubes, creating a counter-flow heat exchanger, where it is converted to steam. Near the top of the tube-bundle the steam is superheated before it leaves the OTSG.

The OTSG has 15,500 alloy-600 tubes; the tube pattern inside the steam generator is triangular. There are 15 broached, trefoil tube-supports in between the two tubesheets that are made from either carbon or manganese-molybdenum (MnMo) carbon steel. An untubed lane provides access for secondary-side inspections. Two configurations of auxiliary feedwater (AFW) header assemblies are used in the OTSGs. Five plants use an external distribution header mounted outside the OTSG with nozzles penetrating the shell and the shroud. Oconee 3 and Davis Besse 1 originally used an internal distribution header mounted inside the OTSG; this was later replaced with external distribution headers.

SG Internals Degradation Experience and Evaluation

The B&WOG performed safety and susceptibility assessments relative to the design and operating history of the once-through steam generators. These assessments provide reasonable assurance that steam generator tube's integrity and DHR capability are not compromised by degradation of SG internals. The B&W owners group, with technical assistance from Framatome Technologies Inc. (FTI), evaluated all potential internal degradation mechanisms to determine if a formal inspection program is necessary. The FTI report on OTSG Internals Degradation Evaluation (Report No. 77-5003013-00, February 1999) summarizes the method and the findings of this review (Ref. 12). All areas of the OTSG identified as being potentially susceptible to degradation are discussed in the FTI report, along with recommended inspection procedures, frequencies, and disposition criteria.

The approach used included evaluations of degradation modes for structural components, chemical cleaning, and thermal-hydraulics factors associated with the OTSG design, manufacturing and operations. Degradation at EdF, operating experience in U.S. plants, and indications of damage or susceptibility to other potential damage mechanisms that have not yet been seen by the industry, or that may be unique to the OTSGs were considered. Chemistry data from licensees to determine the chemistry's impact on flow-accelerated corrosion (FAC) and other damage mechanisms were part of this evaluation. Finally, the report contains FTI's recommendations for inspecting SG internals to monitor any future potential degradation.

The scope of the FTI's evaluation encompassed all components of OTSG internals including tubes and shell. These tubes and shell are regularly inspected as part of the pressure boundary, and any degradation is addressed by the OTSG tube-integrity program. The shell vessel welds are considered in the plant in-service inspection (ISI) program. Other SG internal components include 24" steam outlet nozzle, baffle plate (shroud), tubesheets, tube support plates, feedwater header/spray nozzles, auxiliary feedwater nozzle, all kinds of small pipes and fittings, and other miscellaneous parts. Almost all internal components are made of either carbon steel or forged carbon steel. Notable exceptions are the SG tubes which are made of Alloy 600, and the tubesheets which are made Mn-Mo carbon steel.

Some peripheral tubes were damaged at Davis Besse 1 in 1981 and Oconee 3 in 1982 and leaked. This damage was caused by movements of the AFW internal headers and the brackets attaching these headers to the wrapper during operation. The AFW internal headers were subsequently stabilized, and functionally replaced by external headers at these two plants. No movements or new indications of tube degradation have been observed at either plant since the internal AFW supply headers were stabilized. The original internal headers were left inside the steam generators; eddy current examinations are performed at each refueling outage to evaluate the status of peripheral tubes. The internal header also is visually inspected for movement inside the steam generators. So far, no further evidence of movement or degradation of the internal AFW header or peripheral tubes has been noted. The internal header is visually inspected at Davis Besse 1 every 10 years as part of the plant technical specification requirements. Oconee 3 inspects the internal AFW header as part of a commitment made to the NRC in 1982. In addition, visual inspections of these internal headers and 100% eddy current bobbin coil inspections of the peripheral OTSG tubes have been conducted since 1995. No new degradation of the SG internals have been noted. Another visual inspection of the internal header is planned for the 3rd 10-year ISI schedule.

Based on the operating experience data, a significant number of secondary side inspections have been made at each of the B&WOG member plants, spanning from pre-service to 17 effective full-power years (EFPYs). These inspections have included all 15 TSPs, the upper and lower tubesheets, and one recent inspection of the upper wrapper welds at Oconee 1 (with the oldest SGs). Many were carried out in conjunction with an SG cleaning process, tube repairs, or other maintenance work. The SG cleaning process included water slap (WS), pressure pulse (PP), sludge lancing (SL), and chemical cleaning (CC).

During each secondary side cleaning, visual inspections were made during both pre-cleaning and post-cleaning typically on the 3rd through the 6th TSPs, and on the 9th and 10th TSPs. In all cases, pre-cleaning inspection revealed some deposits and post-cleaning inspection verified that all were removed. In recent years, fiberscopic inspections of the secondary side have been conducted following tube-pull operations. Since tubes are typically pulled from the lower tubesheet, most inspections encompassed the lower tubesheet through either the 7th, 8th, or 9th TSPs. In one case, the tube hole was inspected from the upper tube end to the 11th TSP. None of these inspections revealed any damage to, or degradation of the TSPs.

Oconee 2 experienced higher corrosion rates during chemical cleaning than at the other three plants, possibly due to higher concentration of magnetite in solution due to heavier deposit loading in the SGs. In response, FTI made an evaluation in 1996 to predict tube wear, TSP land wear, and operational corrosion rate as a function of increasing diametrical clearance due to chemical cleaning, operational corrosion, and through operational fretting-wear. The effects of increasing the gap on tube wear-rates and the margin to fluid elastic instability were evaluated using a combination of analytical and empirical techniques. The critical diametrical clearance was determined from the initiation of flow-induced vibration or fluid-elastic instability. Since chemical cleaning removes a small amount of base metal from the surface of each TSP and will affect the land areas of the broached tubes, the FTI evaluation determined that the diametrical clearance for up to six chemical cleanings would have no significant effects on fluid-elastic instability nor random turbulent response. Although corrosion allowances were not exceeded at Oconee 2, an increase in the corrosion allowance for the TSP land is necessary should a second cleaning be required.

In 1997, the oldest OTSG at Oconee 1 was visually inspected for upper wrapper welds after 17.7 EFPYs. Two of the main feedwater nozzles were removed to obtained access and to examine the upper wrapper welds from below. No damage was found.

FTI assessed other potential degradation mechanisms of OTSGs' internals that have not yet been observed in operating plants, and were not considered in the original design.

(1) At Oconee 1 in 1979, there was an unusual pattern of tube dings at the 9th and 10th TSP level. Those dings at the 9th TSP appear to be in line with the wedge blocks, and at the 10th, they are offset slightly clockwise from the alignment pins and wedge blocks. The actual cause of these dings is unknown. However, recent inspections do not show any appreciable increase in the number of tubes affected nor growth in the magnitude of the dings. FTI recommends monitoring of these affected regions during future inspections.

(2) The manway covers in the TSPs are made of the same material as the TSPs (SA-515, Gr. 70 CS or SA 212-B CS). They are assembled using six 1.27 cm (½ inch) cap-screws that are tack-welded at final assembly. Should these covers become loose, they could cause wear which would be detected by eddy current inspection of the tubes.

(3) There are four 1.27 cm (½ inch) hex bolts in the shroud access cover (elliptical). On all of the OTSGs except Crystal River 3, the bolts are tack-welded. Since there are no loads that would directly cause these bolts to back out at Crystal River, no potential damage mechanisms are associated with the shroud cover.

(4) The tie rod to nut-lock welds in an OTSG serve the same function as in the EdF SGs. No structural mechanisms in the OTSG design were identified that would contribute to failure of the tie-rod to lock-nut weld.

3.1.1 Susceptibility of the OTSG Relative to the EdF and SONGS Experience

All seven OTSG plants joined with the B&W Owners Group (B&WOG) to assess the susceptibility to tube damage and loss of decay heat removal (DHR) capability due to deterioration of secondary-side components. EPRI's report, GC-109558, "*Steam Generator Internals Degradation: Modes of Degradation Detected in EDF Units,*" (Ref. 6) was used to evaluate the causal factors of the degradation in the EdF units. From it the B&WOG gained insights into the applicability of the French experience to their steam generator designs and operating history. In developing the susceptibility assessment, other attributes considered were design factors, fabrication and manufacturing techniques, and plant's operating history, including chemistry and related damage, such as denting. In addition, the B&WOG compiled and assessed information on their respective eddy current examinations, visual, video and other pertinent non-destructive examinations (NDE) as part of the in-service inspection (ISI) experience to improve their evaluations of vulnerability of OTSGs to internals degradation.

The B&WOG member utilities have assembled and summarized design documentation relating to SG secondary side components. Existing analyses on possible degradation mechanisms were collected. Also, recent internal damage at the San Onofre Nuclear Generating Station (SONGS) was assessed for the OTSG design. The internals of the OTSGs were evaluated for each degradation mode experienced at EdF plants and at SONGS; this included structural mechanisms, chemistry, and thermal-hydraulic factors. These assessments are discussed here.

(1) Erosion of the top TSP due to improper placement of hoses during chemical cleaning:

The following provisions are included in the chemical cleaning process for OTSGs: (a) any residual solvent must decompose and volatilize without deleterious effects to structural materials at operating temperatures and pressures, (b) the solvent has to be compatible with both carbon steel and Alloy 600, (c) the solvent vapors can not cause a corrosive environment, should the uninhibited vapors condense in the upper tubesheet's crevice regions during cleaning, and (d) solvent velocities and solvent impingement have to be such that erosion of structural materials does not occur. Tests performed by B&W confirmed the effectiveness and non-aggressiveness of the selected solvent and process. B&W provided a Chemical Cleaning Guide Specification with the OTSGs.

In 1978, EPRI initiated a program to qualify solvents and procedures for use in SGs. The fill-soak-drain method was recommended since it provided a means of replenishing the solvent with the assurance that all portions of the SG that were being cleaned would periodically see fresh solvent. Areas that were identified as sensitive to dimensional changes during chemical cleaning are TSPs, TSP wedges, spacer rods, spacer sleeves, alignment pins, feedwater headers, partial-penetration attachment welds, shell, and tubesheets.

Four (ANO-1, Oconee 1 & 2, and TMI-1) of the seven plants have had their steam generators chemically cleaned using an EPRI-qualified cleaning solvent. This solvent differs from that used by EdF. Both Oconee 1 and 2 were cleaned more than 7 EFPYs ago; no adverse conditions have been observed by eddy current or visual inspections since that time.

(2) Ligament cracking of carbon steel with drilled hole TSPs due to mechanical loads during manufacturing, shipping, or early operations:

The in-plane TSP loads in an OTSG are produced by the lateral restraint from eight alignment pins evenly spaced around the shroud at each TSP. These pins are threaded to the shroud on one end, while the other ends are contacted with the shell (at room temperature). Wedge blocks near the alignment pins provide radial connections between the shroud and the TSP. Two keys (block-welded to the shroud with a notch cut in the outer rim of the associated TSP) are located 180 degrees apart, and serve for initial alignment during fabrication. The TSP man-way is secured to the TSP with threaded fasteners, as opposed to the plug welds in the EdF SGs.

The stress analysis of OTSG internals revealed that the loads on the alignment pins due to seismic and differential thermal expansion between the internals and shell are relatively small during plant operation, and the design margins are large for the components that transmit these loads. Lifting loads during fabrication and thermal stresses during stress relief were carefully monitored and kept within the predetermined limits. During transportation, the movements or vibration of the SG unit were monitored to detect any significant shock forces. Final inspection of OTSG internals indicated that there was no damage similar to the degradation seen in the EdF plants.

The B&W OTSGs have broached-hole TSPs and are made of either carbon steel or MnMo carbon steel. Since no eddy current techniques (ECT) are qualified to detect degradation in broached hole design TSPs, ECT was used only to verify that the TSPs are located properly. Numerous visual inspections were performed at all seven plants over the last 25 years, and no deterioration of TSPs was observed in any steam generator.

(3) *FAC-induced thinning of the top TSP's periphery due to ammonia water chemistry:*

FAC was detected in EdF SGs with ammonia water chemistry, but not in those with morpholine water chemistry. The thinning due to FAC was aggravated by the lower pH of the ammoniated water. Ligament thinning at EdF units was seen in the TSP 8 regions, with velocities of about 7 m/s and quality of 33%, but not in adjacent regions with somewhat lower velocities and qualities. This finding indicates that there is a relatively sharp threshold for triggering FAC at the operating temperature (523° F), pH, and electrochemical potential involved. Also, EdF stated that high hydrazine concentration (>100 ppb) might accelerate FAC. However, this was not experienced in Japanese plants where hydrazine concentrations of 100 to 600 ppb have been used in the feedwater since 1984.

All seven OTSG plants have operated on All Volatile Treatment (AVT) feedwater chemistry. Early in the plant's life, hydrazine for oxygen control and ammonia for pH control were used. Later, the pH control additive was switched to morpholine (an amine) to reduce FAC in the balance-of-plant systems' piping where such problems were observed. Based on NDE inspections, tube-pull evaluations, and the secondary side inspections, FAC has not been noted on the top TSP of any SGs in U.S. plants.

(4) *Wrapper-drop due to fatigue failure of supports:*

The OTSG shroud (wrapper) consists of two shells, one upper and one lower, separated by a small gap. The upper part is supported by a flange welded to the bottom of the upper shroud and to the shell. The lower shroud is welded to a flange that, in turn, is bolted to the lower tubesheet.

B&W indicated that their analysis demonstrated adequate structural strength for seismic and thermal loads due to differential expansion loads between the shroud and the shell. This design is very different from that in EdF plants. Recently, the upper wrapper assembly, welds, and internal components in the vicinity of the welds of the oldest OTSGs at Oconee 1 were visually inspected. There were no signs of wrapper degradation, shift, or drop.

(5) Fatigue cracks from support blocks due to flow-induced vibration of wrapper:

Alignment pins at TSP elevations prevent significant radial motion due to interference or small gaps between the pin and shell. Thus, large amplitude vibration is prevented, and fatigue cracks or wear due to flow-induced vibration are not expected to occur at these locations.

As noted above, inspections of the secondary side at Oconee 1 revealed no degradation or crack on the support blocks.

(6) TSP wedge block cracking:

Fabrication, thermal stress relief operations, and shipping of the OTSGs to plant sites were carefully monitored to prevent excessive mechanical and/or thermal loads. The TSP stress analysis for SGs lying on their side during shipping, and subsequent inspections of SG internals have assured that there was no damage similar to the degradation experienced at the EdF plants.

As noted above, inspections of the secondary side at Oconee 1 found no deterioration or cracking of the support welds.

(7) Eggcrate support degradation at SONGS due to FAC associated with fouling:

There are few design and performance similarities between the CE SGs at SONGS and the OTSGs. Suspected contributing factors to FAC at SONGS are ammonia chemistry and SG fouling due to iron loading. FTI's assessment of fouling conditions in OTSGs considering water chemistry and thermo-hydraulics indicates that there should not be any problem, even with 90% of the flow area blocked by fouling during normal operation. The maximum estimated TSP FAC for an OTSG that has not been chemically cleaned is 13.4 mils for Oconee 3 after 17.8 EFPYs.

FTI evaluated the susceptibility of the OTSG TSP to FAC during operation. FAC is a function of, and is limited by, the solubility of magnetite in water and the rate at which ferrous ions are transported from the metal's surface. Solubility also is a function of temperature, pH, and hydrogen concentration. In recirculating SGs, quality increases as the water/steam mixture rises in the tube-bundle (50% or more in fouled units), somewhat faster in the hot leg than in the cold leg. In an OTSG, saturated liquid enters the bottom of the straight tube-bundle and is heated through the entire quality range to 100% by the 7th TSP; it leaves the OTSG as superheated steam above the 15th TSP. OTSGs now use morpholine (or amine) water to control pH. The pH will vary depending on the distribution of the amine between the steam and the liquid, and the ionization of amine. Distribution varies with the concentration of amine, temperature, and quality; while ionization varies with amine concentration and temperature.

FTI analyzed all seven plants with OTSGs for normal operation and a 90% blocked flow-area due to fouling. For the latter, the maximum estimated TSP FAC is 14 mils in the tube region at Oconee 1 after 18.7 EFPYs. Typically, the OTSGs are chemically cleaned when 50% of the flow area is blocked by fouling. The geometry of the broached hole in the TSP is such that the flow that might cause FAC is in the broached opening. Any metal loss would be from the broached side of the opening, since the other side is the land area in contact with the tube where there is essentially no flow. Thus, corrosion of the land area and broached area may occur during chemical cleaning, while the broached area will become corroded where there is significant flow.

In summary, these assessments provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

3.1.2 Responses to NRC's Generic Letter 97-06

At the time of this review, no OTSG plant had a formal inspection program to detect degradation of the internals of their steam generators. All plants have been operating since their commercial start-dates during seventies, and their informal inspections of the secondary side components during sludge lancing, chemical cleaning, water slapping, or tube repair/maintenance outages have not shown degradation of any internal component that may challenge the tube's integrity. The only internals degradation found was to the internal AFW headers in Davis Besse and Oconee 3. After replacing them with external headers, and abandoning the internal headers inside the SGs in the early eighties, these two licensees have committed to the NRC (Davis Besse via technical specifications, and Oconee 3 as part of a 1982 commitment to NRC) to inspect for any future damage caused by the movement of the abandoned AFW internal headers.

All plant submittals addressed the intent of GL 97-06. Plant-specific data on past inspection experiences were submitted in one table as part of the B&WOG evaluation. Details on the specific type of inspections (e.g., using ECT or visual/video camera), internal components inspected, the results, and the disposition of findings were generally not provided.

All plants have been inspected during maintenance or refueling outages. The scope of most inspections includes the nozzles of the main feedwater (MFW), auxiliary feedwater (AFW), and emergency feedwater (EFW), the upper and lower tubesheets, and several intermediate TSPs. Steam generators at ANO-1, Oconee 1&2, and TMI-1 were chemically cleaned once, while those at Crystal River 3 underwent sludge lancing and water slapping. ANO-1 steam generators have not been inspected for a long period (1A since 1990 and 1B since 1981), while Davis Besse units were inspected three times during the last 8 years.

Table 3.2 summarizes the inspection findings from all plants in this group based on information from the licensee's responses to the GL. Since OTSGs have broached-hole tube supports, the eddy current technique is not effective in detecting cracks in tube supports. However, each plant typically performs 100% bobbin coil inspections on SG tubes during each RFO to detect any absence of the tube support. ANO 1, Crystal River 3, and TMI 1 have not mentioned such inspections in their submittals, while the other four plants indicated that they routinely perform them on their SG tubes.

Table 3.2 Plant-specific SG Inspections for B&W OTSGs

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
ANO 1	Not stated	-----	During maintenance outages	No degradation noted	SG 1A internals was inspected 4 times, the last being in 1990; SG 1B internals inspected once in 1981. Deposits were noted on tubes and TSPs before cleaning and none afterwards
CR 3	Not stated	-----	During maintenance outages. Used remote camera once 4/96	No degradation noted	Both SGs inspected almost every RFO. Since their initial operation SG 3A has been inspected six times and SG 3B seven times
DB 1	Performed on periphery tubes at each RFO (TS)	No damage noted since 1981	Visual inspection each 10 yr per TS	MFW nozzle replaced in 1993. No deg. noted	No movement of the abandoned internal AFW header was noted. No cleaning activities reported
ONS 1	100% bobbin coil exam. during last RFO (10/97)	No missing TSPs noted	During maintenance outages	No degradation noted	Both inspected regularly. Recent inspection of the wrapper welds indicated no degradation. No shifting or edge wear on wrappers was noted
ONS 2	100% bobbin coil exam. during last RFO	No missing TSPs noted	During maintenance outages	No degradation noted	Both SG internals inspected regularly but less frequently than unit 1
ONS 3	100% bobbin coil exam. during last RFO. Performed on periphery tubes at each RFO since 1995	No missing TSPs noted. No damage on periphery tubes noted	Visual inspection each 10 yr per ISI schedule	No degradation noted	No movement of the abandoned internal AFW header was noted
TMI 1	Not stated	-----	Visual inspections.	EFW and MFW nozzles	Deposits were noted on tubes and TSPs before cleaning and none

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
			During 1/87, used video camera	replaced. No other degradation noted	afterwards

3.1.3 Summary and Conclusions

Past inspections showed no degradation of the OTSG internals, except for the internal AFW headers at Davis Besse 1 and Oconee 3, which were stabilized and functionally replaced with external AFW headers. The structural evaluation of SG internals relative to EdF and SONGS experience showed that OTSG internals are not susceptible to the same types of degradation.

Each licensee indicated that they have no formal inspection program to detect degradation of SG internals. However, OTSGs at each plant have undergone inspections and cleaning. During this work, some licensees inspected other secondary side components and found no notable degradation.

The B&WOG, with assistance from Framatome Technologies Inc. (FTI), assessed the effects on the OTSG design of various causal factors identified by the EdF units and by SONGS. Based on the recommendations in the FTI report, each licensee will evaluate the need for developing a comprehensive formal inspection program to monitor the degradation of secondary side components, commensurate with existing programs (e.g., ASME Section XI ISI program, each RFO inspections, prior NRC commitments, SG cleaning schedules).

From the results in the FTI report, it is concluded that no additional short-term inspections of the OTSG internals are required; however, guidelines were recommended for inspecting and documenting the condition of the OTSG internals in the future.

FTI recommends pre-cleaning and post-cleaning visual inspections of OTSG internals and fiberscopic examination of the secondary side in all tube-pull operations. The conditions noted should be properly documented to assess the scope of future inspections. Assessments of the cause of the damage at EdF provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

Steam generator internals in each plant in this group, except ANO SG 1B, Davis Besse SGs 1A & 1B, were inspected more than 3 times during their operating lifetime. While the inspections were not comprehensive nor formalized, the results were good, showing no degradation.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

3.2 Plants with B&W-Designed Replacement Steam Generators

At the time of this review, seven plants had replaced their original steam generators with the enhanced recirculating SGs manufactured and supplied by B&W International of Canada (Table 3.1). Later, Braidwood 1 replaced its Westinghouse SGs during November 1998, and Cook 1 replaced its Westinghouse SGs with B&W RSGs in December 2000. Because of this, Cook 1 submitted its GL responses as one of the Westinghouse SG groups. However, Braidwood 1 submitted its GL responses as one of the B&W RSGs. Both these plants included their SG experiences based on their original Westinghouse SG models. The new RSGs were inspected at various times during manufacture and installation, including after their final positioning in each plant. In addition, SGs at Millstone 2, Ginna, and Catawba 1 have completed their first fuel cycle of operation and the tubing was surveyed via ECT examinations, and the upper-bundle and tubesheet regions visually or by video camera.

In general, these B&W RSGs differ in size since they are replacements for units of a different original equipment manufacture (OEM). However, they are identical in concept and in almost all construction materials, including the critically important tubing and tube supports.

The tube supports are made with a 410S stainless steel lattice-bar configuration in contrast to the OEM's carbon steel drilled-hole plates in Westinghouse SGs, or eggcrate supports in CE units. U-bend supports are made of 410S stainless steel flat-bars. The bundle wrapper is supported to the main shell by robust lugs with full penetration welds at the lower end, and by radial pins at various tube support elevations along the wrapper's height. These lugs and pins, along with the tube supports, are arranged to accommodate thermal motions during operation and accidents, as was verified. Thermal loads during manufacturing do not apply since all needed (lower shell) post-weld heat treatment is performed before installing the internals. No post-weld heat treatment of the full vessel is performed.

Several design improvements in the RSGs by BWI address a number of SG internals degradation. Tube to tubesheet crevice IGA is avoided by selection and control of the tube alloy and development and implementation of the tube expansion tooling and procedures which minimize the crevice at the tubesheet secondary face. Tube to tubesheet crevice and primary side stress corrosion cracking is avoided by using tube expansion techniques which minimizes residual stresses. Tube sensitization is avoided by stress relieving the pressure boundary of SG. The tubesheet sludge pipe is minimized through achievement of a high circulation ratio, creating high volume cross flow, high capacity blowdown capability, water chemistry limits, and provision of multiple access ports for sludge lancing. Tube support crud accumulation increases the pressure drop across tube supports through the use of "open-flow" lattice grids. Denting at tube support locations is precluded by open-flow lattice grid supports. Tube vibration fretting wear at lattice grid and U-bend supports is avoided by maintaining optimum tube-to-support contact/clearance, installing U-bend supports, and selecting tube support material that resists wear with Inconel 690 interface. U-bend cracking of inner row tubes is avoided by using large minimum radius bends and application stress relief in the tightest bends.

SG Internals Degradation Experience and Evaluation

These B&W RSGs are inspected during and after manufacture, in-situ before operation (typically in the U-bend region when temporary restraints are removed and inspections made for foreign objects), and after one fuel cycle. Very extensive inspections are performed of the tube supports at several locations, of the wrapper assembly, and in the proximity of peripheral tubes. These inspections are made during and after manufacture, and have shown no degradation in these areas. After removing the temporary U-bend restraints, and installing the SGs in an upright position, the U-bend region and the tubesheet annulus region are inspected for foreign objects. Finally, the SGs at Millstone 2 (10/94), Ginna (10/97), and Catawba 1 (12/97) were inspected after they completed their first fuel cycles. These inspections included ECT examinations, visual inspections of the secondary side tubesheets, and of the U-bend/steam drum region. All three upper vessel inspections were similar and took the same approach, including inspecting a comprehensive list of internal components. Inspections were visual, by direct access, by video camera, or by flexible video probe.

B&W RSGs are uniquely vulnerable to positioning of the U-bend components which could cause contact between peripheral tubes. The U-bend structure, which is free to move with the U-bend during operating transients, is supported by the peripheral tubes by "L" and "J" shaped elements called J-tabs. It was determined that the positioning of some of the J-tabs during manufacture may cause contact between certain pairs of vertically adjacent peripheral tube U-bends. It was confirmed that peripheral tubes in contact during SG operation may be subject to flow-induced vibration fretting wear at their point of contact. However, based on further assessment, B&W stated that fretting wear will not result in unacceptable tube-wall reduction over a normal 40- or 60-year operating life. Another mechanism assessed relates to build up of deposition of corrosion products on the tubes and the potential for bridging of deposits between nearby tubes. Assuming a minimum gap and no vibratory contact, bridging could occur in approximately 10 years. Based on corrosion studies on thermally treated alloy 690 tubing, the B&W OG concluded that no additional damage will result from bridging in the U-bends.

Inspections conducted at three plants have indicated that unfavorable proximity exists (less than desired clearance or possible contact) for a few tubes on several RSGs. Therefore, monitoring the proximity of tubes in this region during subsequent inspections should be performed until the effects of this degradation mechanism on the tube's integrity is better understood. The routine ongoing outage cycle inspections by eddy current tests and secondary side visual inspections can be used.

3.2.1 Susceptibility of B&W RSGs Relative to EdF and SONGS Experience

Seven plants, except Braidwood 1 and Cook 1, with inservice B&W RSGs at the time of this review submitted the assessment findings reported in the B&W report BWC-TR-98-03, Rev. 1, 3/18/98 (Ref. 13), on the susceptibility of tube damage or loss of DHR capability due to secondary side component degradation. The degradation mechanisms described in GL 97-06 are all related to tube support structures or wrappers. The RSG designs all use wrappers with lower restraint-lugs, radial shroud pins and upper slip joint-rings. Also, all RSG designs contain lattice grid tube support structures and a flat-bar U-bend restraint system. These supports restrict flow-induced vibration of tubing and provide structural support for lateral tube bundle loads such as those originating during seismic events. Material qualification for tubing and tube supports includes identifying corrosion allowances for structural analysis, including the effects of general corrosion, flow-assisted corrosion, and chemical cleaning allowances. Also, fretting wear of 410S stainless steel supports and alloy 690 tubing was quantified under typical PWR water conditions.

The B&W report BWC-TR-98-03 (Ref. 13) assesses the potential degradation mechanisms described in GL 97-06. It discusses the major design differences between the cited units and the RSGs and then evaluates whether a similar condition could occur, even though the exact condition may not be relevant. In addition, the report described the U-bend support's positioning mechanism and the resultant effect on inter-tube spacing between certain peripheral, vertically adjacent tubes. This configuration is unique to these RSGs, and was discovered during recent inspections of the tube bundle assembly.

(1) *Erosion of the top TSP due to improper placement of hoses during chemical cleaning:*

Steam generators at all seven plants presently have not undergone chemical cleaning. Also, their materials and designs were pre-qualified for multiple chemical cleanings in the future.

(2) *Ligament cracking of carbon steel with drilled hole TSPs due to mechanical loads during manufacturing, shipping, or early operations:*

RSG TSPs are lattice bar type and not susceptible to ligament cracking. The tube bundles, tube supports, wrapper and related structures are installed after heat treatment of the lower vessel, thereby avoiding high thermal stresses during manufacturing. The shell closure weld, which is performed after tubing and is located at the conical shell, is carefully isolated from internal components and carefully heat treated afterwards. Local flexibilities within the wrapper design accommodate differential thermal expansions during operating transients.

(3) *FAC-induced thinning of the top TSP periphery due to ammonia water chemistry:*

The 410S stainless steel material is conditioned to resist corrosion while providing structural strength.

(4) *Wrapper-drop due to fatigue failure of supports:*

Wrapper support lugs are installed after thermal treatment of the vessel. Robust shell lugs with full penetration welds support the lower edge of the wrapper, and accommodate radial/vertical wrapper growth versus shell growth during operation by providing the necessary flexibility.

(5) *Fatigue cracks from support blocks due to flow-induced vibration of wrapper:*

Anti-vibration support at numerous points (including each of the fixed lower shroud lugs and by the many levels of wrapper (to shell) lateral support pins) limit the wrapper's vibratory motion. Also, the lattice-grid support ring to the wrapper wedge points provide additional restraint.

(6) *TSP wedge block cracking:*

The stresses and displacements calculated for the lattice grids, shroud, and related support components from thermal interactions and flow-loading are safely below design allowable limits. Their basic design readily accommodates thermal interactions during normal operation. This particular degradation mechanism is caused by the same loads which cause the ligament cracking of TSPs, whose resolution is addressed in item 2, above.

(7) *Degradation of Eggcrate support at SONGS due to FAC associated with fouling:*

Lattice bars are made out of 410S stainless steel, which is resistant to flow and corrosion effects.

In summary, these assessments provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

3.2.2 Responses to NRC's Generic Letter 97-06

Byron 1 and Braidwood 1 have a formal, comprehensive inspection program for their older SGs, and the utility indicated that a similar program for the new BWI SGs will be developed for both in accordance to NEI 97-06 guidelines. The remaining RSG plants, excluding Cook 1, do not have a formal inspection program to detect degradation of internals of their steam generators. However, plants completing their first operating cycle have been inspected using the vendors's recommendations. The inspection program as outlined in the technical report BWC-TR-98-03, Rev.1, 3/18/98 is comprehensive, and includes almost all internal components important to maintaining the tube's integrity and SG's DHR capability (see Section 2.2.1.2, Table 2.1).

All plant submittals addressed the intent of the GL 97-06 request for information. Details on the specific types of inspections (e.g., use of ECT or visual/video camera), internal components inspected, the inspection results, and the disposition of findings were generally not provided.

Since the original seven plants and Braidwood 1 have replaced their original steam generators with the B&W RSGs, most have not developed a comprehensive formal inspection program involving the internal components and degradation mechanisms for the replacement RSGs. Some have not had their SGs installed long enough to have done an inservice inspection. Table 3.3 summarizes the inspection results submitted by all plants in this group in response to GL 97-06. Data relating to their original SG was submitted by Byron 1 and St. Lucie 1; this historical information may be useful to the NRC, but is not discussed here.

Of the original seven units with B&W RSGs, four (Byron, McGuire 1 & 2, and St. Lucie) installed their new SGs in 1997, and thus, have not yet had an inservice inspection. Inspections were made at the first refueling outages at Millstone 2, Catawba 1, and Ginna. All units generally showed very good results, but identified some tube proximity in the U-bend region. Millstone 2 also found minor indications of degradation, such as pitting at the bottom of the steam separators, and discoloration of feedwater rings and the shroud cones caused by oxide films. Braidwood 1 replaced its SGs in November 1998 and Cook 1 replaced its SGs in December 2000.

Table 3.3 Plant-specific SG Inspections for B&W RSGs

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Braidwood 1	Braidwood 1, Byron 1, and St. Lucie 1 submitted inspection data relating to their original SG (now replaced). This information may be useful to the NRC for historical purposes, but is not discussed here.				Braidwood (Fall 98) and Byron (Fall 97) replaced the original W SGs with B&W RSGs. The new SGs have not been inspected.
Byron 1	Braidwood 1, Byron 1, and St. Lucie 1 submitted inspection data relating to their original SG (now replaced). This information may be useful to the NRC for historical purposes, but is not discussed here.				Braidwood and Byron replaced the original W SGs with B&W RSGs. The new SGs have not been inspected.
Catawba 1	First ECT inspection during 11/97	Tube proximity was observed on RSGs.	Visual and video inspections during 11/97	No degradation noted	The full 11/97 RSG inspection report was not provided.
Ginna	First ECT inspection during 9/97	Tube proximity was observed on RSGs.	Visual and video inspections during 9/97	No degradation noted	Based on the 9/97 RSG inspections, the licensee is developing a comprehensive inspection program.
McGuire 1	States will use ECT for detecting TSP presence	-----	Pre-service visual and video inspections	No degradation noted	Original SGs replaced with B&W RSGs in 3/97. They have are not been inspected since in operation.
McGuire 2	states will use ECT for detecting TSP presence	-----	Pre-service visual and video inspections	No degradation noted	Original SGs replaced with B&W RSGs in 12/97. They have not been inspected since in operation.
Millstone 2	First ECT inspection during 10/94	Tube proximity was observed on RSGs.	Visual and video inspections during 10/94	Some minor indications of degradation noted	The full 10/94 RSG inspection report was not provided.

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
St. Lucie 1	Braidwood 1, Byron 1, and St. Lucie 1 submitted inspection data relating to their original SG (now replaced). This information may be useful to NRC for historical purposes, but is not discussed here.				St. Lucie replaced the original CE SGs in 12/97 with B&W RSGs. The new SGs have not been inspected.

The inspection program in the B&W technical report is very comprehensive, and includes all SG internal components that are susceptible to degradation. Although there is no specific information on the frequency of inspections, it notes that after the first outage inspection, the frequency and the extent of subsequent ones will be reassessed by the licensee, based on experiences from their own RSGs, and those from other plants.

3.2.3 Summary and Conclusions

All 30 steam generators in this group of nine plants were installed during the last ten years. Braidwood 1 replaced its 4 SGs in November 1998 and Cook 1 replaced its SGs in December 2000. Three plants with eight SGs in total have completed an operating cycle and were inspected during their first refueling outages. No significant degradation was noted in any internal components, except the tube proximity problem in the U-bend region. That problem is still within the design tolerance limits. However, future inspection of these tubes is warranted and is planned by the licensees. Four other plants had their SGs replaced in 1997, Braidwood 1 in 1998, and Cook 1 in 2000; and they all have not completed their first operating cycle. For the near-term, based on the inspection findings at all B&W RSGs, it is proper to assume that no change is necessary in current plant practices.

Based on the operating experience of these newly designed SGs, the support plate wastage due to chemical cleaning is not currently relevant as none of these units have been chemically cleaned. The cracking of tube support plate ligaments is also not directly relevant because tube supports are lattice bar type rather than drilled plates. The 410S stainless steel material for the TSPs provides corrosion resistance as well as structural strength. Wrapper support lugs are with full penetration welds to support the lower edge of the wrapper and the wrapper design accommodate radial/vertical shell growth during operation by providing the necessary wrapper flexibility. The wrapper vibration is avoided by providing anti-vibration support at numerous points including each of the fixed lower shroud lugs and by many levels of wrapper (to shell) lateral support pins. Finally, degradation of eggcrate supports due to flow/corrosion effects is addressed by the selection of 410S stainless steel for the lattice bars.

During SG internal inspections in three plants after their first service period, it was determined that positioning of the U-bend support components could result in contact between peripheral tubes. The routine ongoing outage cycle inspections (by eddy current test and/or secondary side visual) will monitor the condition over time. No evidence of degradation in the steam drum, upper bundle (U-bend) and tubesheet regions was observed.

With the exception of Byron 1 and Braidwood 1, none of these plants has established a formal SG secondary side inspection program. However, the current program at Byron 1 and Braidwood 1 correspond to that of the previous SG model. For the new BWI SGs, it may be necessary to modify the existing program. Over time, visual inspections similar to those already completed (as well as ECT inspection) should be performed to confirm the continued integrity of the SG internal components.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

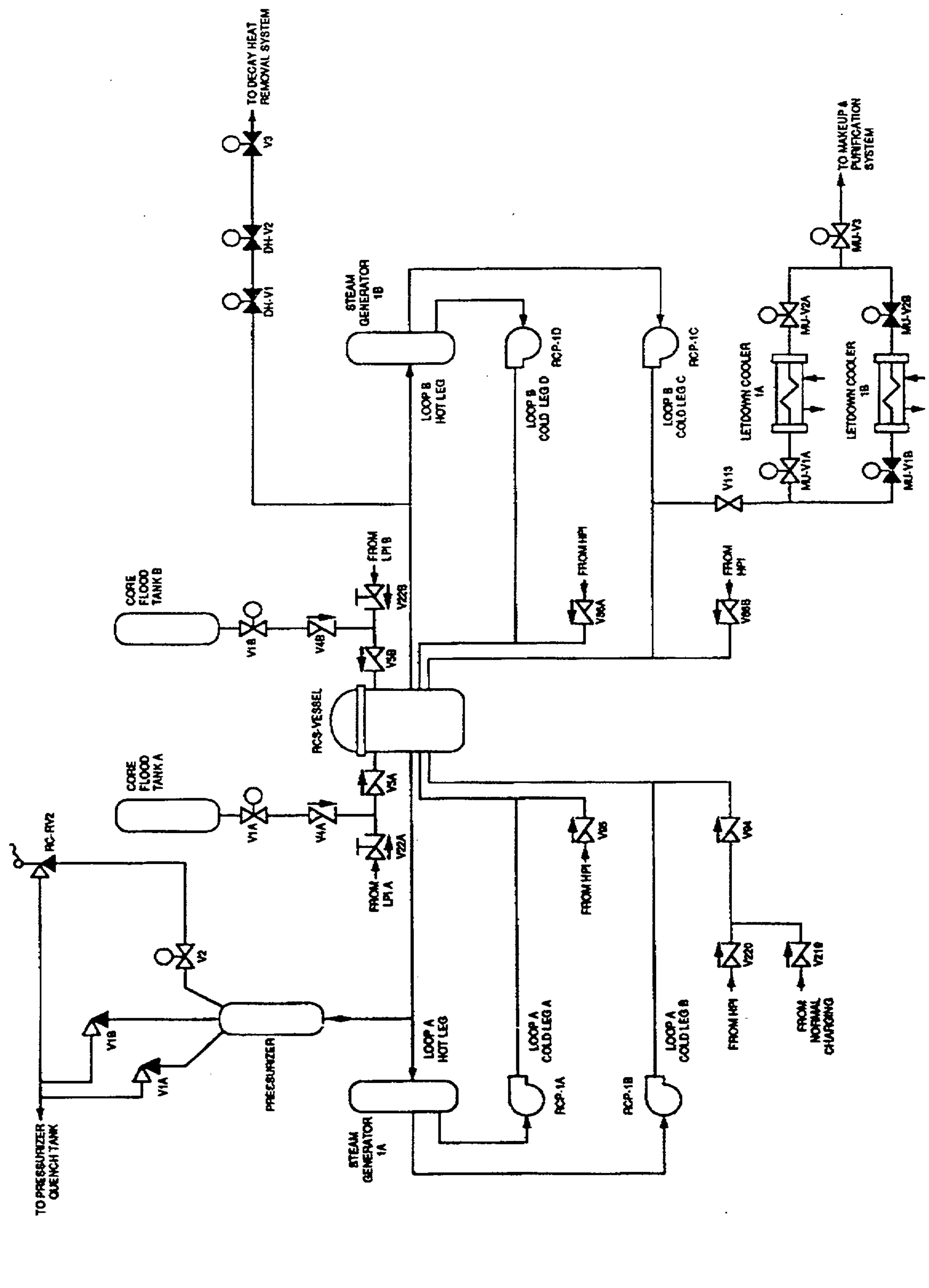

Figure 3.1 Three Mile Island 1 Reactor Coolant System Showing Location of Components

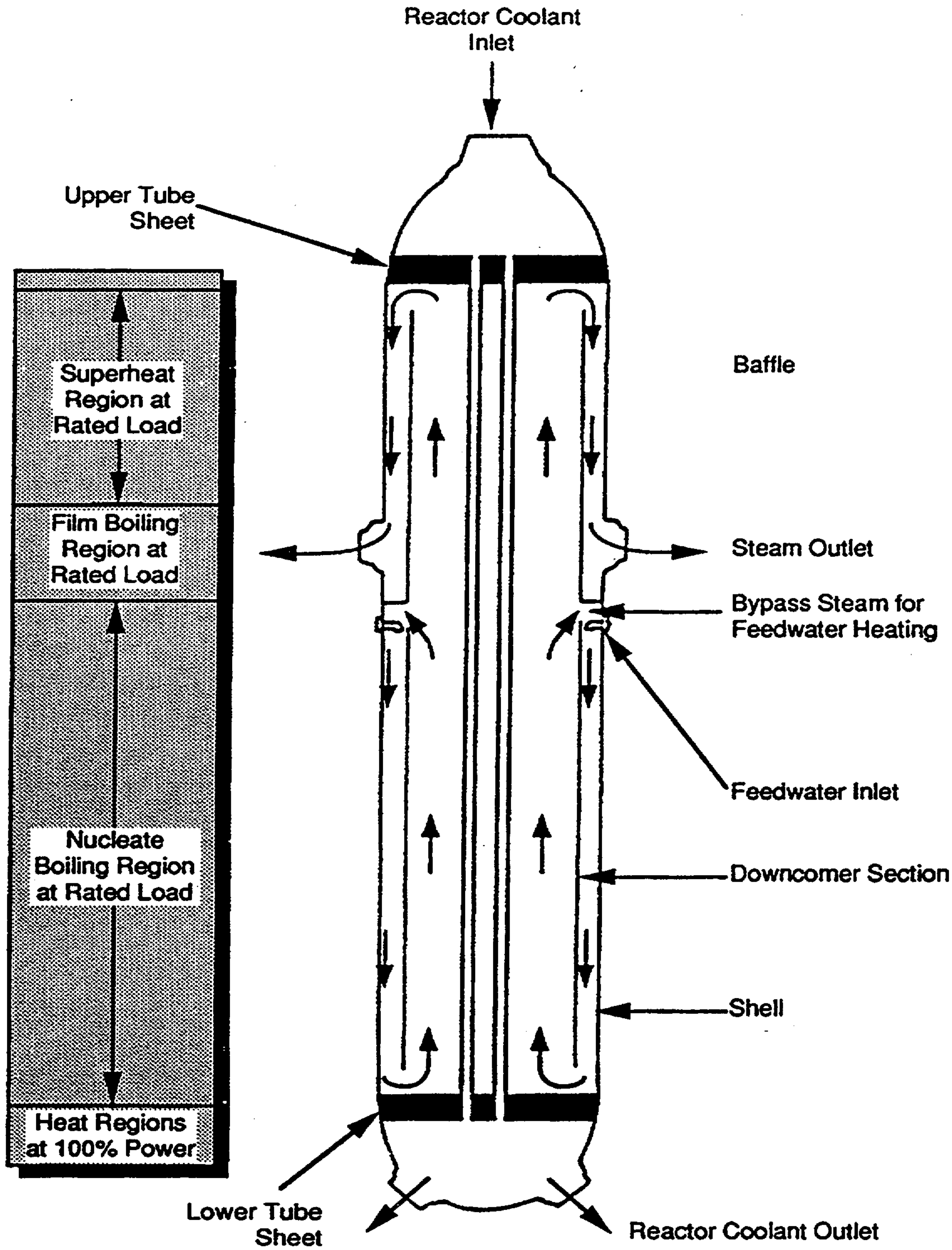

Figure 3.2 B&W 177 Plant Once-through Steam Generator

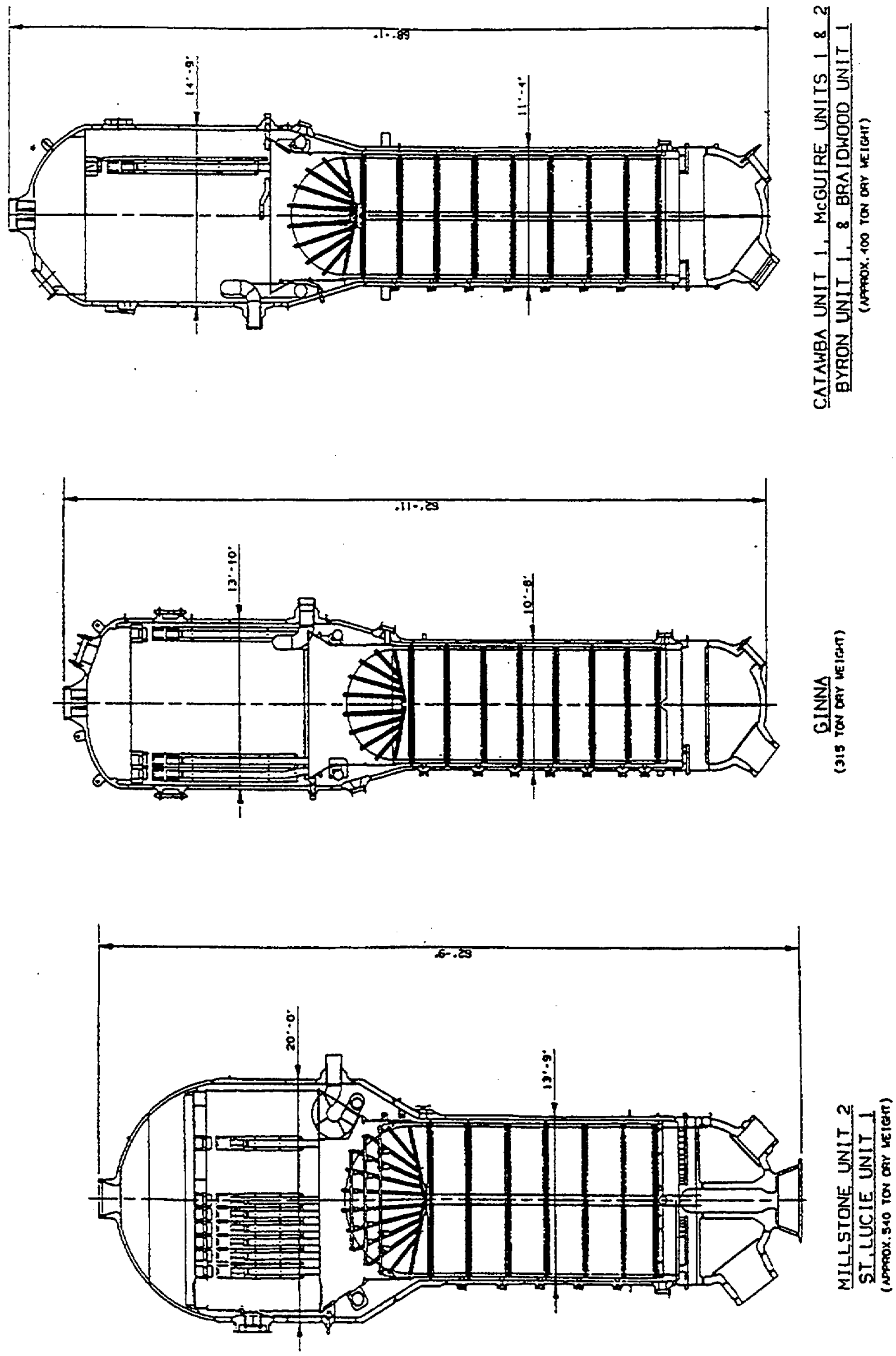

Figure 3.3 Arrangements of B&W Replacement Steam Generator

4 EVALUATION OF RESPONSES BY PLANTS WITH COMBUSTION ENGINEERING STEAM GENERATORS

Out of the 15 plants with CE-designed Nuclear Steam Supply Systems, 11 plants still have CE-designed steam generators; they are listed Table 4.1. ANO-2 replaced both of its SGs with Westinghouse D109 in December 2000. However, at the time of this review the GL responses by ANO-2 correspond to its original CE-designed SGs. Of the other three plants, Maine Yankee is permanently shutdown, and both Millstone 2 and St. Lucie 1 replaced their original steam generators with new steam generators manufactured by B&W International of Canada. Of the 11 still using CE SGs, Palisades replaced its original SGs with newer models of CE-designed units in March 1991.

Based on the differences in the tube support design of the 12 CE-designed plants (including ANO-2), the CE-manufactured steam generators fall into three categories: Type 1 - SGs with both carbon steel eggcrates and drilled plates; Type 2 - SGs with carbon steel eggcrates only; and Type 3 - SGs with stainless steel eggcrates only (Table 4.1).

As Table 4.1 shows, steam generators currently operating at CE nuclear power plants are from three specific vintages. All early vintage (Type 1) CE-designed SGs have been in commercial operation since the period from 1974 to 1980; the next group (Type 2 or Models 67, 70) began operation between 1983 to 1985; and finally, the most recent group of SGs (Model 80) were installed between 1986 to 1990. Palisades is the only older plant which has replaced its SGs with the newer System 80 model units. Thus, Calvert Cliffs 1&2, and Fort Calhoun have the oldest steam generators with carbon steel eggcrate supports and drilled hole plates at upper elevations. ANO-2 also had two of these CE-designed SGs until December 2000, when these older CE units were replaced with Westinghouse D109 model SGs. St. Lucie, San Onofre 2&3, and Waterford 3 have SGs with all carbon steel eggcrate tube supports, and Palisades, and Palo Verde 1, 2, and 3 have all stainless steel eggcrate tube supports.

Table 4.1 Plants with CE-Designed Steam Generators

Plant Name	Commercial Start Date	Tube Support Plate Design (see notes below)			Comments
		Type 1	Type 2	Type 3	
ANO 2	3/80	X			Replaced with Westinghouse model D109 in December 2000. However, the GL 97-06 responses correspond to its original CE-designed SGs.
Calvert Cliffs 1	5/75	X			Plan to install replacement SGs with stainless steel eggcrate supports in Spring 2002
Calvert Cliffs 2	4/77	X			Plan to install replacement SGs with stainless steel eggcrate supports in Spring 2003
Fort Calhoun	6/74	X			

Plant Name	Commercial Start Date	Tube Support Plate Design (see notes below)			Comments
		Type 1	Type 2	Type 3	
St. Lucie 2	8/83		X		
San Onofre 2	8/83		X		
San Onofre 3	4/84		X		
Waterford 3	9/85		X		
Palisades	12/71			X	Replaced its original SGs in Fall 1990
Palo Verde 1	1/86			X	
Palo Verde 2	9/86			X	
Palo Verde 3	1/88			X	

NOTES: TSP Type 1: Carbon steel eggcrates and drilled plates at upper elevations
TSP Type 2: Carbon steel eggcrates only
TSP Type 3: Stainless steel eggcrates only

The following sections discuss the evaluations of the licensee's submittals to GL 97-06 for plants with CE-manufactured SGs still in service.

4.1 Plants with CE-Designed Steam Generators

The CE steam generators have a vertical U-tube design, with integral moisture separators and steam dryers. All current CE plants contain two primary loops, each with one steam generator and two reactor coolant pumps (Figure 4.1). The most recent CE plant design is Palo Verde, and is called CE System 80. In the pre-System 80 plants, the feedwater inlet nozzle enters the SG above the level of the tube bundle (Figure 4.2). These SGs do not have an economizer. The System 80 SG unit is larger than the pre-System 80 designs, with feedwater entering both the downcomer and the economizer of the SG (Figure 4.3).

The CE steam generators are designed and fabricated as ASME Code Section III Class 1 vessels. The secondary structure supports 8,500 to 11,000 tubes in each SG unit, and consists of tubesheet, shroud, seven full horizontal eggcrates, three partial eggcrates, two "batwings" (anti-vibration bars) and seven vertical eggcrate supports. The eggcrate tube supports of early models were made out of carbon steel. Some older models have a combination of carbon steel eggcrates with solid drilled support plates. The newer System 80 models have eggcrate supports of 409 ferritic stainless steel. The bend and horizontal regions of the tubes in all models are supported by the batwing supports and vertical lattice supports, respectively. To minimize sludge accumulation on the tubesheet, the newer models include flow-distribution plates designed from 405 ferritic stainless steel plates with holes sized to provide a sweeping action across the tubesheet. They reduce the particle dropout that causes sludge to form.

SG Internals Degradation Experience and Evaluation

During the late 1960s and early 1970s steam generators manufactured by CE had drilled hole carbon steel tube support plates (TSPs) in the tube bundle at upper elevations. The TSPs became corroded in these early models, and this was attributed to water chemistry and ingress of balance-of-plant (BOP) contaminants, such as copper. Corrosion of the carbon steel TSPs resulted in tube denting, TSP swelling, damaged supports, and damaged tubes. Analyses showed that removing the outer portion of the drilled TSP, and cutting the plate loose from the shroud would minimize the possibility of denting and damaging the tubes, by relieving the stresses in the TSPs. Therefore, the outer rims of the TSPs were removed, and the plates were detached from the shroud at all the plants with drilled TSPs, except Calvert Cliffs 2 (since denting was not significant there). Eliminating the stress concentrations in the TSPs delayed the onset of ligament cracking in the TSP. The only way to eliminate ligament cracking in these plants is to prevent denting of the tubes by removing the cause of support plate corrosion. Other mitigating actions taken at the time included reducing the ingress of contaminants, reducing in-leakage of air, replacing copper-containing components, and treating with boric acid. These actions, together with staking or plugging some damaged tubes, essentially halted denting.

Flow-accelerated corrosion (FAC) was identified as an operational damage mechanism for the eggcrate tube supports and was observed at the San Onofre Nuclear Generating Station (SONGS) Unit 3. FAC was attributed to changes in secondary side fluid parameters caused by the buildup of deposits on the SG tubes (i.e., fouling of tube bundles). This buildup increased fluid velocities and lowered pH to levels where rapid FAC (erosion-corrosion) occurred. The fouling of the tube supports appeared related to iron transport into the unit through the feedwater (FW) system. At SONGS 3, major FAC effects were found in the peripheral regions of tube support strips of the uppermost eggcrate supports during the 1997 refueling outage (RFO). The thin tube support strips (.09" thick) expose a large surface area to the fluid flow and are vulnerable to corrosion.

The CE-designed SG has a shroud (or baffle) which separates the incoming feedwater and recirculating flow from the heat transfer tubing area. The shroud is thicker than EdF SGs and also serves as the main load path for the eggcrate and tube support plates. The cylindrical shroud can handle the lateral loadings due to seismic forces on the tubes and tube supports. The shroud is welded to 16 lower shell lugs above the tubesheet and thus it expands from the bottom similar to the tubes. The shroud has additional lateral restraint supports located near the bundle's center and at the top, which are designed to allow its axial expansion.

The CEOG developed several documents with safety and susceptibility assessments pertinent to the design and operating history of this group of steam generators. These assessments conclude reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals. Based on these reports, each licensee has addressed both the EdF causal factors and the operating experience at SONGS. Based upon the submitted documents and analyses, the following three areas were further discussed with CE engineers (in a conference call) and were the subject of a staff's requests for additional information (RAIs) to CE. Based on the CE's responses (Ref. 20), the following discussions address the concerns raised:

4 COMBUSTION ENGINEERING STEAM GENERATORS

(1) The CEOG stated that bounding safety analyses performed for Calvert Cliffs 2 and SONGS 3 show that potential degradation of peripheral eggcrate supports will not adversely affect safety. The SONGS 3 LOCA+SSE analysis and the Calvert Cliffs 2 flow induced vibration (FIV) analysis bound the remainder of the CE fleet based on the tube support design (e.g., all eggcrate type supports versus support plate/eggcrate combinations) and assumptions on degradation.

For the LOCA+SSE event, the majority of the load is applied to the top two supports. The SONGS 3 steam generators are 3410 MWt design, whose LOCA loads are limiting for all CE plants. Details of the design of the tube support structure are analogous to all SG designs and the seismic condition at SONGS bound all other CE plants. SGs with drilled plates for the top two support plates which are assumed to be intact, are bounded by SGs with all eggcrates. Because of these conditions, the SONGS 3 safety evaluation bounds the remaining CE fleet.

The analysis of FIV in drilled support plates is limiting for all CE SG designs because of the radial flow near a drilled plate compared to that near an eggcrate. At Calvert Cliffs, the SGs have tube bundle and drilled support plates for the top two tube supports. The fouling on the tube bundle diverts some of the flow to its periphery regions, and the drilled plates (also assumed to be fouled) provide more resistance to axial flow (i.e., they cause more cross-flow). Those with tube bundles with little or no fouling (such as in the original design) or with eggcrates the full length of the tube bundle are not as susceptible to FIV.

Iron transport values presented in the CEOG report for all CE plants were used only as a first level indicator of the amount of sludge loading and the potential for fouling, not as the sole justification for being the bounding analysis. In fact, iron transport rates can vary over a refueling cycle by a factor of 2 or 3, and can vary from plant to plant because of differences in the condition of SG internals due to chemical cleaning, sludge lancing, and blowdown pressure. Other parameters that were considered for the bounding issue include secondary side pressure losses and the results of secondary side inspections. CEOG member units with less fouling expected than the bounding cases (based on iron transport and pressure loss) have completed inspections, and no degradation of the support plates was discovered.

(2) Analyses of flow-induced vibrations (FIVs) for CE-designed SGs were based on the Calvert Cliffs 2 SG model, as follows: Calvert Cliffs 2 has heavier support plates at the upper elevations. A vibration stability ratio of 1.2 was determined for the critical locations with one ineffective eggcrate support. A stability ratio above 1.0 denotes unstable tube vibrations. The CEOG stated that these above 1.0 values are based on very conservative assumptions in certain input parameters. Moreover, since the long spans vibrate at stresses below the fatigue endurance limit, fatigue is not a concern. Tube wear at the supports or at the mid-span is considered to be a non-safety issue because of the length of time to develop the defect, and its leak-before-break characteristics. Potential tube failures due to unacceptable tube vibrations do not represent a risk to the safe operation or shutdown of the plant. CEOG stated that these results do not indicate that Calvert Cliffs currently has a vibration problem in the tube bundle.

Some conservatisms in the FIV analysis can be found in the "ATHOS" assumptions (e.g., all cross flow is in the worst case direction, and no credit taken for axial flow). No credit was taken for "whole bundle" behavior, when, in fact, a single tube acting unstably is not enough to cause degradation; rather two or more tubes together need to be unstable to cause tube wear. Also, no wear was detected either at SONGS 3 or at Calvert Cliffs 2 during recent eddy current inspections.

(3) FAC of the peripheral regions of eggcrates is the only significant degradation mechanism applicable to the CE-designed SGs with carbon steel TSPs that could have safety significance. This is primarily the result of redistribution of secondary fluid flow caused by severe fouling of the tube bundles, exacerbated by using ammonia to control pH.

The CEOG determined (Ref. 16) that FAC can occur over a relatively short time once a threshold in level of TSP fouling is reached. Therefore, at plants with carbon steel eggcrates and severe tube bundle fouling in peripheral eggcrate locations, the licensee should inspect these locations during each refueling outage, specifically the uppermost full eggcrate and all tube supports above it in the hot leg side. The licensees of plants without a severe fouling problem should inspect these locations once, and plan a future program for monitoring the fouling of the tube bundles at subsequent outages. The licensees of plants with a low susceptibility for FAC can credit inspections made at other units, provided the SG's geometry and operating conditions are similar.

CE cited other factors besides fouling that may cause a loss in secondary side steam pressure from the design pressure of 900 psia. These other factors are a decrease in temperature (hot side), and/or an increase in the number of plugged tubes. Since the threshold in level of TSP fouling depends on many other factors, a prescriptive inspection criterion for all plants is not possible. Plant-specific engineering evaluations may be needed to develop an inspection guideline. However, CEOG indicates that, once all factors have been corrected, a pressure reduction of more than 5% from the design condition is significant.

4.1.1 Susceptibility of the CE SGs Relative to EdF and SONGS Experience

All 12 CE plants joined the effort by the CE Owners Group (CEOG) to assess the susceptibility of tube damage or loss of decay heat removal (DHR) capability due to deterioration of secondary-side components. EPRI's report, GC-109558, "*Steam Generator Internals Degradation: Modes of Degradation Detected in EDF Units,*"(Ref. 6) was used to evaluate the causal factors involved in the modes of degradation experienced in the EdF units, and to gain insights into its applicability to their steam generator designs and operating history. In developing the susceptibility assessment, they considered other attributes: design factors, fabrication and manufacturing techniques, and operating history including chemistry and related degradation, such as denting. In addition, the CEOG compiled and assessed information on eddy current examinations, visual & video inspections, and pertinent nondestructive examinations (NDE) performed as part of the in-service inspection program.

4 COMBUSTION ENGINEERING STEAM GENERATORS

The CEOG undertook an operability assessment for all CE-designed and fabricated steam generators based on the EdF experiences and those at Maine Yankee and SONGS 3. The assessment also incorporated data on the SG internals inspections of CE-designed steam generators. CE submitted five reports (Refs. 14-18) for this review addressing the issues experienced at EdF plants and at SONGS.

The operability of the steam generators relates to their capability to maintain safety functions: (a) the structural integrity of the SG tube pressure boundary, and (b) the SG heat-removal function.

The following assessments of the degradation mechanisms identified in the GL are based on information from the CEOG reports.

(1) Erosion of the top TSP due to improper placement of hoses during chemical cleaning:

The lower flow velocities of the chemical cleaning processes used (i.e., fill and soak versus forced circulation) and less harmful cleaning agents minimize the potential for erosion from chemical cleaning in CE SGs. Full bundle chemical cleaning has been done with no reported damage in SGs at SONGS and Palo Verde.

(2) Ligament cracking of carbon steel with drilled hole TSPs due to mechanical loads during manufacturing, shipping, or early operations:

The CEOG states that this degradation mechanism, described in GL 97-06, is generally not applicable to CE SGs at the present time. The relevant design features are as follows: the steam generator is designed to accommodate differences in normal operating temperature without imposing excessive loads. The fabrication process did not include heat treatment of the complete assembly (with the tube supports attached to the shroud). Two closing girth welds (primary head to tubesheet extensions and steam drum head to upper shell) are heat treated in a local furnace.

During the early years of CE SG operation, ligament cracking of carbon steel TSPs (in Type 1 CE SGs) had resulted from denting, TSP swelling, and damage to both supports and tubes, caused by corrosion. Ligament cracks were observed at ANO-2 and Millstone 2. This degradation was brought under control by several actions, including cutting the TSP rim, reducing the ingress of contaminants and changing the water chemistry and additives. Plants with ligament cracks have noted no growth in the cracks since taking corrective actions.

(3) FAC-induced thinning of the top TSP periphery due to ammonia water chemistry:

This degradation mechanism described in GL 97-06 is generally applicable to CE SGs. With severe tube bundle fouling, CE-designed SGs with carbon steel tube supports may experience loss of secondary side pressure. Using ammonia to control pH in heavily fouled SGs increases the susceptibility to FAC. This is discussed further in item 7, below.

(4) *Wrapper-drop due to fatigue failure of supports:*

The primary mechanism of damage related to failures of the wrapper support in the EdF units is not directly applicable to the CE-designed SGs because of the robust design of the shroud and provisions to accommodate thermal expansions.

(5) *Fatigue cracks from support blocks due to flow-induced vibration of wrapper:*

This degradation mechanism described in GL 97-06 is generally not applicable to CE SGs. The shroud in CE-designed SG is adequately supported and thicker than those at EdF plants. Therefore, there should not be any excessive flow-induced vibration of the wrapper. No evidence of shroud support cracking was identified in the records.

(6) *TSP wedge block cracking:*

The CEOG stated that this degradation mechanism described in GL 97-06 is generally not applicable to CE SGs. They did not specifically address this issue, however, wedge block cracking in CE units was not identified in the experience data.

(7) *Eggcrate support degradation at SONGS due to FAC associated with fouling:*

The two most influential factors causing FAC in CE SGs are fouling and secondary chemistry. Severe fouling significantly changes the internal SG flow distribution. SONGS 3 had approximately 20% more fouling deposits by weight that SONGS 2. Further, Unit 3 experienced significant degradation of eggcrates, while Unit 2 did not. Analyses concluded that fluid dynamics and detailed local hydraulic conditions were the dominant contributors to the FAC at SONGS 3.

In addition to increasing fluid velocity in the eggcrate periphery, severe fouling reduces the overall circulation ratio in the SG. The lower recirculating flow rates increase steam quality, which causes ammonia (used at SONGS 3 to control pH) to leave the liquid phase thereby lowering the local pH. The increased steam quality may also increase fluid velocity further, raising susceptibility to FAC (p. 18 of CE-NPSD-1103, Ref. 16).

The higher iron transport rates in the secondary water at Calvert Cliffs 2 implies potentially greater tube bundle fouling and eggcrate degradation than was seen at SONGS 3. However, the additional evaluation shows acceptable results for the potential degradation of Calvert Cliffs 2.

During the recent RFO at Calvert Cliffs 2, the licensee visually inspected the secondary side of the eggcrate tube supports in the periphery of the #21 and #22 steam generators on both the hot and cold leg sides (Ref. 19). In the #21 SG, minor degradation of the eggcrate tube supports was apparent on the hot leg side at the 6th, 7th, and 8th support elevations. In the #22 SG, more extensive degradation of the eggcrate supports on the hot leg side at the 7th and 8th support elevations was found as well as on the cold side at the 6th support elevation. However, all the tubes in both SGs were adequately supported. The licensee preventively plugged 4 tubes in the #21 SG and 98 tubes in the #22 SG to prevent any continued degradation over the next operating cycle. Based on the location and nature of the degradation, the licensee concluded its cause is erosion-corrosion, similar to, but much less extensive than, that seen at SONGS 3. The licensee performed an upper bundle flush and sludge lancing of the SGs, and at the time of this review planned to adjust chemistry levels to improve resistance to erosion-corrosion. The licensee performed similar inspections of the secondary side at Calvert Cliffs 1 in 1996 and 1998, and found no degradation of the eggcrates.

Based on the bounding analyses (SONGS 3 for LOCA conditions and Calvert Cliffs 2 for flow-induced vibration), tube stresses for LOCA+SSE conditions would have a significant margin assuming two ineffective eggcrate supports. The CEOG evaluations indicate that as long as the fouling of tube bundles is minimal, degradation of the type experienced at SONGS can be managed within the safety limits for CE-designed SGs.

The CEOG addressed the issues identified in the GL for three specific degradation mechanisms: misapplication of chemical cleaning, differential thermal expansion between the components of support structures, and corrosion or erosion/corrosion. The CEOG made the following determinations:

(1) Chemical cleaning of CE-designed SGs is not likely to produce damage because less harmful cleaning agents approved by EPRI are used. The pH was maintained between 6-8 versus a low value of 3.3 used at the EdF plants. Further, the processes used in cleaning did not allow excessive impingement of the agents on the SG supports.

(2) Since the fabrication of CE-designed SGs did not include heat treatment of the complete assembly, thermal expansion is not considered to be a damage mode. The SG can accommodate normal differences in operating temperature without imposing excessive loads. Additionally, the conservatively designed supports for the tube bundle shroud (or wrapper) are not susceptible to the damage to them experienced by EdF.

(3) Corrosion and corrosion/erosion are the only mechanisms that directly apply to the CE-designed steam generators.

In summary, the CEOG evaluations indicate that as long as the fouling of tube bundles is minimized, degradation of the type experienced at SONGS can be managed within the safety limits for CE-designed SGs. These assessments provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

4.1.2 Responses to NRC's Generic Letter 97-06

During the early years of CE plant operation, the most common form of degradation of SG internals was from water hammer events, erosion of components within the FW system, and TSP distortions from denting in the tubes which led to ligament cracking. These FW system's degradation mechanisms were addressed and CEOG no longer considers them to be safety problems. Removing the rim of the distorted TSPs to relieve stresses on the plates, and injecting boron into the secondary water essentially halted any further progression of ligament cracking. All plants with early model SGs had denting at their carbon steel tube supports with drilled holes and eggcrates at upper elevations. Ligament cracking on TSPs, however, was only found at ANO 2 (since replaced), Fort Calhoun, and Maine Yankee (no longer in service). Fort Calhoun monitors TSP cracking to ensure that the cracks are not lengthening. Except for Calvert Cliffs 2, all SGs of this vintage have undergone upper TSP rim cutting. All plants with the next vintage SGs, using carbon steel eggcrates only, experienced denting of the eggcrates during their early years. Improvements in the secondary water chemistry have mitigated this particular damage.

All licensees with CE-designed SGs agreed with the following conclusions that the CEOG reached about the degradation identified in the GL. All mechanisms recently found in EdF units are generally not applicable to CE-designed steam generators. The only one applicable to the CE units that could affect safety is FAC of the peripheral regions of eggcrates at uppermost elevations, as found at SONGS 3. Further, none of these mechanisms pose a threat to the integrity of the RCS pressure boundary or the heat removal function of the steam generator. The FAC of the peripheral region is primarily the result of redistribution of secondary fluid flow caused by severe fouling of the tube bundles in the carbon steel TSPs, exacerbated by using ammonia to control secondary fluid pH. Based on operating experience, these steam generators have not encountered significant internal degradation and, of the degradation that has occurred, appropriate mitigating action has been taken to minimize its effects. Plants with stainless steel eggcrates are judged not susceptible to FAC degradation.

After a comprehensive inspection at SONGS 3, it was confirmed that FAC was primarily limited to the upper eggcrates and was confined to the periphery. The degradation was characterized by thinning of the lattice bars, with a scalloped surface indicative of FAC. Since significant fouling of the tubes that increases fluid velocities, causing FAC degradation and the buildup of deposits on them is directly related to iron transport into the SG unit through the FW system, Calvert Cliffs 2 SGs (with the highest iron transport rates) were analyzed for FAC. The LOCA evaluation indicated a significant margin in the allowable tube stresses, even with two ineffective eggcrate supports, bounded by the SONGS model. However, the Calvert Cliffs model for flow-induced vibration indicated unstable vibrations of the tube bundle even with only one ineffective eggcrate support. Nevertheless, the CEOG concluded that fatigue degradation in tubes is not a concern since the flow-induced vibration stresses are within the fatigue endurance limit for the material. CEOG considers tube wear at the supports or at the tube's mid-span is a non-safety issue because of the long duration for developing defects and the leak-before-break characteristics. The staff disagrees with the CEOG conclusion that wear is a non-safety issue because of leak-before-break characteristics. However, routine ECT would be expected to identify tube wear at supports or other locations and prevent this mode of degradation from becoming a safety issue.

The licensee stated that the primary damage mechanisms causing the wrapper supports to fail in the EdF units are not directly applicable to the CE-designed SGs, because of the robust design of the shroud and provisions to accommodate thermal expansions.

For FAC damage observed in the SONGS 3 eggcrates, CEOG's analyses indicate adequate margin against failures. The CEOG concludes that plants with appreciable degradation of eggcrate TSPs can continue to operate safely, and any damage to tubes can be detected in the normal ECT examinations.

All plant submittals addressed the intent of GL 97-06. Plant-specific data on past inspection experiences were submitted in one table as part of the CEOG evaluation. Details on the specific type of inspections (e.g., using ECT or visual/video camera), internal components inspected, the results, and the disposition of findings were generally not provided.

Because there is no qualified eddy current technique to detect degradation of eggcrate design tube supports, many licensees gave no information about its use in their inspections. Nevertheless, it is known that essentially all plants use ECT to examine SG tubes (which were not the subject of this GL). Some plants with carbon steel drilled hole TSPs in their SGs have found ligament cracking, although it is not clear if this was detected visually or by ETC. Some plants indicated using ECT for determining the presence of tube supports or any loose parts inside the steam generator.

Almost all plants have performed some kind of visual and/or video camera inspections of the SG internals during their normal RFO tasks. Details on the actual techniques used and the specific findings of the inspections generally are not given in their GL submittals. All licensees provided some results of the last inspection of the SG internals, and had not found notable degradation of internal components. Calvert Cliffs 1 was planning to review all its ECT data during the next RFO inspection. Table 4.2 summarizes the information on inspections from all plants in this group based on their submittals.

Out of the four plants with the earliest vintage of SGs, the licensee replaced both ANO 2 SGs in December 2000, and the licensee of Fort Calhoun planned at the time of this review to perform a more comprehensive SG inspection during their next RFOs. For Calvert Cliffs 1, the licensee inspected SG internals in 1996 and 1998, and found no significant damage to the eggcrates. For Calvert Cliffs 2, the licensee comprehensively inspected its two SGs in early 1999 and plugged 4 tubes in SG #21 and 98 tubes in SG #22 to mitigate the potential for continued degradation over the next operating cycle. Replacement SGs, with stainless steel eggcrate supports, will be installed in the Spring 2002 for Calvert Cliffs 1 and Spring 2003 for Calvert Cliffs 2.

Table 4.2 Plant-specific SG Inspections For CE SGs

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
ANO 2	Performed each RFO for loose parts	Fouling and denting in eggcrates	Visual and video inspections	FW (see note 1) component degradation, ligament cracks, and loose parts	Replaced SGs in December 2000. Last inspection during 5/97 included TSPs and other structural components
Calvert Cliffs 1	Performed to detect denting	TSP crevices-fouling and denting	Visual and video inspections	FW component degradation	Last inspection made during 96 and plans for a detailed one during 98 RFO.
Calvert Cliffs 2	Performed to detect denting	TSP crevices-fouling and denting	Visual and video inspections	FW component degradation	Last inspection made during 97 and plans for a detailed one during 99 RFO.

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Ft. Calhoun	Performed each RFO for TSP conditions	TSP crevice fouling and denting	Visual inspections each RFO	FW component degradation, and one TSP crack per SG	Plans to perform a more comprehensive inspection during next RFO
St. Lucie 2	Performed each RFO for TSP conditions	No degradation noted	Visual and video inspections	FW component degradation, some minor fouling, and loose parts	Has been inspecting SG internals each RFO since 1986
San Onofre 2	Performed during last inspection 2/98	No reported results	Visual and video inspections	Minor lattice thinning and pitting	More comprehensive inspection performed during 2/98. Secondary side components are in good condition
San Onofre 3	Not stated	-----	Visual and video inspections	Upper eggcrates periphery degraded	More comprehensive inspection performed during 3/98. No results are available
Waterford 3	Performed for loose parts	Loose nuts	Visual and video inspections	No degradation Some minor sludge deposits and loose parts.	Has a formal inspection program for SG internals
Palisades	Performed for TSP conditions	No degradation noted	Visual and video inspections	No degradation noted	Has a formal inspection program for SG internals
Palo Verde 1	Performed each RFO for TSP conditions	No degradation noted	Visual and video inspections	No degradation noted	Has an informal inspection program for SG internals
Palo Verde 2	Performed each RFO for TSP conditions	No degradation noted	Visual and video inspections	No degradation noted	Has an informal inspection program for SG internals
Palo Verde 3	Performed each RFO for TSP conditions	No degradation noted	Visual and video inspections	No degradation noted	Has an informal inspection program for SG internals

Note 1: FW in this table refers to feedwater system components located within the SG, such as J-nozzles, the feedring, distribution box, and thermal liner.

The San Onofre 2 & 3 SGs have undergone comprehensive NRC reviews during the year after degraded eggcrate supports were found at SONGS 3. The licensee's submittal for these two plants in response to the GL cites many other submittals to the NRC. The NRC technical monitor for this project stated that the NRC has already reviewed them and concluded that the licensee had taken appropriate corrective actions. Therefore, this evaluation drew no conclusions on the adequacy of the inspection programs at San Onofre.

Palisades and Waterford 3 have formal programs to inspect their SG internals. All other plants (except SONGS 2 & 3) have informal inspection programs. For St. Lucie 2, the licensee has been inspecting the separator and feedring equipment of both SGs since 1984. No significant degradation of SG internals components were identified at these plants during their recent inspections.

In addition to the plant specific GL submittals, the CEOG provided partially complete Tables (Tables 2-1, 2-2, & 2-3 of Ref. 16), that summarize the inspection results for the FW system, tube-bundle assembly, and steam drum region. There is additional discussion of the degradation of SG internals in CE-NPSD-1092 (Ref. 15). The new SG models installed in Palisades and Palo Verde are not included in this documentation, but the earlier models at Palisades, Millstone 2, St. Lucie 1, and Maine Yankee are included. In these earlier models, FW components found degraded in the past were either replaced with better design and materials, or repaired at the time to bring the SGs back into service; these components involved FW spargers, liners, distribution box, AFW nozzles, and pipes. Degradation of the tube bundle assembly involved fouling and denting in eggcrates causing FAC of the peripheral supports, and distortion of some early model TSPs with drilled hole tube supports. The blowdown pipe at SONGS 2 was used to remove tubesheet contaminants. Erosion just above the tubesheet caused a large through-wall hole that makes it ineffective. Finally, in some SGs the steam deflectors and the separators in the steam drum region were damaged.

Palo Verde and SONGS are the only plants which have chemically cleaned their steam generators. ANO 2 and St. Lucie 2 sludge lanced their tube supports at each RFO. The Palisades and Palo Verde plants are the only ones who indicated using FOSAR equipment during their scheduled inspections.

At all Palo Verde Nuclear Generating Station (PVNGS) units, the secondary water is treated with boric acid, and all SGs were chemically cleaned, further reducing the buildup of corrosion product at tube/support intersections. Consequently, feedwater iron transport rate were reduced to 2-5 ppb, which should avoid conditions leading to FAC. Finally, these plants will continue monitoring operational chemistry, using the results of eddy current testing, and gathering industry information to determine if future actions are required.

Overall, all CE plants have been inspecting their SG internals since their commercial start and appropriate mitigating actions were taken for identified degradation in SG internal components. Therefore, licensees have concluded that no near-term inspections of the internals are required, and they have maintained compliance with the current licensing bases.

Since CE-designed steam generators with carbon steel supports are susceptible to FAC at their peripheral TSPs due to excessive tube bundle fouling. All plants in this group should monitor the fouling levels (which can lead to a drop in secondary side pressure) associated with these SGs, and also wear in the tubes due to unstable flow-induced vibrations of the tube bundles. CEOG's evaluation does not clearly define the threshold for tube bundle fouling, beyond which eggcrate supports are vulnerable to FAC, because it depends on plant-specific attributes. Plant-specific engineering evaluations may be needed to develop an inspection guideline. However, CEOG indicates that, once all factors have been corrected, a pressure reduction of more than 5% from the design condition is significant.

4.1.3 Summary and Conclusions

The plants (Calvert Cliffs 1&2, Fort Calhoun) with early vintage (Type 1 or Models 67/70) CE-designed SGs, with carbon steel eggcrates and drilled hole TSPs at upper elevations, have been inspecting their SG internals since their commercial start. The inspections included the tube bundle area, FW system components, and steam drum region of the steam generator. The next group of plants (St. Lucie 2, SONGS 2&3, and Waterford 3) contain Type 2 SGs with carbon steel eggcrate tube supports only. Their SG internal components have been inspected, similar to the first group of plants. Both SONGS units were separately reviewed by the NRC after reporting degradation of the eggcrate's periphery during the 4/97 RFO. St. Lucie has inspected its SG internals at each RFO since 1984. The final group of plants (Palisades and Palo Verde 1,2,&3) have Type 3, the most advanced CE-designed steam generators, which contain stainless steel eggcrate tube supports only. All plants at Palo Verde have undergone chemical cleaning, while Palisades inspects its SG internals regularly.

Historically, plants with older CE-designed SGs experienced the industry-wide problems of tube denting, degradation of FW system components within the SG, and within the steam drum region of the SG. The licensees appear to have taken appropriate corrective actions to alleviate these problems when they were discovered. Although the inspections at these plants are not formalized (except at Palisades and Waterford 3), the summary results, as reported, have been good, showing no notable degradation (except at SONGS 3). NRC separately reviewed SONGS 3 in detail.

The steam generator internals degradation mechanisms described in GL 97-06 are generally not applicable to CE-designed SGs. The only degradation mechanism applicable to the CE fleet that could have safety significance is FAC of the peripheral regions of eggcrates. This occurs primarily due to the secondary flow distribution caused by severe tube bundle fouling. A secondary cause of FAC, which is exacerbated by severe fouling, is the use of ammonia for secondary fluid pH control.

One significant degradation mechanism is currently applicable to the CE-designed SGs with carbon steel TSPs that could have safety significance, namely flow-accelerated corrosion (FAC) of the peripheral regions of eggcrates. A pressure reduction of more than 5% from the design condition due to internal fouling is considered significant. Plant-specific limits on this pressure loss must be determined to properly monitor the amount of fouling in the SG tube bundles.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

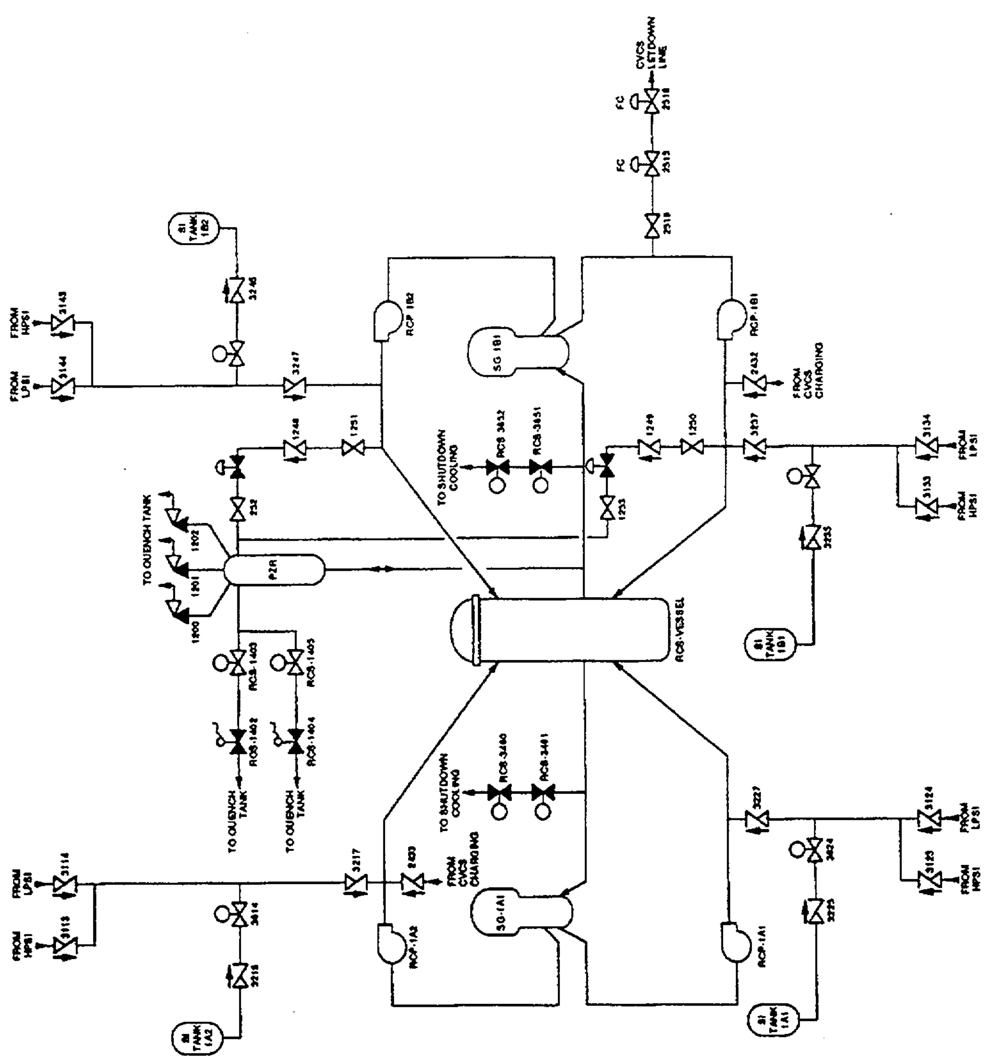

Figure 4.1 Reactor Coolant System for CE Plants

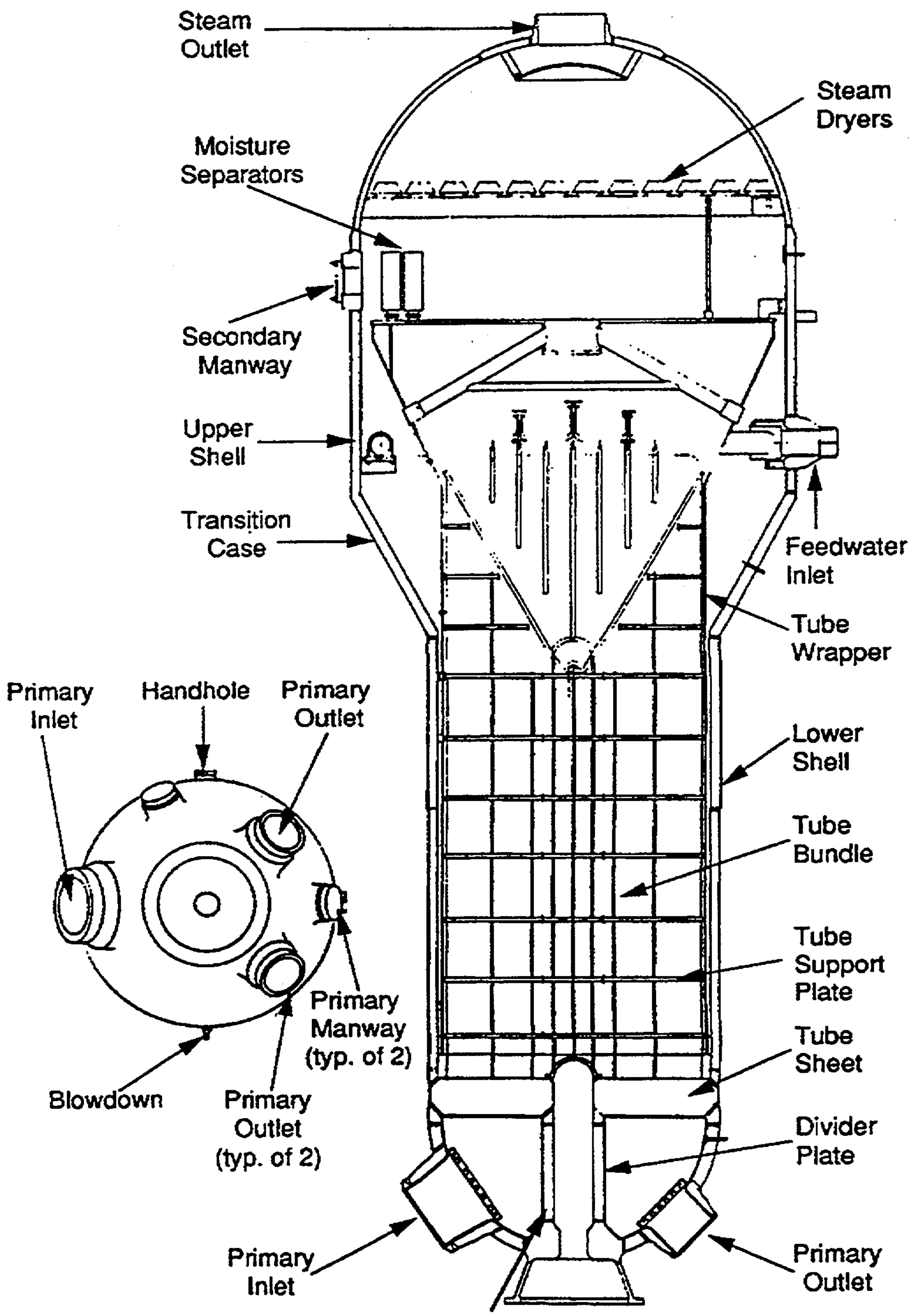

Figure 4.2 Combustion Engineering Recirculating Steam Generator (Typical for 2-Loop System 69 Plants)

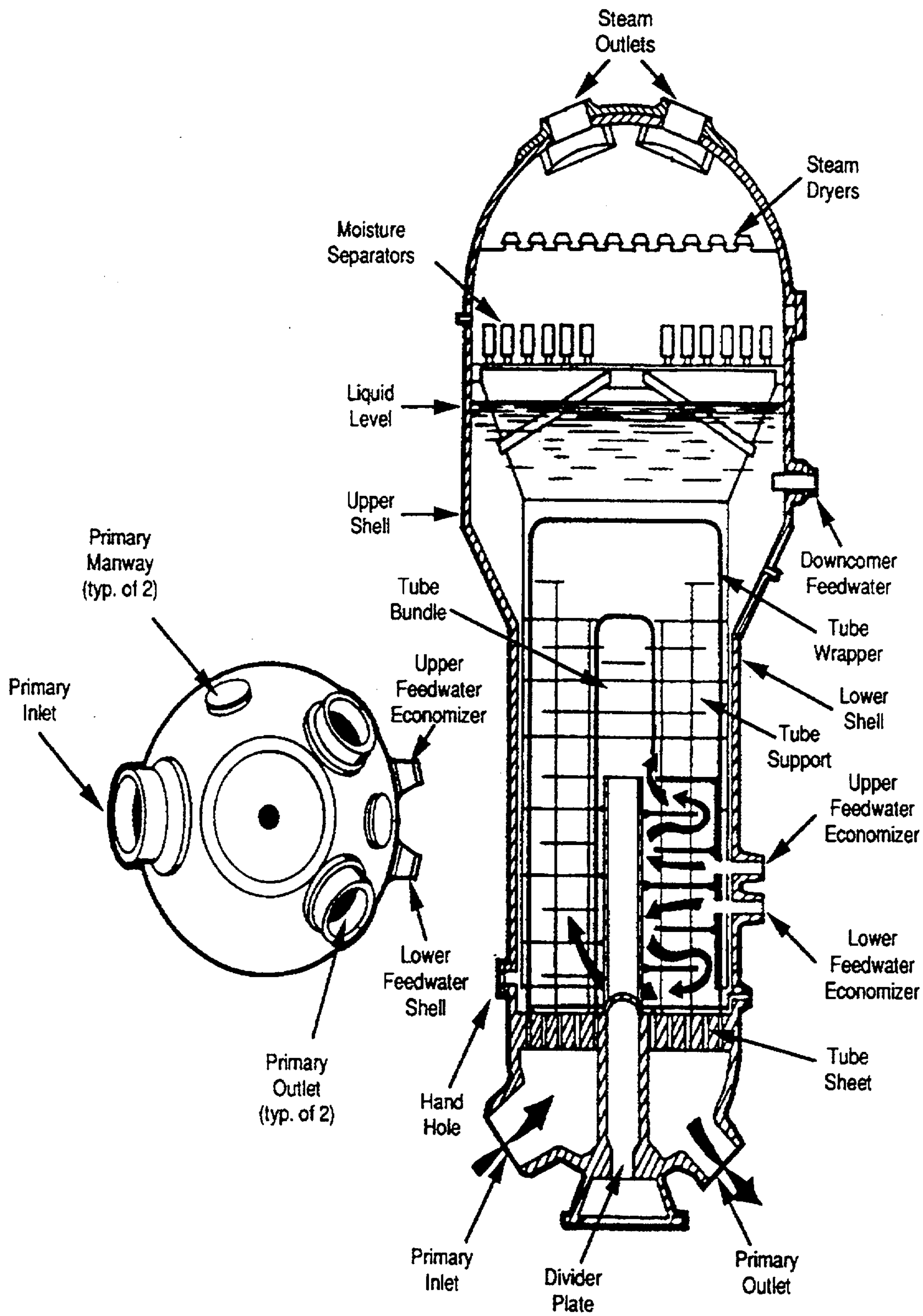

Figure 4.3 Combustion Engineering Recirculating Steam Generator (Typical for System 80 Plants)

5 EVALUATION OF RESPONSES BY PLANTS WITH WESTINGHOUSE STEAM GENERATORS

Over forty reactor units currently have Westinghouse (W) steam generators, involving about a dozen different W-designed SG models. The earlier W-designed models (e.g., Models 24, 27, 33, 44) were followed by 51-series and D-series SGs. Several licensees have replaced their original SGs with enhanced models (44F, 51F, and 54F). These enhanced models use hydraulically expanded, thermally treated Alloy 600 tubing and 405 stainless steel tube support plates (TSPs) [except for model 54F, used at Cook 2 and Indian Point 3 which has thermally treated Alloy 690 tubing]. The replacement models generally match the heat transfer area of the SGs they replace except for the model 54F units with Alloy 690 tubing, which are slightly larger than the original model 51 units, due to the lower thermal heat transfer properties of the Alloy 690 material vis-a-vis the Alloy 600 material.

Westinghouse SG models in service at nuclear power plants in the United States can be categorized by two basic designs: feed ring and preheat. Models 44, 44F, F, 51-series, 54F, Delta 47 and Delta 75 are feed ring SGs, and Models D-series and E2 are preheat SGs. The feed ring design utilizes a feed ring and J-nozzles while the preheat design uses a waterbox to supply feed water to the SGs. The most recent W-designed SG models include D5, E2-THX, F, Delta 47 (or Δ47), and Delta 75 (or Δ75) units, with stainless steel broached (quatrefoil or trefoil) TSPs in place of the older models' carbon steel drilled hole TSPs with flow holes. The delta-series models are larger and have broached trefoil TSPs made out of 405 stainless steel. Most of them, and some later 51-series models, are equipped with flow-distribution baffles. The tubes are fabricated from thermally treated alloy 690.

At the time of the GL issuance, Indian Point 2 was the only plant with four W model 44 steam generators still in service. The SGs had experienced significant denting during last 25 years of service. The EdF experiences are not related to TSP degradation and tube denting; therefore, W model 44 SGs are not included in either of the two separate W Owners Group evaluations. However, the model 44 SGs at Indian Point 2 had similar features to the 51-series steam generators. On February 15, 2000, after excessive leakage from a failure in a low row U-bend in one of the SGs, Indian Point 2 was shutdown. The licensee replaced all four of its model 44 SGs with model 44F in December 2000, prior to restart. Since the original SGs are not covered by the WOG evaluations, it is evaluated separately in Section 5.3. Section 5.3.1 discusses the evaluation of the plant-specific submittal in response to GL 97-06 relative to the old SGs. Section 5.3.2 discusses the results of the post-shutdown evaluation of the February 15, 2000 event as it relates to SG internals degradation.

WOG evaluated all its SG models in two groups. The first group includes the 51-series SGs consisting of Westinghouse models 51, 51M, 51F, and 54F discussed in WCAP-15002 (Ref. 21) and WCAP-15031 (Ref. 22). These evaluations address the EdF causal factors in the GL. The 51-series SG designs are the most similar to the EdF units described in the GL. Westinghouse also included two other replacement SG designs, the Delta 47 and Delta 75 in these evaluations because of a stated "similarity in design." The second group includes W SG models 44F, F, D3, D4, D5, and E2, discussed in WCAP-15093 (Ref. 23) and WCAP-15104 (Ref. 24). Table 5.1 lists the PWRs having Westinghouse steam generators and gives the model, number of SGs, and pertinent comments. Depending on the number of loops in reactor primary system design, each plant may have two to four SGs in service (see Figures 5.1 and 5.2 for examples of the primary system design).

5 WESTINGHOUSE STEAM GENERATORS

WCAP-15031 includes inspection guidelines for all W-design SG models as consensus recommendations of the WOG SG Internals Task Team. These guidelines provide the minimum scope inspection for an SG secondary side internals inspection program. The guidelines are specific to each W SG type, and are targeted to inspect those portions of the SG internals judged to be susceptible to degradation. WCAP-15093 and WCAP-15104 contain the final inspection guidelines both for W 51-series SGs and W models F, 44F, D-series and E2 SGs.

Table 5.1 Plants with W-Designed Steam Generators

Plants with Westinghouse SG Models (51, 51M, 51F, 54F, Δ47, Δ75)					Plants with Westinghouse SG Models (44, 44F, F, D3, D4, D5, E2)				
Plant Name	**Comm. Start Date**	**SG Model**	**# of SGs**	**Comments**	**Plant Name**	**Comm. Start Date**	**SG Model**	**# of SGs**	**Comments**
Beaver Valley 1	10/76	51	3		Byron 2	8/87	D5-3	4	
Beaver Valley 2	11/87	51M	3		Braidwood 1	7/88	D4	4	Replaced in 11/98 with BRSGs
Cook 1	8/75	51	4	Replaced in 2000 with B&W RSGs	Braidwood 2	10/88	D5-3	4	
Cook 2	7/78	54F	4	Replaced lower section in 1988-89	Callaway	12/84	F Early Model	4	
Diablo Canyon 1	5/85	51	4		Catawba 2	8/86	D5-2	4	
Diablo Canyon 2	3/86	51	4		Comanche Peak 1	8/90	D4-2	4	
Farley 1	12/77	51	3		Comanche Peak 2	/92	D5-2	4	
Farley 2	7/81	51	3		Shearon Harris	5/87	D4-2	3	
Kewaunee	6/74	51	2		Indian Point 2	8/74	44	4	Not evaluated for EdF causal factors. Replaced

Plants with Westinghouse SG Models (51, 51M, 51F, 54F, Δ47, Δ75)					Plants with Westinghouse SG Models (44, 44F, F, D3, D4, D5, E2)				
Plant Name	Comm. Start Date	SG Model	# of SGs	Comments	Plant Name	Comm. Start Date	SG Model	# of SGs	Comments
									with W 44F in 12/2000
North Anna 1	6/78	54F	3	Replaced lower section in 1993	Indian Point 3	8/76	44F Late Model	4	Replaced in 1989
North Anna 2	12/80	54F	3	Replaced lower section in 1994-95	Millstone 3	4/86	F Late Model	4	
Point Beach 2	10/72	Delta 47	2	Replaced in 1996	Point Beach 1	12/70	44F	2	Replaced lower section in 1983
Prairie Island 1	12/73	51	2		Robinson 2	3/71	44F	3	Replaced lower section in 1984
Prairie Island 2	12/74	51	2		Salem 1	6/77	F Late Model	4	
Salem 2	10/81	51	4		Seabrook 1	/90	F Late Model	4	
Sequoyah 1	7/81	51	4		South Texas 1	8/88	E2 - TGX	4	
Sequoyah 2	6/82	51	4		South Texas 2	6/89	E2 - THX	4	
Summer 1	1/84	Delta 75	3	Replaced in 1994	Turkey Point 3	12/72	44F First Model	3	Replaced lower section in 1981
Surry 1	12/72	51F	3	Replaced lower section in 1980	Turkey Point 4	9/73	44F	3	Replaced lower section in 1982

Plants with Westinghouse SG Models (51, 51M, 51F, 54F, Δ47, Δ75)				
Plant Name	**Comm. Start Date**	**SG Model**	**# of SGs**	**Comments**
Surry 2	5/73	51F	3	Replaced lower section in 1979

NOTES:
(1) Models 44, 51, & 51M have Feed Rings and Carbon Steel TSPs.
(2) Models D3, D4, & E2-TGX have Preheat and Carbon Steel TSPs.
(3) Models F, 44F, 51F, 54F, Δ-47, & Δ-75 have Feed Rings and Stainless Steel TSPs.
(4) Models D5 & E2-THX have Preheat and Stainless Steel TSPs.

Plants with Westinghouse SG Models (44, 44F, F, D3, D4, D5, E2)				
Plant Name	**Comm. Start Date**	**SG Model**	**# of SGs**	**Comments**
Vogtle 1	6/87	F Late Model	4	
Vogtle 2	5/89	F Late Model	4	
Watts Bar	6/92	D3	4	
Wolf Creek	9/85	F Early Model	4	

Shaded plants submitted GL responses corresponding to their original SG models.

The following sections discuss BNL's evaluations of the licensee responses to GL 97-06. Section 5.1 evaluates the responses for models 51, 51M, 51F, 54F, Δ47, and Δ75 and Section 5.2 for models 44F, F, D3, D4, D5, and E2. Section 5.3 evaluates the response for Indian Point 2 model 44 steam generators, which were replaced with model 44F SGs in December 2000.

5.1 Plants with W-Designed Steam Generators, Models 51, 51M, 51F, 54F, Δ47, and Δ75

This group of SGs are the most similar among the Westinghouse models to the EdF units described in the GL (see Figure 5.3). The 51 series SGs include W models 51, 51M, 51F, and 54F and, because of a stated similarity in design, WOG also included models Δ47 and Δ75 for evaluating the susceptibility to degradation types outlined in the GL. Table 5.1 lists 20 plants which are currently using one of these W-models. These models all have the feed ring design. Since this evaluation took place, Cook 1 replaced its model 51 SGs with B&W recirculating SGs in 2000. Out of the 19 plants (excluding Cook 1), 12 have W models 51 and 51M which are designed with carbon steel drilled round hole TSPs, with flow holes. The remaining 7 plants have models 51F, 54F, Δ47, and Δ75 with stainless steel and trefoil or quatrefoil broached type TSPs. One additional plant, Indian Point 2 had W model 44 SGs which have similar TSPs and feed ring components to that of the model 51 and 51M.

Table 5.2 shows the distribution of the six different steam generator models consisting of 59 individual SGs. There are 38 Model 51 or 51M SGs in 12 NPP Units; these are the original W models with carbon steel (CS) TSPs. Cook 1 replaced its four model 51 SGs in 2000. The licensee for Kewaunee replaced its original equipment (model 51 SGs) in Fall 2001. There are 21 SGs with stainless steel (SS) TSPs

(Models 51F, 54F, Δ47, or Δ75). These are replacement SGs that were installed in 7 NPP units between 1980-1995.

Table 5.2 Distribution of SG Models 51, 51M, 51F, 54F, Δ47, and Δ75

SG Design Type	Model #	# of NPP Units	# of SGs
Feed Ring Models with CS TSPs:	51	11*	35
	51M	1	3
Feed Ring Models with SS TSPs:	51F	2	6
	54F	3	10
	Δ47	1	2
	Δ75	1	3
TOTALs	6 Models	19	59

* This excludes Cook 1 that replaced its 4 model 51 SGs with B&W RSGs in December 2000.

SG Internals Degradation Experience and Evaluation

The WOG sent out surveys to all WOG licensees requesting the results of all secondary side inspections and relevant tube inspections for TSP conditions. Most, but not all, licensees responded. These data were summarized in WCAP-15031. Based on the responses to this survey, erosion-corrosion of moisture separators and the feed ring/J-tubes and cracking of transition cone girth welds were observed in some SGs. Cracking of TSP ligaments associated with models 51 and 51M (with carbon steel TSPs) was also observed in some SGs. The TSP flow holes and ligaments are found to be susceptible to erosion-corrosion damage for models 51 and 51M SGs, while the TSP ligaments in models with stainless steel TSPs (51F, 54F, Δ47, or Δ75) do not experience corrosion in the tube-to-tube support plate intersections and, hence, have low susceptibility to cracking. Because of the design, the wrappers in all SGs in this group have low susceptibility to cracking near the wrapper supports and, hence, are unlikely to experience wrapper drop.

Overall, WOG's conclusions on the 51-series SGs include the following:

(1) SG designs secured by patch plates and plug welds are susceptible to inspection indications,

(2) The TSPs are not susceptibility to TSP ligament cracking near the wedge supports,

(3) The TSPs are not susceptibility to wrapper drop or cracking of the wrapper at the lower supports,

(4) The potential for TSP flow hole erosion-corrosion does not exist in SGs with stainless steel TSPs and is very low in units with carbon steel TSPs, and

(5) Missing pieces of carbon steel TSP ligament and ligament indications (cracks) are likely the result of out-of-tolerance drilling alignment during manufacturing.

WCAP-15031 concludes that the causal factors identified by EdF do not jeopardize the continued operability of this group of SGs. Eddy current inspections of tubes would detect any detrimental effects on the tubing due to wear caused by TSP ligament degradation, loose parts, or changes in secondary flow distribution. They further state that foreign object search and retrievals (FOSARs) are routinely performed to uncover loose parts inside the SGs.

5.1.1 Susceptibility of the W SGs Relative to EdF and SONGS Experience

All plants in this group joined the effort by the Westinghouse Owners Group (WOG) to assess the susceptibility to tube damage or loss of decay heat removal (DHR) capability due to degradation of the secondary-side components. EPRI report, GC-109558, "*Steam Generator Internals Degradation: Modes of Degradation Detected in EDF Units,*" (Ref. 6) was used to evaluate the causal factors involved in the modes of degradation experienced in the French units. The WOG used this report to assess the applicability of the French experience to their SG designs and operating history. They also considered other attributes: design factors, fabrication and manufacturing techniques, and operating history, including chemistry and related degradation, such as denting. In addition, the WOG compiled an industry-wide survey and assessed information on their eddy current examinations, visual, video and pertinent nondestructive examinations (NDE) made as part of the in-service inspection (ISI) experience.

WOG performed the evaluation of the impact on this group of W SGs of the EdF causal factors using a process that included the following: extracting the events, chemistry implications, loading conditions, materials and geometric features that constitute the EdF causal factors; reviewing the results of the inspection survey; evaluating the modes of degradation; establishing the evaluation criteria; reviewing modes of operation and design features of the SGs, establishing which criteria are satisfied or not, and identifying recommendations for continuing to establish SG operability.

The following assessments of the degradation mechanisms identified in the GL are based on the information in the WOG report (WCAP-15031).

(1) Erosion of the top TSP due to improper placement of hoses during chemical cleaning:

There has been no evidence of post-chemical cleaning inspections discovering any significant material losses in TSPs.

(2) Ligament cracking of carbon steel with drilled hole TSPs due to mechanical loads during manufacturing, shipping, or early operations:

According to WOG, the only models susceptible to this deterioration are 51 and 51M because of the unique design of their wrapper, tube support plate, and associated attachments that could generate additional tensile loads and may cause TSP ligament cracking. Also, W indicated that TSP ligament cracking or missing pieces of ligaments were observed, but only in units with CS

TSPs (both 51 and 51M models) with drilled round holes and flow holes. Sequential inspections showed that the damage generally is traceable back to the initial inspections and is not progressing. Many are related to drilling misalignment during manufacturing. There are cases of indications in TSPs that have been linked to patch plate plug welds. WOG stated that for W models 51 and 51M which have patch plates, indications of cracking near the patch plate plug welds is possible. The WOG also stated that if sections of the TSPs were missing, this would be readily detectable by eddy current testing (ECT) performed at each refueling outage (RFO). Therefore, ligament cracking identified at various plants with W models 51 and 51M SGs is postulated to be associated with either the patch plate rejoining process or possible misdrilling of flow holes. Recent inspections at all such plants found no change in ligament degradation.

The wrapper and tube support plate design in the other four W SG models, 51F, 54F, Δ47, and Δ75 ensure efficient load transferring without causing tensile overload. Therefore, these SG models are not susceptible to ligament cracking at, or near, the wedges and the plug welds.

(3) *FAC-induced thinning of the top TSP periphery due to ammonia water chemistry:*

The water chemistry at French plants, with low hydrazine concentration and with ammonia at low pH, are the primary causes for early TSP degradation. U.S. plants have been using EPRI guidelines since 1982 where the secondary water is maintained near neutral which is less harmful to carbon steel TSPs. Also, FAC has not been observed in 51 series SGs with CS TSPs in W steam generators in service at U.S. nuclear power plants.

(4) *Wrapper-drop due to fatigue failure of supports:*

Because of the design of the wrapper supports (e.g., inclined wedges and through-wall welds) that resist wrapper drop, W models are not susceptible to this failure mechanism. Moreover, no obstructions of FOSAR equipment with the wrapper were identified during routine inspections; thus, there has been no evidence of wrapper drop in any plant.

(5) *Fatigue cracks from support blocks due to flow-induced vibration of wrapper:*

The tendency for W designed wrappers to vibrate due to flow-induced vibration is stated to be much less than that in the EdF units.

(6) *TSP wedge block cracking:*

Configurations of the wedge block welding joints promote full penetration welds at the lower support. Routine ASME Section XI ISI of shell welds indicated no degradation at any plant, except in a feed ring type replacement SG with stainless steel TSPs whose original upper shell was not replaced. As stated above, because of the design of the wrapper supports (e.g., inclined wedges and through-wall welds) that resist wrapper drop, W models are not susceptible to this failure mechanism.

(7) *Eggcrate support degradation at SONGS due to FAC associated with fouling:*

No specific discussion was included in the WOG report about the TSP degradation experienced at CE designed SGs at SONGS. However, FAC associated with fouling has not been reported in any W SGs.

In summary, some of these SGs, specifically models 51 and 51M, are vulnerable to TSP flow hole/ligament erosion-corrosion, TSP ligament indications near the patch plates, and TSP ligament cracking in random areas. These types of degradation that occurred early in the operating life of the SGs, are not progressing. ECT examination at each RFO will monitor them. Therefore, these assessments provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

5.1.2 Responses to NRC's Generic Letter 97-06

Most responses by the licensees for this group of plants provided the information requested by the GL. The EdF causal factors were addressed by the WOG's evaluation discussed above. No plant discussed the SONGS experience relating to FAC at the periphery of TSPs. However, WOG evaluated this causal factor and stated that the plant data indications at the first three TSPs are not progressive and continuing. ECT examinations at each RFO will continue monitoring them. Most plants in this group perform FOSAR and sludge lancing every RFO, very few have chemically cleaned their SGs, even after over 20 years of service life. However, most have been monitoring several TSP indications using eddy current examinations at each RFO as part of the inspection for tube support cracking.

All plants employ visual and/or remote camera examinations of the upper package of the SG internals which includes the steam drum, moisture separators, feed ring with associated components (e.g., J-tubes, CS feed ring adjacent to the J-tubes, T-section, reducers, backing rings, and the thermal sleeve). The transition cone girth weld and other FW nozzle welds are regularly inspected in accordance with the ASME Section XI requirements. The degradation mechanisms associated with wrapper drop and wrapper cracking are examined only if there is any interference to the sludge lancing equipment when inserting it to clear the SG internals. No inspection is scheduled unless there is evidence of the wrapper's misposition or tube damage in the periphery of the first TSP. If detected, the lower wrapper support blocks are visually examined.

Based on the WOG's survey of these plants, there is no evidence of post-chemical cleaning inspections discovering any significant material losses, nor evidence of any wrapper drop. The TSP ligament cracking or missing pieces of ligaments were observed only in units with carbon steel TSPs which have drilled round holes and flow holes. However, these conditions generally are traceable to initial inspections or are not progressing based on sequential inspections. Many of these conditions are believed to be related to drilling misalignment during manufacturing. Many cases of indications detected by the eddy current examinations are linked to patch plate plug welds.

All plants in this group have undertaken visual/video inspections of their tube bundles and other SG internals and found no existing significant degradation in any component. Some plants have replaced their carbon steel J-tubes with replacement parts that are more resistant to erosion-corrosion damage. Although it was not clearly mentioned, all plants appear to perform FOSAR and sludge lancing operations on each SG unit during every RFO as part of their maintenance work. Some found loose objects which were either removed from the SG (if possible) or left inside in such a manner as to mitigate their potential effect on other internal components.

Eddy Current Testing (ECT) is used to examine the TSPs. Seven of the W plants have stainless steel TSPs with either trefoil and quatrefoil broached hole designs. ECT cannot detect indications of ligament cracking with these designs, but can ascertain the correct position of TSPs. The other 13 plants in the group have carbon steel TSPs with dirlled holes and have indicated they use ECT to monitor their existing indications, and that none have progressed. At the time of this study the licensees for Beaver Valley 2 and Kewaunee had not completed reviewing their past ECT data, and planed to complete ECT and reviews during the next RFO. Table 5.3 summarizes the inspection findings from all plants in this group based on the information in their submittals.

Table 5.3 Plant-specific Inspections For W SGs Model 51, 51M, 51F, 54F, Δ47, and Δ75

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Beaver Valley 1	Performed for TSP degradation	21 indications	Visual and video inspections	No significant degradation noted	FOSAR/Sludge lancing each RFO
Beaver Valley 2	Not stated	----	Visual and video inspections	No significant degradation noted	FOSAR/Sludge lancing each RFO. Plan to screen ECT data during next RFO in 9/98
Cook 1	Performed for TSP degradation	1 indication	Visual inspection	No degradation noted	Replaced all SGs with B&W RSGs in 2000. GL responses correspond to the W model 51 SGs.
Cook 2	Performed for TSP locations	No abnormal condition noted	Visual inspection	No degradation noted	No plan for next RFO inspections. However, subsequent ones will include SG internals
Diablo Canyon 1	Performed for TSP degradation	244 indications	Visual inspection	No degradation noted	Has a formal program for SG internals
Diablo Canyon 2	Performed for TSP degradation	126 indications	Visual inspection	No degradation noted	Has a formal program for SG internals
Farley 1	Performed for TSP degradation	39 indications	Visual and remote camera	No degradation noted	Has a program for SG internals

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Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Farley 2	Performed for TSP degradation	29 indications	Visual and remote camera	No degradation noted	Has a program for SG internals
Kewaunee	Performed for TSP degradation	94 indications	Visual and remote camera	No degradation noted	Has a program for SG internals. Plan to review ECT data during next RFO on 10/17/98
North Anna 1	Performed to detect missing TSP or parts	No degradation noted	Visual and video inspections	No degradation noted	Has a program for SG internals
North Anna 2	Performed to detect missing TSP or parts	No degradation noted	Visual and video inspections	Replaced two feed rings	Has a program for SG internals
Point Beach 2	Not stated	-----	Visual inspections	No degradation noted	Will develop an inspection program for SG internals
Prairie Island 1	Performed for TSP conditions	6 indications	Visual and video inspections	No degradation noted	Has a formal inspection program for SG internals
Prairie Island 2	Performed TSP conditions	No degradation noted	Visual and video inspections	Damage noted to wrapper support block ligament	Has a formal inspection program for SG internals
Salem 2	Performed for TSP conditions	12 indications	Visual and video inspections	Loose parts retrieved	Has a formal inspection program for SG internals
Sequoyah 1	Performed for TSP conditions	Indications tracked since 1990	Visual and video inspections	No degradation noted	Has a formal inspection program for SG internals
Sequoyah 2	Performed for TSP conditions	Indications tracked since 1990	Visual and video inspections	No degradation noted	Has a formal inspection program for SG internals
Summer 1	Performed for TSP locations	No degradation noted	Visual and video inspections	No degradation noted	Replaced SGs in 1994 with Delta 75 models. Plans secondary side inspection during next RFO
Surry 1	Performed for TSP locations	No degradation noted	Visual and video inspections	No degradation noted	Has a formal inspection program for SG internals
Surry 2	Performed for	No	Visual and	No degradation	Has a formal inspection program

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
	TSP locations	degradation noted	video inspections	noted	for SG internals

5.1.3 Summary and Conclusions

All plants in this group have programs to inspect for degradation of SG tubes and SG internal components. Many have adopted the WOG's recommendations for inspecting SG internals to address the relevant EdF causal factors, or are planning to adopt them as appropriate to their SGs.

Based on the licensee's submittals, the 12 plants (excluding Cook 1) with Model 51 and 51M SGs which have carbon steel drilled holes and flow holes have TSP ligament indications or missing pieces of ligaments. These ligament indications were observed near the patch plates and randomly elsewhere. None of this ligament degradation has progressed since its discovery. The other 7 plants with stainless steel broached trefoil or quatrefoil TSPs have not found any evidence of degradation. All reported no significant degradation in any of their SG internal components, except a few who earlier replaced their degraded carbon steel J-nozzles with newer nozzles made of more corrosion-erosion resistant materials.

Although all have not so confirmed, each plant appears to perform FOSAR and sludge lancing operations during each RFO. In addition, plants with carbon steel TSPs perform eddy current testing routinely each RFO to detect any new TSP degradation or to monitor the existing indications. Plants with stainless steel broached hole TSPs carry out eddy current testing for the presence of a TSP at all intersections.

In summary, all W plants have inspected their SG internals since their commercial start, and have taken mitigating actions for identified degradation in SG internal components. Licensees, therefore, concluded that no additional inspections of the internals are required at this time, and that they have maintained compliance with the licensing bases.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

5.2 Plants with W-Designed Steam Generators, Models 44F, F, D3, D4, D5, and E2

The second group of W-designed steam generators includes SG models F, 44F, D3, D4, D5, and E2. Unlike the first group (51-series W models) which contain only the feed ring type, this group contains both feed ring and preheat design SGs. Table 5.4 lists which models have stainless steel and which have carbon steel TSPs, and which are feed ring and which are preheat type models. At the time of this study twenty-one plants were using one of these W-models in their primary system loops. Braidwood 1 replaced all four SGs with Babcock & Wilcox Replacement RSGs. Indian Point 2 also recently replaced its four model 44 SGs with model 44F SGs. These two plants were not assessed by the WOG as part of this group.

Twelve of the 21plants in Table 5.1 have feed ring design SGs, with a total of 43 total individual SGs. The remaining 9 plants have preheat type SGs, with 35 individual SGs in service (Table 5.4). Seven plants (Callaway, Millstone 3, Salem 1, Seabrook 1, Vogtle 1 & 2, and Wolf Creek) have had model F units since their commercial start dates during 1977 - 1989. The original Salem 1 Model F mill-annealed 600 tube SGs were replaced in 1997 with Model F thermally treated 600 tube SGs removed from the cancelled Seabrook 2 plant. Another 12 plants (5 plants with replacement model 44F units, and 7 with original model F units) have quatrefoil broached hole type stainless steel TSPs.

Table 5.4 Distribution of SG Models 44F, F, D3, D4, D5, E2

SG Design Type	Model #	# of NPP Units	# of SGs
Feed Ring Models with SS TSPs:	Model 44F	5*	15
	Model F	7	28
Preheat Models with CS TSPs:	Model D3	1	4
	Model D4	2	7
	Model E2-TGX	1	4
Preheat Models with SS TSPs:	Model D5	4	16
	Model E2-THX	1	4
TOTAL	7 Models	21	78

* Excluding Indian Point 2, whose four model 44 SGs were replaced with model 44F in December 2000.

All nine plants with preheat design SGs have been operating since between 1986 to 1992. Watts Bar is the only plant which has model D3 SGs, and South Texas 1 & 2 are the only ones with model E2 SGs. At the time of this study Comanche Peak 1 and Shearon Harris had model D4 SGs (recently Braidwood 1 replaced its Model D4 SGs with B&W replacement RSGs). These three models (D3, D4, E2-TGX) have drilled hole carbon steel TSPs. Four other plants (Byron 2, Braidwood 2, Comanche Peak 2, and Catawba 2) with model D5 SGs have quatrefoil broached hole stainless steel TSPs. South Texas 2, with model E2-THX SGs, has round hole stainless steel TSPs. Sorted another way, there were four plants with drilled hole carbon steel TSPs, and 17 plants with stainless steel quatrefoil broached TSPs. All carbon steel TSPs had drilled holes, and all stainless steel TSPs, except at South Texas 2, have quatrefoil broached holes.

WCAP-15093 (Proprietary) and WCAP-15104 (Non-proprietary) present the WOG's evaluation of the impact of the causal factors of EdF SG Internals degradation on the W models in this group. In addition, these reports have a final assessment of these W models' susceptibility to deterioration of the secondary side internals and specific recommendations for future SG inspections to monitor internal components.

Model F (Ref. 25)

Seven plants have 28 Model F SGs. The feed ring type Model F steam generators with stainless steel TSPs started with the Callaway model F (Early Model) and ended with the Vogtle model F (Late Model) whose design included the following significant improvements:

(1) The Early Model has a flow baffle plate with patch plates incorporating rim cutouts for anti-rotation bars to be installed, while the Late Model has neither patch plates nor rim cutouts.

(2) The TSPs in the Early Model have patch plates and the Late Model does not. However, the Model F at Seabrook (and at Salem 1) has a single patch plate in the TSPs that is mechanically fastened;

(3) Although the wrappers of both models have similar forms, functions, and materials, there are significant differences on how they are assembled and supported within the vessel shell. The Early Model has long channel supports used to attach the wrapper to the SG shell; but, the Late Models do not have channel supports; and

(4) The wrapper cone assemblies are welded to the wrapper shell differently for these two models.

Model 44F (Ref. 26)

Model 44F is a feed ring type with stainless steel TSPs. Five plants have 15 Model 44F SGs. In addition, Indian Point 2 replaced its original model 44 SGs with model 44F units in December 2000. The first of the Model 44F designs was installed at Turkey Point 3 (1979) and the last at Indian Point 3 (1988). The significant change between them is that the flow distribution baffle ('A' Plate) at Turkey Point has two halves, while that for Indian Point is one piece. The tube holes in the flow distribution baffle also differ. The Turkey Point SGs has patch plates at one end of the tube lane but the plates are mechanically fastened to the TSPs. Other differences in design of the internal parts include variations in quantities, locations, length, and other such dimensions.

Model D (Ref. 27)

Seven plants have 27 Model D SGs. The Model D SGs (preheat design) include Westinghouse model designations D3, D4, and D5. The D4 and D5 SGs are sometimes further divided into D4-2 and D4-3, and D5-2 and D5-3. These designations were used to identify the variations in the design/manufacturing changes within the D-series and have no impact on this review. Both D3 and D4 models have carbon steel TSPs with round tube holes and utilize long channel supports. D5 models have stainless steel TSPs with broached tube holes and no channel support. Also, both D3 and D4 models have patch plates attached to TSPs with plug welds; D5 models do not have patch plates. Model D3 wedges are fillet welded to both the TSPs and wrapper on the top side of plates; Model D4 and D5 wedges are fillet welded to the wrapper alone on plate's top side.

Model E2 (Ref. 28)

The Model E2 SGs (preheat design) are used only at South Texas Unit 1 (model E2-TGX) and Unit 2 (model E2-THX). The former SGs have carbon steel TSPs and baffle plates, while the latter SGs have stainless steel TSPs and baffle plates. The TGX SGs have a flow baffle plate with patch plates, but the THX SGs have no patch plates. Both model wrappers are similar and use long channels, but the THX wrappers have many cutouts located over the segmented channel supports and the wrapper block openings.

For SG models with preheat design, the main feedwater is directed downward as it enters the water box area and is turned by the B baffle plate to enter the preheater. As the flow radiates from the impingement plate, the carbon steel support ribs are directly in the path of the flow. Four vertical support ribs are used in line with the SG vertical axis. The side ribs are perforated with two rows of 2.54 cm (1-inch) round holes on a 3.81 cm (1.5-inch) pitch while the top and bottom ribs have three rows of holes. The top and bottom ribs are taller than the side ribs since the distance from the impingement plate to the wrapper is the largest at the nozzle centerline. A perforated cap plate lies at the top of the impingement plate, perpendicular to the vertical support ribs, and closes the water box at the top.

SG Internals Degradation Experience and Evaluation

For the SG models in this group, 18 plants responded to the W survey; 17 of them have inspected or reviewed inspection data for TSP ligament crack indications for all 52 of their SGs. Sixteen plants have performed SG secondary side entries confirming no wrapper drop in 47 SGs. There is no report of any ligament damage nor indications in either the carbon steel (CS) or the stainless steel (SS) TSPs. The SGs with longer periods of operation have had more inspections and more opportunities for observation of indications. The surveys did not detect any of the several modes of degradation experienced in the EdF plants: no significant material losses after chemical cleaning, no wrapper drop, nor ligament cracking or thinning that is progressive and continuing either directly observed or implied by tube indications.

At Shearon Harris, tube wear was detected on several tubes in row 49 just above the B plate, on the cold leg side of one Model D4 SG. The foreign objects responsible for it originated from the erosion/corrosion on the vertical support ribs in the water box area where two cylindrical pieces were retrieved. No erosion/corrosion of the wrapper, impingement plate, target plate or impingement plate to target plate weld was seen. Westinghouse concluded that any rib pieces that separated from the water box would be small, and that the erosion/corrosion pattern occurring in the ribs will gradually enlarge the original 1" holes, so the affected flow holes would eventually coalesce.

In the feed ring SG design, thinning of carbon steel J-nozzles prompted some plants to replace them with alloy 600 J-nozzles which are more resistant to erosion-corrosion. In the preheat SG design, erosion-corrosion was observed on some vertical support ribs welded to the outside of the SG impingement plate in the waterbox area. In South Texas Unit 1 about 30 cm (12 inches) of the side ribs were eroded away, resulting in loss of the perforated structure with coalescence of the flow holes. The bottom row of the perforated holes was preferentially attacked toward the B plate as opposed to toward the cap plate. The circular shapes of the original 2.54 cm (one inch) holes, in the support ribs, were enlarged resulting in coalescence of the holes in the eroded missing length. The licensee finally stabilized the affected SGs by plugging several tubes. Eddy current testing (ECT) of peripheral and T-slot tubes within the preheater is being performed at each refueling outage (RFO).

At Watts Bar, one end of the blow-down pipe was severed in two Model D3 SGs. Further analysis indicated that overstress in the fillet weld where failure occurred was caused during the manufacture and hydro-testing of the SGs. Evaluation of the clearances and flow conditions showed that consequential damage to adjacent tubes is not expected since the flow velocities in this region are low and the clearances are large. We note the unique design of the blow-down pipe for the Model D3 SG; other preheat SG designs do not utilize a continuous blow-down pipe extending the length of the tube lane.

Several plants found small loose objects during FOSARs and removed them when possible. Many licensees used eddy current inspections to find loose objects. When loose objects can not be removed, their potential effects on the tube's integrity during subsequent operation are evaluated. If it can be reasonably determined that tube damage will not exceed the allowable limits of the technical specifications, the object may be left in place, and the condition of adjacent tubes checked at subsequent inspections.

Based on the survey results, erosion-corrosion in moisture separators and feed ring/J-tubes of model F and 44F and in the waterbox of models D3, D4, and E2-TGX were observed in some SGs. Also, cracking in transition cone girth weld of model F and 44F was observed in some SGs. The TSP ligaments and wrapper near supports of models F and 44F has low susceptibility to cracking. For models D3, D4, and E2-TGX, the moisture separators and the TSO flow holes/ligament are susceptible to erosion-corrosion, while the TSP ligaments are susceptible to cracking. The wrapper near supports and transition cone girth weld have low susceptibility to cracking. For models D5 and E2-THX, the moisture separators and the waterbox are susceptible to erosion-corrosion, while the TSP ligaments, the wrapper near supports, and the transition cone girth weld have low susceptibility to cracking.

The following are the types of SG internals degradation that may have safety concerns: loss of support in the tube bundle that potentially could lead to SG tube wear and possibly to primary-to-secondary leakage; TSP deformation during a postulated loss-of-coolant accident plus safe- shutdown earthquake (LOCA+SSE) event, resulting in a reduction inflow area and potential secondary-to-primary in-leakage; and, the generation of loose parts in the secondary side of the steam generator which may cause tube wear and possibly, primary-to-secondary leakage. Based on the design and operating experience, Westinghouse stated that various indications of TSP degradation may be artifacts of manufacturing anomalies related to patch plate plug welds and drilling alignment. Also, various W design features in SG internals are beneficial compared to the designs of some foreign manufacturers' SGs.

TSP ligament cracking, erosion-corrosion of the flow holes, and flow-assisted corrosion are the mechanisms of degradation identified in the EdF plants that may cause the loss of TSP integrity. The potential for tube vibration and wear from mechanical or flow-induced excitation was considered in the original design of W SGs. Lack of the presence of the TSP can be readily detectable through evidence of degradation in the tubes using eddy current techniques (ECT). For the two feed ring models F and 44F, W recommends a sample inspection of the top TSP and tube lane region (where there are flow holes instead of elongated slots).

W recommends that to preclude secondary-to-primary leakage during a postulated LOCA+SSE event, cracked tubes at the TSP intersections in the affected region of the tube bundle should be removed from service by plugging (or repaired with sleeves, if possible). Several plants have completed a plant-specific analysis to determine a more exact impact of LOCA+SSE loading on the collapse of tubes and the potential for secondary-to-primary in-leakage.

Loose parts or foreign objects have caused two of the SG tube rupture (SGTR) events in the United States. However, the majority of objects found have not seriously threatened tube integrity. NRC agrees with industry guidance that loose parts detected at any time should be removed from the SGs, if possible. For those that cannot be removed, evaluations should address the maintenance of SG tube integrity during subsequent plant operation. Westinghouse recommends planning a FOSAR of the top of the tube sheet region of the secondary side of the SG at a minimum. Tubes with visible damage should undergo eddy current tests and plugged if found defective.

Based on the W evaluation, all models of SGs in this group, are susceptible to the following types of damage that may cause loss of TSP's integrity:

(1) erosion-corrosion of the moisture separators and other steam drum components in all SG models,

(2) the potential to TSP flow hole erosion-corrosion applicable to SG Models D3, D4, and E2-TGX with CS TSPs and round flow holes,

(3) erosion-corrosion of water box internal components in the preheat design models (D3, D4, D5, E2-TGX, and E2-THX) and of feed ring and J-tubes in the feed ring design models (F and 44F),

(4) susceptibility to TSP ligament cracking near the wedge supports in Model D3 SGs,

(5) TSP ligament cracking near the patch plates in Models D3, D4, Early F, and E2-TGX SGs that have patch plates and plug welds securing them on the TSPs, and

(6) susceptible to cracking in the transition cone girth weld in Model 44F.

These items can be addressed by following the suggested W inspection guidelines discussed in Section 2.2.3.5.

No W SG models show susceptibility to wrapper drop or cracking at the lower support. W stated that there was no reported detection of missing pieces of TSP ligaments, nor instances of ligament indications for all the models in this group.

Westinghouse recommends inspecting Model D3 SG tubes every outage with a bobbin probe, and eddy current examination to detect any missing TSP.

Tube wear and primary-to-secondary leakage may occur due to loose object in the secondary side of the SG after erosion-corrosion of the moisture separators, of other steam drum components, of TSP flow holes, or after cracking of the TSP ligaments. If such leakage should occur due to tube wear from a loose object, W stated that the expected consequences would be bounded by a single tube rupture event and, therefore, would remain within the plant's licensing bases.

5.2.1 Susceptibility of the W SGs Relative to EdF and SONGS Experience

All plants in this group joined Westinghouse Owners Group's (WOG) effort to assess the susceptibility of tube damage or loss of DHR capability due to degradation of secondary-side components. EPRI's report, GC-109558, "*Steam Generator Internals Degradation: Modes of Degradation Detected in EDF Units,*" was used to evaluate the causal factors involved in the modes of degradation experienced in the French units. This report gave the WOG insights into the applicability of the EdF experience to their steam generator designs and operating history. Other attributes considered were design factors, fabrication and manufacturing techniques, and operating history, including chemistry and related degradation, such as denting. In addition, the WOG assessed industry-wide information on eddy current examinations, visual, video, and pertinent nondestructive examinations (NDE) made as part of the inservice inspection (ISI) experience to further enhance their evaluations.

This section presents the WOG's evaluation of the potential for the W Models F, 44F, D, and E2 SGs to undergo modes of degradation similar to those experienced in the EdF and SONGS plants.

(1) *Erosion of the top TSP due to improper placement of hoses during chemical cleaning:*

There is no evidence from post-chemical cleaning inspections of any significant material losses in the TSPs of the W SGs.

(2) *Ligament cracking of carbon steel with drilled hole TSPs due to mechanical loads during manufacturing, shipping, or early operations:*

The first type of ligament cracking was located at the top TSP (and, in one case, at the next to top TSP) near the long channel seismic support in EdF Model 51M SGs. It was later determined that the flow holes near the periphery might have weakened the TSPs in this model. The "one part" units, when subjected to stress relief of the vessel shell closure weld might have applied large mechanical overloads by the presence of the long channel support. Other possible causes of mechanical overloads include mechanical loads applied during fabrication, shipping, or installation due to an inadequate number of anti-rotation keys, and thermal expansion induced deformation of the full height channel relative to other parts during plant transients early in life.

The second type of TSP degradation includes indications in the vicinity of the patch plate plug welds. These include debonding between the weld material and the patch plate or TSP, and ligament failures at adjacent locations. In EdF 51A SGs, these ligament cracks were randomly distributed but in EdF 51M SGs, they were concentrated near the wedge region (primarily at the long channel support). The causes of damage are believed to be related to a faulty welding process and similar to the ligament cracking.

Westinghouse stated that no TSP ligament cracking in this series of W SGs is reported as progressive and continuing, either directly observed or implied by tube indications. From technical evaluation of the plate load carrying capability, Models D3, D4, and E2-TGX SGs have TSPs with lower normalized strength than the EdF 51M model, and Models D3, D4, both E2 and 44F have TSPs with lower normalized strength than the EdF 51A. Model D3 SGs at Watts Bar have similar design features as the EdF models (i.e., the wedges are welded to both the wrapper and the TSPs) and could be susceptible to TSP cracking away from patch plates, as in the EdF 51M SG. Other W models (F, 44F, D4, D5, E2) have wedges welded to the wrapper alone and therefore, do not appear to be susceptible to cracking near the wedge groups.

Models Early F, D3, D4, and E2-TGX have patch plates and plug welds and indications near patch plate plug welds. The first Model 44F SGs at Turkey Point 3 have patch plates at one end of the tube lane, but the plates are mechanically fastened to the TSPs. Also, the Model F SGs at Seabrook have a single patch plate in the TSPs that is mechanically fastened. The SGs in Late Model F, Model 44F from Turkey Point 4 forward, Model D5, and Model E2-THX do not utilize patch plates.

(3) *FAC-induced thinning of the top TSP periphery due to ammonia water chemistry:*

Carbon steel TSP material is known to be subject to FAC-induced degradation. It is considered to be associated with a local pH environment (i.e., low hydrazine concentration and operation with ammonia at low pH) that is detrimental to the carbon steel material in EdF plants. EdF SGs that abandoned ammonia chemistry before about 1985 have suffered no material losses.

Westinghouse has no reports of TSP ligament thinning that is progressive and continuing, either directly observed or implied by ECT indications. With the use of EPRI guidelines since 1982, FAC in the Model 51 series with carbon steel TSPs has not been observed. Therefore, WOG stated that the models in this group also are not susceptible to this degradation. Moreover, plants have not reported FAC-induced thinning in their SGs.

(4) *Wrapper-drop due to fatigue failure of supports:*

EdF Model 51B and 51BI SGs were the only SG models found to have dislocated wrappers in three SGs at two plants. The design of the TSP to wrapper joint of these SGs is unique; they do not have an inclined plane in the wedges between the TSPs and the wrapper. The wedges are not welded to both the TSPs and the wrapper, as they are in models EdF 51A and 51M. There are no backup bars to transfer vertical loads (weight) to the tie rods. Therefore, these EdF SG models experienced wrapper drop when the wrapper to shell supports lost their structural integrity.

Unlike the above EdF models, all W models in this group have features that prevent any wrapper drop if the wrapper supports fail in the U.S. SGs. W noted that if there was wrapper drop, it would be detected during attempts to insert FOSAR equipment. No obstructions FOSAR or sludge lancing equipment by the wrapper have been identified during routine inspections at each RFO. Therefore, it was concluded that there is no evidence for wrapper drop in U.S. plants.

(5) Fatigue cracks from support blocks due to flow-induced vibration of the wrapper:

The failure of weld joints of the lower wrapper supports are presumed to be caused by thermal transients between the wrapper and the shell due to tight clearances between adjoining non-welded parts, to flow-induced vibration of the wrapper assembly, and to poor quality welds.

Westinghouse stated that the welds in the lower support blocks in all W models in this group are of superior quality, and that they have little tendency to exhibit wrapper flow-induced vibration. Wrappers have only cracked in those EdF units where the wrappers have dropped.

Unless there is an indication of a wrapper's misposition by interference with the sludge lancing equipment at the entry port, no licensee plans to inspect the wrapper support blocks. Thus, while there was no evidence of wrapper cracking or support block wear in any plant, none indicated that they specifically inspected for it.

(6) TSP wedge block cracking:

The wedges of EdF 51M SGs are welded to both the wrapper and to the TSP with fillet welds under the TSP. Similar to the TSP ligament cracking in item (2) above, tensile loads can be transmitted from the long channel, or other channel, through the wrapper and wedges to the TSP ligaments, and also be reacted to on the opposite periphery. There is a reported trend that where the wedge group welds are smaller, there is less tendency for TSP ligament cracking, and more tendency for the fillet weld to crack. The converse also is reported to be true. Since this cracking has no safety significance, determining a root cause was not considered important.

Westinghouse has not addressed this particular degradation mechanism; however, only the Model D3 SGs (at Watts Bar) have these wedge block welds attached to both the TSPs and the wrapper. Therefore, only these SGs will be susceptible to cracking under tensile overloads. This is discussed further in the next section.

(7) Eggcrate support degradation at SONGS due to FAC associated with fouling:

None of the licensee's submittals nor Westinghouse have addressed this particular damage. However, FAC associated with fouling has not been reported in any of the W SGs.

In summary, these assessments provide reasonable assurance that the integrity of the steam generator tubes and DHR capability are not compromised by degradation of SG internals.

5.2.2 Responses to NRC's Generic Letter 97-06

Table 5.4 shows that the 21 NPP units in this group at the time of this study had 78 SGs spread among seven different models. The 15 Model 44F SGs with stainless steel (SS) TSPs are all replacement units installed in 5 plants during 1981-1989. The remaining 63 SGs in 16 plants were the original units consisting of W models 44, F, D3, D4, D5, and E2. Braidwood 1 replaced its four model D4 SGs with BWI design units in November 1998. Salem 1 replaced its SGs with four model F units from the canceled Seabrook 2 plant in July 1997. South Texas 1 replaced its four model E units in May 2000. J-nozzles made of more corrosion resistant materials were installed in Turkey Point 3 and 4 during 1989 and 1990, respectively.

Most licensee's responses addressed the information requested in the GL. The WOG discussed the applicability of the EdF failure modes to these SG models in WCAP-15093 and WCAP-15104. No plant has addressed the SONGS experience relating to FAC at the periphery of TSPs since W SGs do not have eggcrate TSPs. Most plants in this group appear to perform FOSAR and sludge lancing every RFO; very few have chemically cleaned their SGs. The WOG gave recommendations for inspections. All plants have performed some secondary side inspections, however, details on the type, scope, and frequency of future inspections were not generally provided.

All plants employ some type of visual and/or remote camera inspection of the upper package of SG internals, which includes the steam drum, moisture separators, feed ring with associated components (e.g., J-tubes, CS feed ring adjacent to the J-tubes, T-section, reducers, backing rings, and the thermal sleeve), and the preheat waterbox area. The transition cone girth weld and other feedwater nozzle welds are regularly inspected following ASME Section XI requirements. The degradation mechanisms associated with wrapper drop and wrapper cracking are verified only if there is an interference of the sludge lance equipment. No inspection is performed unless there is evidence of the wrapper misposition or tube damage in the periphery of the first TSP. If detected, the lower wrapper support blocks are visually inspected. Plants have either implemented the inspection recommendations delineated in WCAP-15031, or are planning to do so, as appropriate to their SGs.

Based on the WOG survey of these plants and plant-specific inspection findings, there is no evidence of post- chemical cleaning inspections discovering any significant material losses. In addition, no evidence of any wrapper drop has been noted. Indications of TSP ligament cracking or missing pieces of ligaments were observed only in units with carbon steel TSPs which have drilled round holes and flow holes. However, these conditions are generally traceable to initial inspections, or are not progressing based on sequential inspections. Many of these conditions are believed to be related to drilling misalignments during manufacturing. Many cases of indications detected by the eddy current examinations are linked to patch plate plug welds.

All plants have made visual/video inspections of their tube bundles and other SG internals and found no significant degradation in any component. The licensee of one plant replaced its CS J-tubes with replacement parts more resistant to erosion-corrosion. Although it is not clearly stated, we believe that all plants perform FOSAR and sludge-lancing operations on each SG unit during every refueling outage (RFO) as part of their maintenance activities. Some have found loose objects that have been either removed from the SG, or left inside in such a manner as to mitigate their potential effect on tubes or other internal components.

The six plants with carbon steel TSPs stated that they perform eddy current inspections to monitor previous indications and have identified none that were progressing. The SGs with stainless steel TSPs in the other 17 plants have quatrefoil broached hole design; eddy current detection of potential ligament cracking or indications is generally not applicable although ECT can ascertain the correct position of the TSPs. Thus, few plants with SS broached hole TSPs have performed any assessment of their past ECT data. Only South Texas 1 has completed a one-time inspection of 100% of the tubes to satisfy the WOG recommendation. Table 5.5 summarizes the inspection findings from all plants in this group based on the information in their submittals.

Table 5.5 Plant-specific Inspections For W SGs, Models 44F, F, D3, D4, D5, and E2

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Byron 2	Performed for TSP location	No missed location	Visual and video inspections	No significant degradation noted	FOSAR/Sludge-lancing each RFO. Has a program for SG internals.
Braidwood 1	Performed for TSP degradation	No degradation noted	Visual and video inspections	No significant degradation noted	FOSAR/Sludge-lancing each RFO. Has a program for SG internals.
Braidwood 2	Performed for TSP location and preheater loose part	No abnormality noted	Visual and video inspections	No significant degradation noted	FOSAR/Sludge-lancing each RFO. Has a program for SG internals.
Callaway	Not stated	-----	Visual and video inspection	No degradation noted	FOSAR each RFO
Catawba 2	Performed for TSP locations	No missed location	Visual inspection	No degradation noted	FOSAR/Sludge-lancing each RFO.
Comanche Peak 1	Performed for TSP degradation	No degradation noted	-----	No wrapper misposition	Sludge-lancing
Comanche Peak 2	Not stated	------	Visual and video inspection	No degradation noted	Sludge-lancing performed during 3rd RFO

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
Shearon Harris	Performed for TSP degradation	No degradation noted	Visual inspection	Loose parts in the preheater of SG-A	FOSAR/Sludge-lancing each RFO.
Indian Point 3	Not stated	-----	Visual and video inspections	No degradation noted	Only two SGs inspected. The other two are scheduled for next RFO.
Millstone 3	Performed to detect missing TSP or parts	No missing parts noted	Visual and video inspections	No degradation noted	FOSAR/Sludge-lancing performed
Point Beach 1	Not stated	-----	Visual and video inspections	No degradation noted	FOSAR/Sludge-lancing each RFO.
Robinson 2	Not stated	-----	Visual inspections	No degradation noted	Plan to inspect one SG each RFO on a rotating bases.
Salem 1	Not stated	-----	Visual and video inspections	No degradation noted	FOSAR performed during replacement.
Seabrook 1	Not stated	-----	Visual and video inspections	No degradation noted	FOSAR each RFO.
South Texas 1	Performed for TSP conditions	No degradation noted	Visual and video inspections	Erosion of flow holes in the waterbox area	Has a program for SG internals.
South Texas 2	Not stated	-----	Visual and video inspections	No degradation noted	Has a program for SG internals.
Turkey Point 3	Performed for TSP locations	No missing location noted	Visual and video inspections	No degradation noted	FOSAR each RFO.
Turkey Point 4	Performed for TSP locations	No missing location noted	Visual and video inspections	No degradation noted	FOSAR each RFO.
Vogtle 1	Not stated	-----	Visual and video inspections	No degradation noted	FOSAR each RFO.
Vogtle 2	Not stated	------	Visual and	No degradation	FOSAR each RFO.

Plant Name	Steam Generator Operating Experience				Remarks
	Eddy Current Examination		Visual/Video Inspection		
	Methods	Findings	Methods	Findings	
			video inspections	noted	
Watts Bar	Performed for TSP degradation	No degradation noted	Visual and video inspections	Blowdown pipe severed	Sludge-lancing performed.
Wolf Creek	Performed for TSP locations and loose parts	No missing parts noted	Visual inspections	No degradation noted	FOSAR each RFO.

NOTE: Shaded plant (Braidwood 1) is not included in the WOG evaluation for this SG group for the reasons stated earlier.

5.2.3 Summary and Conclusions

As part of the WOG Steam Generator Internals Degradation Program, Westinghouse undertook a detailed evaluation of the potential for the W SG Models F, 44F, D series and E2 to experience modes of degradation similar to those in the EdF plants. W used other attributes, such as design details, fabrication and manufacturing techniques, and plant's operating history. In addition, the WOG compiled an industry-wide survey of SG operating experience and assessed the ECT, FOSAR, and other SG cleaning data from licensees. The overall conclusion was that WOG members with W SG models in this group can maintain operability through their normal ECTs and FOSARs and defined inspections. The causal factors identified by EdF do not affect the continued operation of these W models. Eddy current inspection of the tubes would detect detrimental effects on the tubing due to wear caused by TSP ligament degradation, loose parts, or changes in secondary flow distribution. The FOSAR inspections would discover loose parts that might cause wear in SG tubes.

W stated that the industry survey did not report finding the several modes of degradation experienced in the EdF plants. There was no report of post-chemical cleaning inspections discovering any significant material loss. There was no report of TSP ligament cracking or thinning that is progressing and continuing, either directly observed or implied by tube indication. Finally, there was no report of any wrapper having dropped nor of cracking of the wrapper at the lower supports in W SGs.

Tube wear and primary-to-secondary leakage due to the presence of a loose object on the secondary side of the SG may occur due to erosion-corrosion of the moisture separators, other steam drum components, or TSP flow holes, or to TSP ligament cracking. If such leakage should occur due to tube wear from a loose object, W stated that the expected consequences would be bounded by a single tube rupture event and, therefore, would remain within the licensing bases of a plant. The NRC agrees with industry guidance that loose objects should be monitored using eddy current examinations and FOSAR inspections to ensure maintenance of tube's integrity during subsequent plant operation.

Inspection guidelines recommended by Westinghouse for each SG Model are comprehensive, address these types of degradation, and licensees should consider implementing them. Model D3 SGs at Watts Bar are susceptible to wedge block cracking as well as TSP ligament cracking similar to that experienced in EdF plants. However, based on the EPRI's evaluation, such cracking does not appear to threaten tube integrity. Westinghouse has not recommended any inspection guidelines for these wedge blocks. As point of note is that neither the WOG's report nor the individual licensee responses have addressed the SONGS experience relating to the FAC associated with fouling. However, there is no indication of fouling in any of the W models reported by the licensees and, in contrast to eggcrate TSPs, the robust design of TSPs in these models enables them to withstand significant FAC before affecting the safety functions of the steam generators.

All plants in this group have some program in place to inspect for degradation in SG tubes and other internal components. Based on the recent WOG effort, many have adopted their recommendations for inspecting SG internals to address the EdF causal factors, or are planning to adopt them as appropriate to their SGs.

Based on the licensee submittals for the GL, the four plants with Models D3, D4, and E2 SGs, that had carbon steel drilled holes and flow holes, had no TSP ligament cracking nor missing pieces of ligaments. The other 17 plants in this group have stainless steel broached quatrefoil TSPs, and have not found any evidence of degradation. All have reported no significant degradation in any of their SG internal components, except a few who have replaced their carbon steel J-nozzles with newer ones made of more corrosion-erosion resistant materials. Plants with preheat design have found some loose parts caused by erosion-corrosion in the waterbox area.

Although all have not confirmed it, we believe that each plant undertakes FOSARs and sludge-lancings during each RFO. In addition, plants with carbon steel TSPs perform eddy current testing routinely each RFO to detect any new TSP degradation or to monitor existing TSP indications. Most plants with stainless steel broached hole TSPs perform eddy current testing and visual inspections for TSP locations. As mentioned earlier, most plants have augmented their existing inspection programs with additional examinations as recommended by the WOG. It is concluded that plants performing the inspection activities discussed above each RFO should be able to avoid problems stemming from degraded SG internals.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees have implemented or plan to implement, as appropriate to their SGs, their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

5.3 Indian Point 2 with W-Designed Steam Generators

At the time of the GL 97-06 issuance, Indian Point 2 (IP2) had feed ring model 44 SGs which were in service since the commercial start of IP2 in 1974. They were manufactured with mill-annealed alloy 600 tubing, carbon steel tube support plates with drilled holes, and partial depth rolled joints in the tubesheet. Early in the operating life of the IP2 SGs during the mid-seventies, general corrosion of the carbon steel TSPs and tubesheets resulted in a buildup of corrosion products in the annulus between the tubes and the TSP, and/or between the tubes and the tubesheet. This buildup squeezed the tubes enough to cause their permanent, plastic deformation at the TSP and tubesheet areas. As a result, all four SGs at IP2 experienced significant deformation of the tubes, commonly referred to as "denting." By enhancing the quality of the secondary water and implementing other mitigating actions, the licensee managed to bring tube denting largely under control. However, this denting led to extensive in-plane deformation in the TSPs and cracking of the TSP ligaments. One manifestation of TSP deformation was the distortion of the initially rectangular flow slots located along the open lanes separating the hot- and cold-leg of the tube bundle. The deformation in the TSP transformed the shape of the rectangular flow slots into hourglass shaped ones, typically referred to as "hourglassing." Much of this deformation process at IP2 probably occurred before 1984 and was readily visible during each subsequent inspection outage.

To ensure that the NRC's staff would be alerted to any significant change in the status of denting or hourglassing of the uppermost TSPs, several requirements were added to IP2's technical specifications. Through several inspection efforts and subsequent staff interactions with the licensee that occurred in the late 1970s and early 1980s, some of these added requirements specified that the licensee must (1) provide an evaluation to address the long-term integrity of small radius U-bends beyond row 1 within 60 days of any significant hour-glassing of the upper support plate flow slots, (2) report a significant increase in the rate of denting, and (3) plug tubes that do not permit passage of a 1.55 cm (0.610 inch) diameter probe. Throughout the 1980s and 1990s, the licensee performed its SG inspections in accordance with the above long-standing criteria; section 5.3.1 discusses the results of these inspections submitted by the licensee in response to GL 97-06.

The licensee had been visually inspecting SGs 22 and 23. SGs 21 and 24 did not have access ports permitting visual inspection of the uppermost TSP flow slots. Based on the inspection of SGs 22 and 23, the licensee reported no significant "hourglassing" of the flow slots in the uppermost TSPs. In addition, the licensee inspected the lower TSP flow slots of all four SGs using a video camera through the hand holes above the tubesheet and reported no change in the amount of hourglassing present at the lower TSPs. However, one flow slot at the second TSP showed closure which the licensee evaluated and determined to be acceptable.

W stated that the EdF experience was not related to TSP degradation at Indian Point 2 that progressed to the tube-denting stage in these four model 44 SGs, and so the effects of tube denting have not been addressed by either of the two WOG evaluation reports. Another five plants (Indian Point 3, Point Beach 1, Robinson 2, Turkey Point 3 & 4) used to have the older feed ring SGs from their commercial start date in the 1970s. They either replaced them entirely (Indian Point 3), or replaced the tube bundle part of the model 44F SGs during the eighties.

5.3.1 Evaluation of Licensee's Responses to GL 97-06

Susceptibility of the W Model 44 SGs Relative to EdF and SONGS Experience

Based on the plant submittal, the types of deterioration of secondary side internals found in Westinghouse 51 series steam generators with drilled carbon steel support plates are similar to model 44 SGs at Indian Point 2 because both models have similar design features. Therefore, the susceptibility evaluation for secondary side internal degradation in W models given in Section 5.1 is applicable to the Model 44 SG design, as well.

The WOG made a safety assessment of 51-series and 44-series SG designs. They recommended all utilities with these SGs with carbon steel support plates inspect a significant percentage of SG tubes every outage. WOG concluded that eddy current inspection, FOSARs during each RFO, and loose parts monitors should ensure that tube integrity is maintained during subsequent plant operation.

Results of the Examinations Performed during the 1997 RFO for IP2

Upper Support Plates: Steam generators 22 and 23 were visually inspected using a videoscope through the hillside port in the SG shell. There was no significant hour-glassing of the flow slots in the upper most TSP. The wedge locations were intact. The tube surfaces, flow holes, and the TSPs appeared to be normal.

Flow Slot and Lower Support Plate: All four SGs were video taped through the lower handholes. Compared with previous results, the "hour-glassing" of the flow slots in the lower TSPs had not changed. However, the photographs revealed cracks in the TSP at some flow slots. The upper TSPs had new small cracks, while there was no significant change in the general flow slot cracking previously observed.

Wrapper: Baseline measurements of the height of the wrapper above the tubesheet were consistent for all four SGs.

Secondary Side Examination: A Foreign Object Search and Retrieval (FOSAR) was conducted around the annulus and within the tube bundle in all SGs. Several items were subsequently removed which previously could not be removed. Wear rates on adjacent tubes were evaluated for the remaining objects. The growth of eddy current indications from the previous outage were evaluated to assess the contribution of loose objects to tube wear. Finally, it was found that SGs could be safely returned to service with the remaining loose objects without changing the Technical Specification.

Inservice Inspection Plan

The licensee stated that the WOG's inspection plan (Table 2.4) was implemented at Indian Point 2. Inspections were conducted every RFO in accordance to EPRI's SG Examination Guidelines (Rev.5). The scope and frequency may be adjusted based on site specific experience and evaluation of industry results of these inspections. It is presumed that the inspection plan for the replaced W model 44F should be updated in accordance with the recommendations given in Table 2.7.

5.3.2 Evaluation of Recent SG Tube Failure

During the SG inspection in May 1997, IP2 reported the following active degradation mechanisms in the SGs: wear at the anti-vibration bars (AVBs); outside-diameter stress corrosion cracking (ODSCC) and pitting in the sludge-pile region (i.e., the area above the top of the tubesheet and below the first TSP); ODSCC and intergranular attack (IGA) in the tubesheet's crevices; and primary-water stress corrosion cracking (PWSCC) at the tubesheet roll transitions and low row U-bend. This was the first time that PWSCC was identified in the low row U-bends. During subsequent plant operation the licensee detected a primary-to-secondary leak through the SGs by sampling condenser off-gas, tritium surveys, and/or other monitoring methods. This leak rate slowly increased from 1.9 liters per day (lpd) (0.5 gallon per day (gpd)) in September 1998 to 11 to 15 lpd (3 to 4 gpd) in January 2000. On February 15, 2000, IP2 was shutdown due to excessive leakage from tube R2C5 in SG 24. After extensive studies on the root causes of this incident, the licensee recently replaced all SGs with model 44F containing thermally treated alloy 600 tubing (Ref. 30). This section discusses the findings of the post-event investigation by the licensee to determine the root cause(s) of the tube failure and the staff's evaluation of, and conclusions about, this incident as they relate to SG internals degradation.

As part of the licensee's post-shutdown evaluation in 2000, eddy current testing was used to examine the SGs, in a similar location to failed tube R2C5 in SG 24. Rows 2 to 4 from the sixth (i.e., top) hot leg TSP to the sixth (i.e., top) cold leg TSP were examined, and the licensee found seven additional PWSCC indications in the apex region of the row 2 U-bends. (Row 1 was plugged prior to IP2 operation.)

As discussed earlier, IP2 experienced denting early in its operating life in the mid-1970s. This denting led to extensive in-plane deformation of the TSPs and cracking of support plate ligaments. Hourglass deformation of the uppermost TSP flow slots was known to have potential tube integrity significance. Such deformation causes the legs of the small radius U-bends to displace inward, substantially increasing the stress level at the apex of the U-bend and thus causing the potential for stress corrosion cracking at that location. This phenomenon led to a rupture of an inner row U-bend at Surry Unit 2 in 1976. The amount of hourglass deformation of the adjacent flow slot at Surry Unit 2 was 3.3 cm (1.3 inches). Accordingly, the licensee for IP2 had routinely performed visual inspections of the three flow slots in the uppermost TSP in SGs 22 and 23. Based on these visual inspections, the licensee did not identify hourglassing at the upper TSPs and, therefore, consistently reported through the years that the uppermost TSPs were free of significant hourglass deformation. SGs 21 and 24 did not have access ports permitting visual inspection of the uppermost TSP flow slots.

Secondary side visual examinations, including the FOSAR (foreign objects search and retrieval) inspection, were performed after the event in 2000 for monitoring the condition of the SG internals. Following the failure of R2C5 in SG 24, the licensee installed access ports in SGs 21 and 24 to permit visual inspection of three flow slots in each of these SGs, including the flow slot adjacent to R2C5 in SG 24. The visual inspections, performed with a video camera, did not provide clear indication of hourglass deformation of the upper TSP flow slots due to limitations presented by camera angle and lighting. After mounting a measuring device to the camera assembly, the licensee determined that hourglass deformation was in fact present in the flow slot adjacent to R2C5 in SG 24. The amount of hourglass deformation was 1.16 cm (0.47 inch), relative to the nominal flow slot width of 7 cm (2.75 inches). This amount of hourglassing at the uppermost TSP flow slots displaced the legs of the small radius U-bends inwards, and was sufficient to substantially increase the stress level at the apex of the U-bend, thereby enhancing the susceptibility of this location to stress corrosion cracking there. From further investigations, the staff concluded that the hourglass deformation of the uppermost TSP flow slots was occurring during most of the life of all four SGs at IP2. Previous inspections were inadequate for detecting this hourglass deformation.

Apart from flow slot hourglass deformation, visual inspections were also conducted after the 2000 event to assess the general condition of the TSPs and SG wrapper. Where accessible to the video camera, in-plane deformation (growth) of the TSPs, due to denting, was observed to have caused the support plates to be in contact with the wrapper, except in the near vicinity of the wedge supports. The reaction loads at the periphery of the TSPs maintained the plates in a high state of compression and the licensee, based on a detailed structural analysis, demonstrated that they were still capable of providing adequate lateral support to all unplugged tubes under operating and postulated accident conditions. All wedges and welded connections were observed to be in good condition. The licensee reported that there was no visible deterioration of the wrapper and the wrapper had not dropped from its earlier position.

In summary, the induced stress levels of the uppermost TSP flow slots due to hourglassing of the uppermost TSP was a primary contributor to the development of PWSCC in the apex region of seven Row 2 steam generator tubes identified during the 2000 inspection. One affected tube (R2C5) failed at normal operating temperatures and pressures, causing excessive operational leakage which led to the February 2000 shutdown. Past inspections in SGs 22 and 23 are inconclusive regarding how long the upper flow slots have experienced significant hourglass deformation. (Significant deformations is used here in the context of causing sufficient stress over time and at operating temperatures to cause PWSCC.) Therefore, the licensee's inspections of the upper TSP flow slots, dating up to the tube failure in February 2000, were inadequate for purpose of detecting significant hourglass deformation.

5.3.3 Summary and Conclusions

The licensee replaced its all four model 44 SGs with model 44F SGs in December 2000. The current SG internals inspection activities for the model 44 SGs should be updated for the model 44F SGs, as discussed earlier in Section 5.2.2.

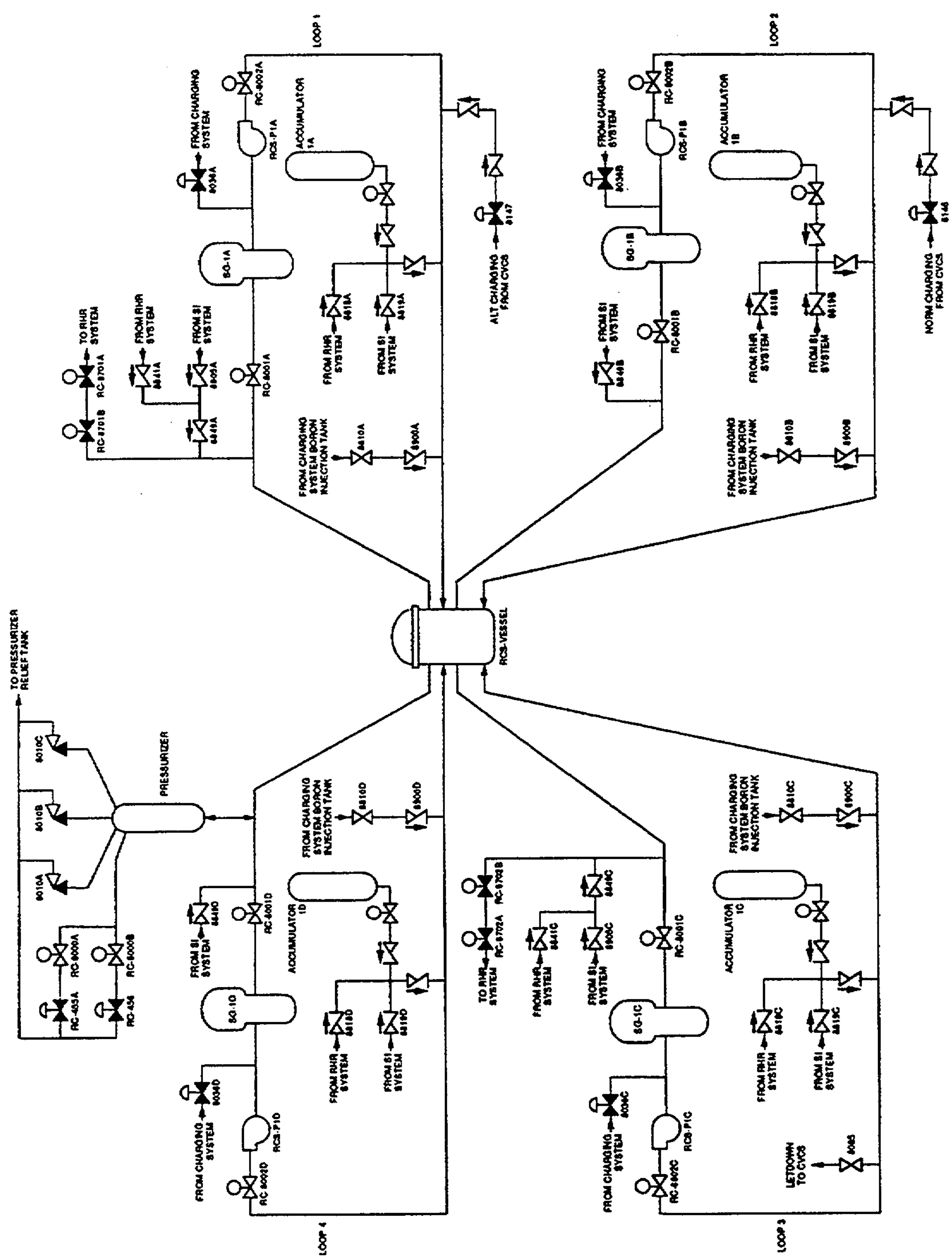

Figure 5.1 Braidwood Unit 1 Reactor Coolant System (4 Loops)

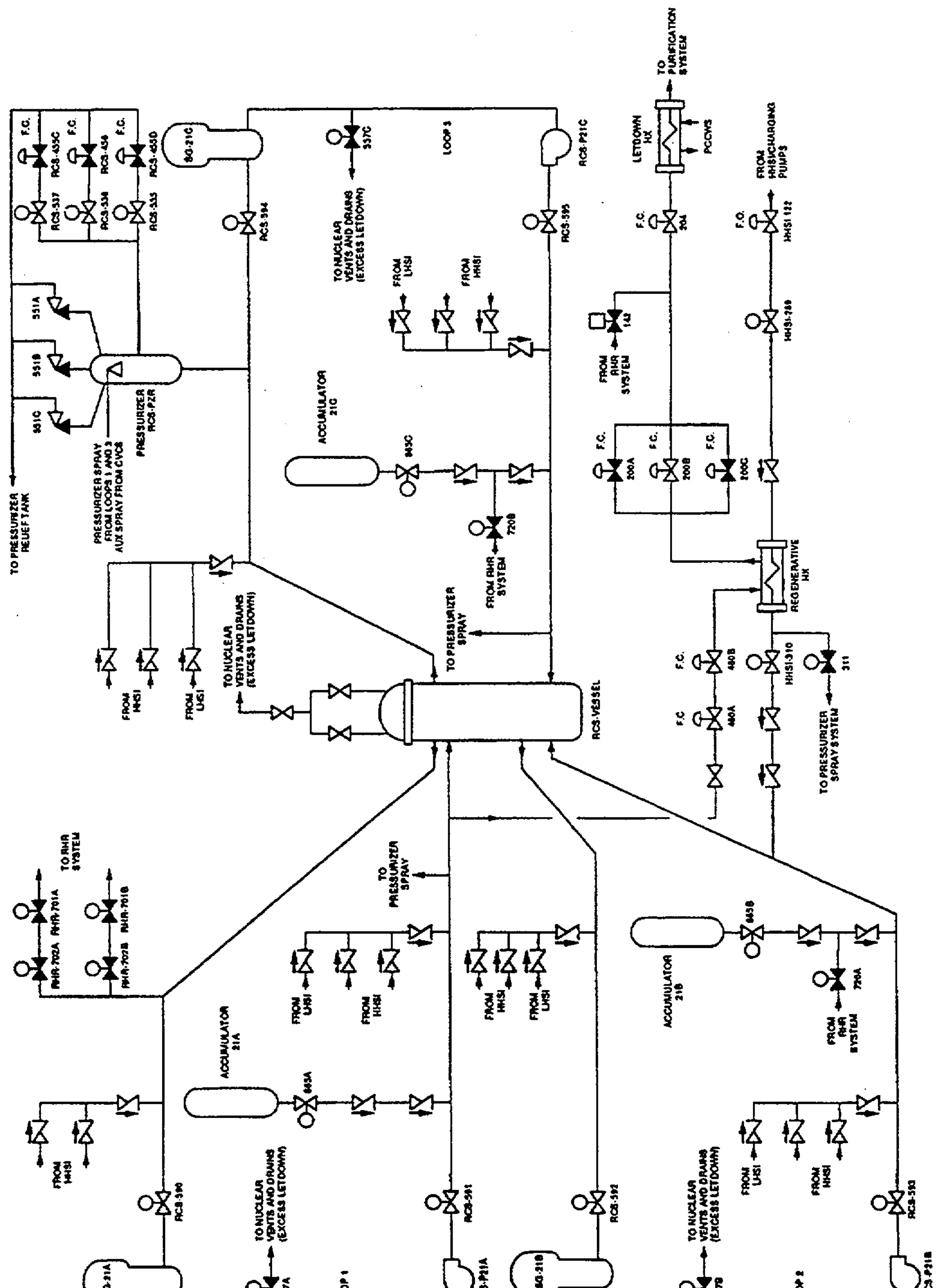

Figure 5.2 Beaver Valley 2 Reactor Coolant System (3 Loops)

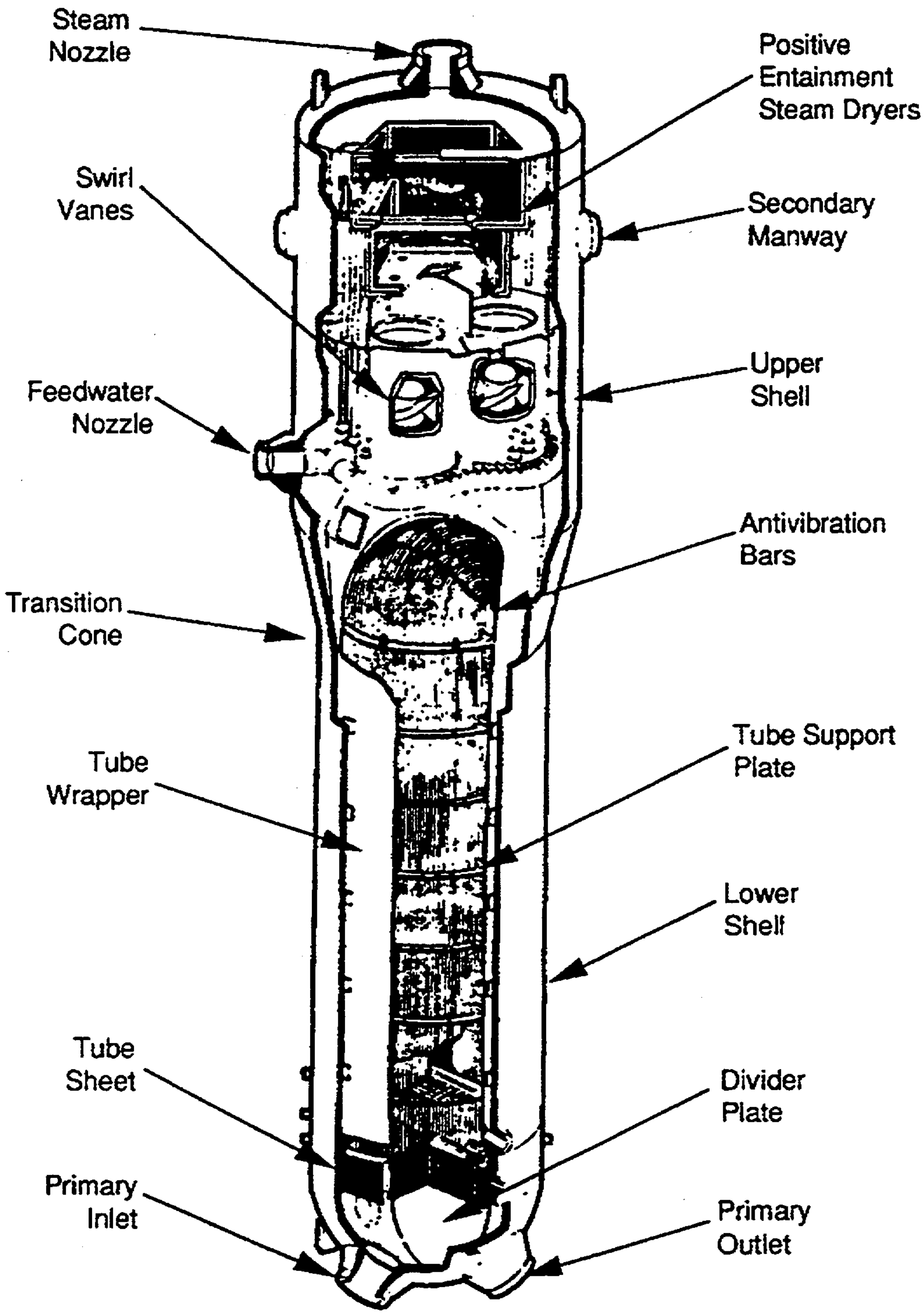

Figure 5.3 Westinghouse Recirculating Steam Generator (Typical of Models 44 and 51)

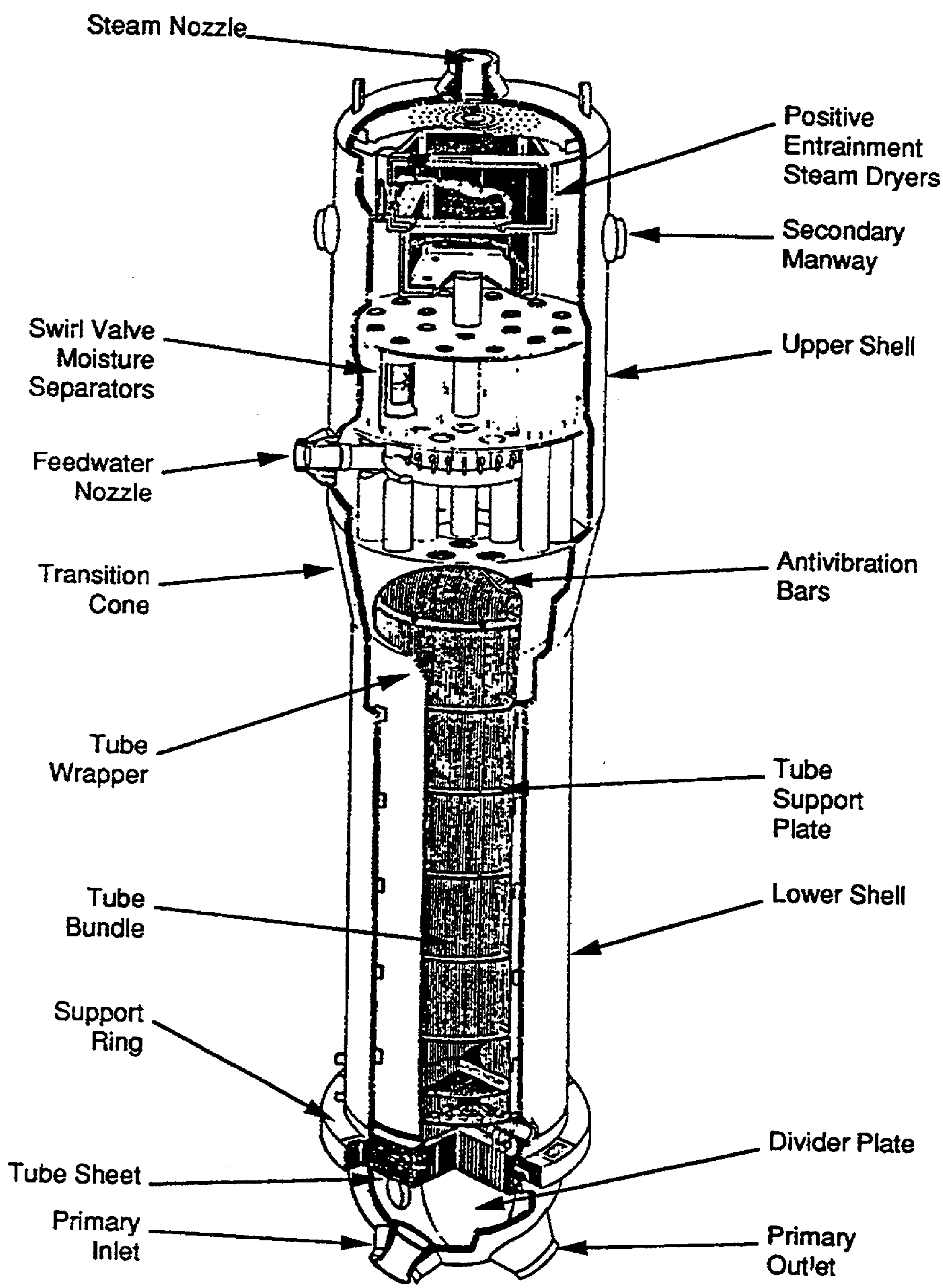

Figure 5.4 Westinghouse Recirculating Steam Generator (Typical of Model F)

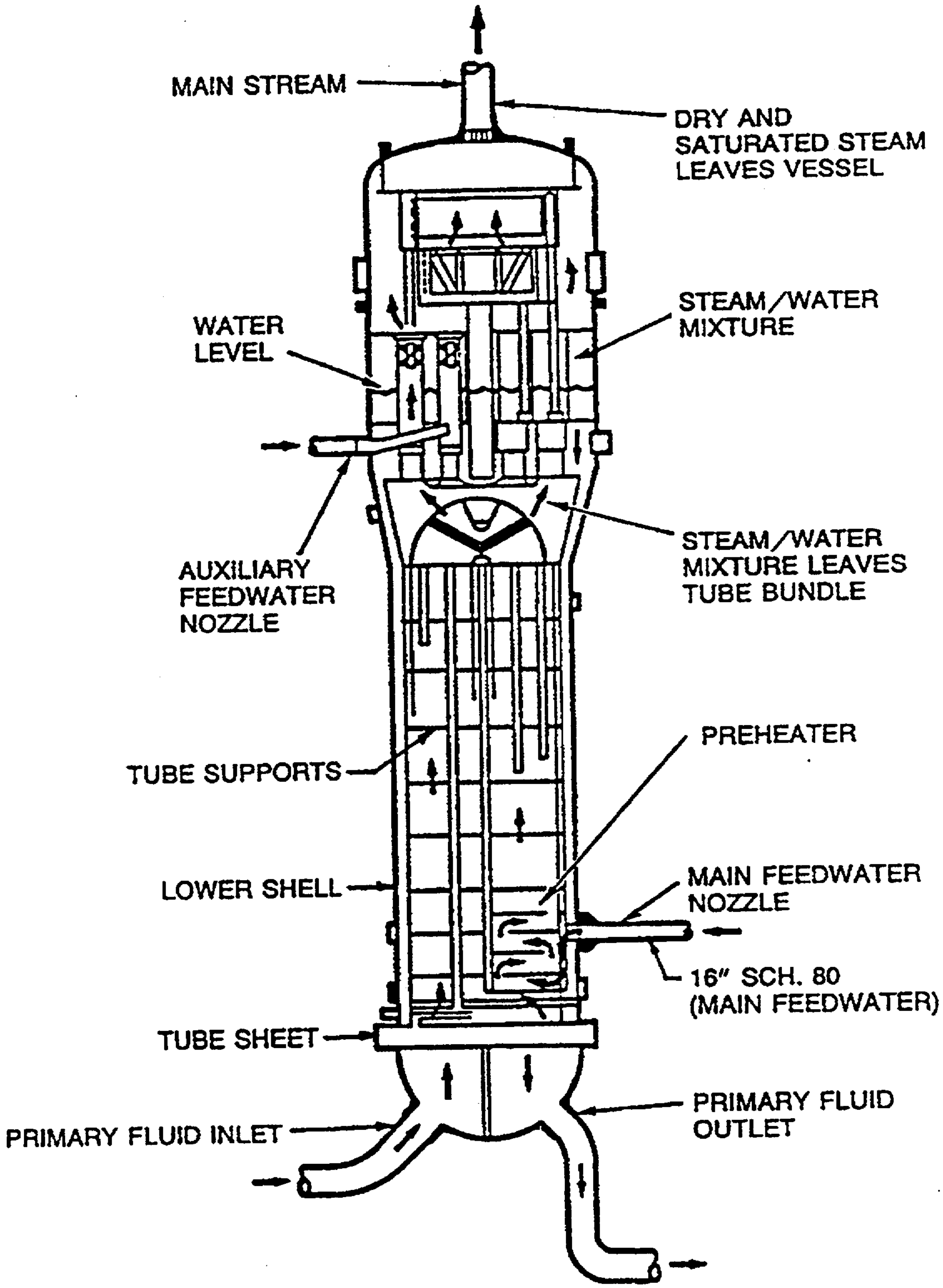

Figure 5.5 Westinghouse Recirculating Steam Generator (Typical of Model E Preheat Unit)

6 SUMMARY AND CONCLUSIONS

6.1 Summary of Results

The results presented in this report are based on the following documents: the licensees' submittals in response to GL 97-06; EPRI report on the modes of degradation detected in SG internals; owners group reports on the evaluation of the EdF causal factors and the degradation at SONGS; owners group response to NRC's requests for additional information (RAIs); and limited discussions with steam generator (SG) manufacturers. In addition, NEI 97-06, "Steam Generator Program Guidelines," and related EPRI documents were reviewed. This report and the summary relate to SG secondary side internal components; the report does not focus on the SG tubes themselves.

The technical work on this review was completed in the Fall of 1998. At that time, the owners groups' assessments, while completed in some cases, were still listed as interim; in other cases, they had not been completed. The Westinghouse owners group evaluation of its SG models F, 44F, D and E2 were completed in December 1998. The Babcock & Wilcox owners group report on once-through steam generators internals was completed in February 1999. Thus, the final evaluations of all degradation identified in the GL for these SGs became available during the Spring of 1999. Most plant submittals are based on the owners group reports and past inspections of their steam generators. The Nuclear Energy Institute (NEI), who coordinated the industry's response to this GL, incorporated in its "Steam Generator Program Guidelines" a requirement to monitor secondary side SG components if their failure could prevent the SG from fulfilling its intended safety-related function.

Degradation problems in steam generator tubes have been known in the nuclear industry from the mid-seventies and there are several Electric Power Research Institute (EPRI) guidelines on maintaining the structural integrity of *SG tubes*. However, there existed no explicit industry guidelines for an *SG secondary side internals* inspection program. Many of the reported activities in this area by the licensees resulted from self-identified problems over the past 25 years of service. In response to the GL, the owners groups identified additional SG internal components that could be vulnerable to degradation, and suggested inspection guidelines to address these concerns.

NEI 97-06 describes a program to ensure the operability of steam generators, and includes prevention, inspection, evaluation, repair, and leakage monitoring. NEI 97-06 provides an approach for an SG secondary side program, which in turn has to be combined with the SG-specific inspection guidelines and analyses, as suggested by the SG owners groups.

The findings from our review of licensees' submittals and associated documents are summarized as follows:

- All US PWR plants have, or plan to have, an inspection program to detect and monitor degradation of SG internals.
- Many existing programs include sludge-lancing operation, foreign object search and retrieval (FOSAR), visual inspection of components in the steam drum section, and visual/eddy current analysis for degradation in the tubes or tube support plates. Licensee responses suggest that most

undertake eddy current examinations to detect tube degradation and TSP degradation (if applicable), and also visual/video inspections of the tube bundles, the tubesheet, TSPs, and the U-bend region. Licensees follow EPRI's guidelines for maintaining both primary and secondary water chemistry.

- All licensees perform ASME Section XI Inservice Inspection (ISI) of welds every 5-10 years (mostly every 10-year schedule) following the NRC's ISI requirements.

- All licensees endorse the evaluation and recommendations made by their SG owners group about the EdF causal factors identified in EPRI GC-109558. Based on the owners groups' assessments, U.S. plants are not believed to be susceptible to the causal factors experienced at EdF units.

- Essentially all licensees reported no significant degradation in their SG internals caused by the mechanisms found in San Onofre. Many noted the potential susceptibility to flow-accelerated corrosion (FAC) in carbon steel tube supports with heavily fouled tube bundles. Significant repairs to date of SG secondary side components, either voluntary or required, have not been made.

- After reviewing the inspection records, each plant concluded that they comply with the current licensing bases, and no immediate changes to the current inspection programs are necessary.

All plants indicated that some program (formal or informal) for monitoring degradation of SG internals is in place and that inspections are typically carried out at each refueling outage (although not usually for all SGs at each refueling outage). Several plants with a history of problems similar to that described in the GL had already performed, or had plans to perform, comprehensive inspection of their SG internals during the next scheduled refueling outage. Further, several plants had replaced their SGs with new, improved designs. These improved designs included the use of corrosion-resistant materials, and better monitoring techniques which had significantly contributed to industry-wide enhanced management programs for SG internal components.

Westinghouse (W) SGs involving models 44, 51, 51M, and D3 and Combustion Engineering (CE) SGs with carbon steel eggcrate tube supports appear to be the most susceptible to the types of degradation identified in the GL. The replacement recirculating SGs by Babcock & Wilcox (B&W) are susceptible to peripheral tubes coming into contact during operation and so may incur fretting wear from flow-induced vibration at the point of contact. Specific recommendations were made by the W owners group, the CE owners group, and the B&W owners group to address these potential concerns. Each licensee has either implemented or is planning, as appropriate for its SGs, the implementation of the recommendations suggested by its owners group and/or by the industry for an inspection program for the SG internal components to address the long-term effects.

6.2 Conclusions

No licensee has reported any significant degradation in their SG internals at this time. Corrective and preventive measures were taken to mitigate any significant problems associated with SG internals encountered in the past. No observed degradation has progressed, according to sequential inspection data.

The existing SG internals inspection programs are plant-specific and generally include the following:

(1) Eddy current examinations of tubes that detect TSP degradation or presence of loose parts.

(2) Visual/video inspections of tubesheets, TSPs, tube bundle, steam drum, feedwater nozzles including thermal liners, feedwater distribution components, waterbox, and moisture separators.

(3) ASME Section XI In-Service Inspection of welds.

(4) FOSAR activities.

(5) Sludge-lancing, water-slapping or -lancing, chemical or pressure pulse cleaning.

From the results presented in the licensees' submittals, there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the licensing basis.

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APPENDIX A
GL 97-06 - DEGRADATION OF STEAM GENERATOR INTERNALS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

December 30, 1997

NRC GENERIC LETTER 97-06: DEGRADATION OF STEAM GENERATOR INTERNALS

Addressees

All holders of operating licenses for pressurized-water reactors (PWRs), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) again alert addressees to the previously communicated findings of damage to steam generator internals, namely, tube support plates and tube bundle wrappers, at foreign PWR facilities; (2) alert addressees to recent findings of damage to steam generator tube support plates at a U.S. PWR facility; (3) emphasize to addressees the importance of performing comprehensive examinations of steam generator internals to ensure steam generator tube structural integrity is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50; and (4) require all addressees to submit information that will enable the NRC staff to verify whether addressees' steam generator internals comply with and conform to the current licensing bases for their respective facilities.

Background

The NRC issued Information Notice (IN) 96-09 and IN 96-09, Supplement 1 to alert addressees to findings of damage to steam generator internals at foreign PWR facilities.

Description of Circumstances

Foreign authorities have reported various steam generator tube support plate damage mechanisms. The affected steam generators are similar, but not identical, to Westinghouse Model 51 steam generators. As previously documented in IN 96-09 and IN 96-09, Supplement 1, one damage mechanism involved the wastage of the uppermost support plate caused by the misapplication of a chemical cleaning process. A second damage mechanism involved broken tube support plate ligaments at the uppermost, and sometimes at the next lower, tube support plates. The support plate ligaments broke near a radial seismic restraint and near an antirotation key; the damage apparently dates back to initial startup of the affected plants. According to foreign authorities, the ligaments may have broken because of excessive stress during the final thermal treatment of the monobloc steam generators, which in-turn was caused by inadequate clearance for differential thermal expansion between the support plates, wrapper, and seismic restraints.

As previously documented in IN 96-09, Supplement 1, a third damage mechanism involved wastage not associated with chemical cleaning and affected tube support plates at various elevations. This damage mechanism is active (progressive) and apparently involves a corrosion or erosion-corrosion mechanism of undetermined origin.

The staffs of potentially affected foreign reactors are currently inspecting steam generators for evidence of the various damage mechanisms, both visually and with eddy-current testing. Tubes without adequate lateral support are being plugged.

IN 96-09, Supplement 1, also documented that cooling transients involving the injection of large quantities of auxiliary feedwater may have been a key factor in the steam generator wrapper drop phenomenon observed at a foreign PWR facility. These cooling transients are believed to have been particularly severe for two units as a result of the use of a special operating procedure to accelerate the transition from hot to cold shutdown. The weight of the wrapper assembly and support plates is borne by six tenons mounted on the steam generator shell. The wrapper is nominally free to expand axially relative to the shell. However, it is postulated that an interference fit developed between the wrapper and the seismic restraints (mounted to the shell) as a result of differential thermal expansion associated with the cooling transients at the seventh support plate elevation. This interference fit prevented axial expansion of the wrapper, which led to excessive vertical bearing loads at the tenon supports, thus causing localized wrapper failure at this location and downward displacement of the wrapper (20 millimeters maximum). Poor quality wrapper support welds may also have contributed to this failure. Repairs have been made at the affected foreign PWR facility. Wrapper dropping is being monitored in all steam generators of similar design. The monitoring is performed through both online instrumentation and visual inspections during outages. In addition to the wrapper dropping problem, cracking of the wrapper above the original upper support was discovered at the same foreign unit. The cause of the cracking is not yet known.

At a U.S. PWR facility, degradation of steam generator tube eggcrate supports was discovered through secondary side visual inspections performed during the spring 1997 refueling outage. The licensee identified erosion corrosion as the damage mechanism; the cause is not yet known. The damage appears to be confined to the periphery and the untubed staywell region of the tube bundle. The eggcrate degradation at the periphery extends inward to the first one or two rows of tubes. The degradation at the staywell region primarily affects the support structures within the untubed section. Damage to the eggcrate supports was found in both steam generators on the hot and cold leg sides although the damage was more extensive on the hot leg side. No degradation of eggcrate supports was identified within the tube bundle.

Discussion

The reported foreign and U.S. experience highlights the potential for degradation mechanisms that may lead to tube support plate and tube bundle wrapper damage. The steam generator tube support plates support the tubes against lateral displacement and vibration and minimize bending moments in the tubes in the event of an accident. Support plate damage can impair the support plate's ability to perform this function and, thus, could potentially lead to the impairment of tube integrity. Vibration-induced fatigue could present a potential problem if tube support plates lose integrity, particularly in areas of high secondary side cross flows. As previously noted in IN 96-09, tube support plate signal anomalies found during eddy-current testing of the steam generator tubes may be indicative of support plate damage or ligament cracking. Certain visual and video camera inspections on the secondary side of a steam generator may also provide useful information concerning the degradation of steam generator internals. The NRC staff will continue to monitor information on tube support plate and tube bundle wrapper damage as it becomes available.

This letter also alerts addressees to the importance of performing comprehensive examinations of steam generator internals to ensure steam generator tube structural integrity is maintained in accordance with the requirements of Appendix B to 10 CFR Part 50. More specifically, Criterion XVI of Appendix B, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected.

Required Information

Within 90 days of the date of this generic letter, each addressee is required to provide a written report that includes the following information for its facility:

(1) Discussion of any program in place to detect degradation of steam generator internals and a description of the inspection plans, including the inspection scope, frequency, methods, and equipment.

The discussion should include the following information:

(a) Whether inspection records at the facility have been reviewed for indications of tube support plate signal anomalies from eddy-current testing of the steam generator tubes that may be indicative of support plate damage or ligament cracking. If the addressee has performed such a review, include a discussion of the findings.

(b) Whether visual or video camera inspections on the secondary side of the steam generators have been performed at the facility to gain information on the condition of steam generator internals (e.g., support plates, tube bundle wrappers, or other components). If the addressee has performed such inspections, include a discussion of the findings.

(c) Whether degradation of steam generator internals has been detected at the facility, and how the degradation was assessed and dispositioned.

(2) If the addressee currently has no program in place to detect degradation of steam generator internals, include a discussion and justification of the plans and schedule for establishing such a program, or why no program is needed. Addressees are encouraged to work closely with industry groups on the coordination of inspections, evaluations, and repair options for all types of steam generator degradation that may be found.

The NRC is aware that the industry has developed generic guidance on performing steam generator inspections, and that this guidance is continually being updated. If an addressee intends to follow the guidance developed by the industry for this issue, reference to the relevant generic guidance documents is acceptable, and encouraged, as part of the response, as long as the referenced documents have been officially submitted to the NRC. However, additional plant-specific information will be needed.

NRC staff will review the responses to this generic letter and if concerns are identified, affected addressees will be notified.

Address the required written responses to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, under oath or affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f).

Backfit Discussion

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this generic letter transmits an information request for the purpose of verifying compliance with applicable existing regulatory requirements. Specifically, the requested information will enable the NRC staff to determine whether the condition of the addressees' steam generator internals comply with and conform to the current licensing bases for their respective facilities. In particular, the information would help the staff to ascertain whether the regulatory requirements pursuant to Appendix B to 10 CFR Part 50 are met.

No backfit is either intended or approved in the context of issuance of this generic letter. Therefore, the staff has not performed a backfit analysis.

Federal Register Notification

A notice of opportunity for public comment was published in the *Federal Register* on December 31, 1996 (61 FR 69116).

Paperwork Reduction Act Statement

This generic letter contains information collections that are subject to the Paperwork Reduction Act of 1995 (22 U.S.C. 3501 et seq.). These information collections were approved by the Office of Management and Budget, approval number 3150-0011, which expires on September 30, 2000.

The public reporting burden for this collection of information is estimated to average 80 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. The U.S. Nuclear Regulatory Commission is seeking public comment on the potential impact of the collection of information contained in the generic letter and on the following issues:

(1) Is the proposed collection of information necessary for the proper performance of the functions of the NRC, including whether the information will have practical utility?

(2) Is the estimate of burden accurate?

(3) Is there a way to enhance the quality, utility, and clarity of the information to be collected?

(4) How can the burden of the collection of information be minimized, including the use of automated collection techniques?

Send comments on any aspect of this collection of information, including suggestions for reducing this burden, to the Information and Records Management Branch, T-6F33, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0011), Office of Management and Budget, Washington, DC 20503.

The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

If you have any questions about this matter, please contact the technical contact listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

signed by D.B. Matthews for

Jack W. Roe, Acting Director
Division of Reactor Program Management
Office of Nuclear Reactor Regulation

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APPENDIX B
LICENSEES RESPONDED TO GL 97-06

No.	Licensee	Plant - Reactor Unit	# SGs	Remarks
PLANTS WITH B&W ONCE-THROUGH STEAM GENERATORS (OTSGs)				
1	Entergy	Arkansas Nuclear One - 1	2	
2	Florida Power & Light	Crystal River - 3	2	
3	Toledo Edison	Davis Besse - 1	2	
4	Duke Power	Oconee - 1	2	Planned replacement of B&W OTSG with B&W RSG - Fall 2003
5	Duke Power	Oconee - 2	2	Planned replacement of B&W OTSG with B&W RSG - Spring 2004
6	Duke Power	Oconee - 3	2	Planned replacement of B&W OTSG with B&W RSG - Fall 2004
7	GPU Nuclear	Three Mile Island - 1	2	
PLANTS WITH B&W REPLACEMENT STEAM GENERATORS (RSGs)				
1	Commonwealth Edison	Byron - 1	4	Replaced W D4 with B&W RSG - 2/98
2	Duke Power	Catawba - 1	4	Replaced W D3 with B&W RSG - 10/96
3	Rochester Gas & Electric	Ginna	2	Replaced W 44 with B&W RSG - 6/96
4	Duke Power	McGuire - 1	4	Replaced W D2 with B&W RSG - 5/97
5	Duke Power	McGuire - 2	4	Replaced W D3 with B&W RSG - 12/97
6	Northeast Nuclear	Millstone - 2	2	Replaced CE 67 with B&W RSG - 1/93
7	Florida Power & Light	St. Lucie - 1	2	Replaced CE 67 with B&W RSG - 1/98
NOTE: Braidwood - 1 and Cook -1 replaced W D4 (11/98) and W 51 (12/00), respectively.				
PLANTS WITH CE STEAM GENERATORS				
1	Entergy	Arkansas Nuclear One - 2	2	Replaced CE 2815 with W D109 - 12/00

APPENDIX B: LICENSEES RESPONDED TO GL 97-06

No.	Licensee	Plant - Reactor Unit	# SGs	Remarks
2	Baltimore Gas & Electric	Calvert Cliffs - 1	2	Planned replacement of CE 67 with B&W RSG - Spring 2002
3	Baltimore Gas & Electric	Calvert Cliffs - 2	2	Planned replacement of CE 67 with B&W RSG - Spring 2003
4	Omaha Public Power District	Fort Calhoun	2	
5	Consumers Energy	Palisades	2	Replaced CE with CE - 3/91
6	Arizona Public Service	Palo Verde - 1	2	
7	Arizona Public Service	Palo Verde - 2	2	Planned replacement CE 80 with ABB/Ansaldo - Fall 2003
8	Arizona Public Service	Palo Verde - 3	2	
9	Florida Power & Light	St. Lucie - 2	2	
10	Southern California Edison	San Onofre - 2	2	
11	Southern California Edison	San Onofre - 3	2	
12	Entergy	Waterford - 3	2	
PLANTS WITH W 51 SERIES STEAM GENERATORS				
1	Duquesne Light	Beaver Valley - 1	3	Planned replacement of W 51- 2007
2	Duquesne Light	Beaver Valley - 2	3	
3	Indiana Michigan Power	Cook - 1	4	Replaced W 51 with B&W RSG - 12/00
4	Indiana Michigan Power	Cook - 2	4	Replaced W 51 with W 54F - 1989
5	Pacific Gas & Electric	Diablo Canyon - 1	4	
6	Pacific Gas & Electric	Diablo Canyon - 2	4	
7	Southern Company	Farley - 1	3	Replaced W 51 with W 54F - 5/00
8	Southern Company	Farley - 2	3	Replaced W 51 with W 54F - 5/01
9	Wisconsin Public Service Corp.	Kewaunee	2	Planned replacement of W 51 with W 54F - Fall 2001

No.	Licensee	Plant - Reactor Unit	# SGs	Remarks
10	Virginia Electric & Power	North Anna - 1	3	Replaced W 51 with W 54F - 1993
11	Virginia Electric & Power	North Anna - 2	3	Replaced W 51 with W 54F - 1995
12	Wisconsin Electric Power	Point Beach - 2	2	Replaced W 44 with W Δ47- 1996
13	Northern States Power	Prairie Island - 1	2	Planned replacement of W 51- 2004
14	Northern States Power	Prairie Island - 2	2	
15	Public Service Electric & Gas	Salem - 1	4	Replaced W 51 with W F - 7/97
16	Tennessee Valley Authority	Sequoyah - 1	4	Planned replacement of W 51 with unknown SG - Spring 2003
17	Tennessee Valley Authority	Sequoyah - 2	4	
18	South Carolina Electric & Gas	Summer - 1	3	Replaced W D3 with W Δ75 - 1994
19	Virginia Electric & Power	Surry - 1	3	Replaced W 51 with W 51F - 1980
20	Virginia Electric & Power	Surry - 2	3	Replaced W 51 with W 51F - 1979
PLANTS WITH W 44, 44F, F, D-SERIES, AND E-SERIES STEAM GENERATORS				
1	Commonwealth Edison	Byron - 2	4	
2	Commonwealth Edison	Braidwood - 1	4	Replaced W D4 with B&W RSGs - 11/98
3	Commonwealth Edison	Braidwood - 2	4	
4	Union Electric	Callaway	4	Planned replacement of W F with unknown SGs - 10/2005
5	Duke Power	Catawba - 2	4	
6	Texas Utilities Electric	Comanche Peak - 1	4	
7	Texas Utilities Electric	Comanche Peak - 2	4	
8	Carolina Power & Light	Shearon Harris	3	Planned replacement of W D4 with W Δ75 - 9/01

APPENDIX B: LICENSEES RESPONDED TO GL 97-06

No.	Licensee	Plant - Reactor Unit	# SGs	Remarks
9	Consolidated Edison of New York	Indian Point 2	4	Not evaluated for EdF causal factors. Replaced W 44 with W 44F - 12/00
10	New York Power Authority	Indian Point - 3	4	Replaced W 44 with W 44F - 1989
11	Northeast Nuclear	Millstone - 3	4	
12	Wisconsin Electric Power	Point Beach - 1	2	Replaced W 44 with W 44F - 1983
13	Carolina Power & Light	Robinson - 2	3	Replaced W 44 with W 44F - 1984
14	Public Service Electric & Gas	Salem - 1	4	
15	North Atlantic Energy Service Corp.	Seabrook	4	
16	South Texas Project Nuclear Operating	South Texas Project - 1	4	Replaced W E with W D94 - 5/00
17	South Texas Project Nuclear Operating	South Texas Project - 2	4	Planned replacement W E with B&W RSG - Fall 2002
18	Florida Power & Light	Turkey Point - 3	3	Replaced W 44 with W 44F - 1981
19	Florida Power & Light	Turkey Point - 4	3	Replaced W 44 with W 44F - 1982
20	Southern Nuclear Operating	Vogtle - 1	4	
21	Southern Nuclear Operating	Vogtle - 2	4	
22	Tennessee Valley Authority	Watts Bar - 1	4	
23	Wolf Creek Nuclear Operating Corp.	Wolf Creek	4	

NOTES:
(1) The licensee names are in accordance with the GL responses at the time of this review.
(2) Plants are categorized in accordance with their GL submittals.

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Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

E. J. Sullivan, NRC Project Manager

11. ABSTRACT *(200 words or less)*

This report presents the results of an assessment of the nuclear power industry's response to NRC Generic Letter (GL) 97-06 on the degradation of steam generator internals experienced in EdF plants in France and in a U.S. pressurized water reactor (PWR). Before issuing the GL, with the exception of a few licensees, there were no formal inspection programs, nor any industry guidelines for monitoring the secondary side internals of steam generators. Nonetheless, all licensees have been performing some inspection and maintenance on their steam generator internals and have found no significant degradation in them. Most of the steam generators in the U.S. plants do not appear susceptible to degradation found in EdF and in the U.S. PWR.

Licensees plan to implement their owners group recommendations to address the long-term effects of the potential degradation mechanisms associated with the SG internals. Overall, the licensees' submittals have met the intent of the GL and provide reasonable assurance that the SG internals comply with, and conform to, the current licensing basis.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

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DECEMBER 2001