Assessment of Condenser Leakage Problems

NP-1467
Technical Planning Study TPS 79-729

Final Report, August 1980

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EPRI PERSPECTIVE

PROJECT DESCRIPTION

This study is one of two sponsored by the Steam Generator Owners Group to provide a basis for a program to improve power plant condenser performance which, in turn, would improve steam generator performance. This study is an assessment of recent experience and literature to determine what research and development work is necessary to correct engineering aspects of condenser air and cooling-water leakage problems. This final report covers work done under TPS 79-729 and is the only report to be issued concerning that work. A similar report on the second study, EPRI Final Report NP-1468, covers work on the chemistry and corrosion aspects of condenser leakage.

PROJECT OBJECTIVE

Condenser leakage, air and cooling-water, has been the primary cause of denting and other forms of corrosion damage in steam generators. The objective of this technical planning study is to describe available technology and to provide specific recommendations for further work to correct the causes of power plant condenser cooling-water and air inleakage. This study focuses on the engineering aspects of that problem, including the effects of manufacturing methods and procurement practices, to the extent that either of these aspects contributes to the probability of leakage in condensers.

PROJECT RESULTS

The study recommends that additional work is needed on cathodic protection, double tubesheet performance, low-level chlorination effectiveness, steam-water erosion of tubing, evaluation of flow-induced vibration correlations, and development of standard leak-detection procedures. In addition, it provides definitive recommendations regarding equipment specifications (design features, supporting analyses and tests, auxiliary equipment, and accessibility) and plant operation and maintenance procedures for condensers. These recommendations are being included in guidelines for use by utilities.

This report is of direct interest to those involved in condenser research and development, design, and operation. It is of general interest to steam power plant owners and operators.

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ABSTRACT

This report presents the results of a technical planning study of condenser leakage problems which was performed for EPRI. The planning study utilized information gathered by an HEI questionnaire on condenser tube leakage and the results of an earlier EPRI sponsored Bechtel survey of condenser leakage experience in steam plants.

Problem areas discussed in the report include air leakage, locating cooling water leaks, tube ID inlet attack, fouling, steam side erosion, flow induced vibration, OD corrosion, and tube to tubesheet leakage.

Recommendations are made for EPRI sponsored research, equipment specification requirements, and plant operating or maintenance procedures to mitigate the condenser leakage problems currently being experienced. EPRI sponsored research is recommended in the areas of cathodic protection, low level chlorination effectiveness, flow induced vibration, locating leaks, double tubesheet performance, and steam/water erosion of tubes.

CONTENTS

SUMMARY

Ingress of circulating water and oxygen into the condensate and feedwater of PWR power plants has been identified as the major source of corrosion in steam generators.

Results of a technical planning study of the engineering aspects of this ingress can be summarized as follows:

1. Operating experience and engineering evaluations have developed a general consensus that a leak-tight condenser is essential to a satisfactory boiler-water chemistry.

2. Demineralizers do not provide a satisfactory long-term alternate to a "tight" condenser.

3. Recent experience and evaluations suggest that minimal air leakage into the condenser is also important with respect to satisfactory performance of the steam generator.

4. Double tubesheets should be utilized to minimize potential leakage of rolled joints.

5. Cathodic protection systems should be developed for application of titanium tubing when used with copper alloy tube sheets.

6. Flow-induced vibration correlations should be evaluated with respect to field experience.

7. Standardized leak detection procedures for both air and circulating water inleakage should be developed.

In general, the report shows that the technology for designing and operating "tight" condensers is available. Attaining improved performance will require actions by utilities, architect/engineers, and vendors.

I. Introduction

This report summarizes the results of a technical planning study of condenser leakage problems, which was performed for the Electric Power Research Institute (EPRI).

Section II of this report summarizes the objective and scope of this study.

Section III of this report provides an overall assessment of condenser leakage problems and summarizes our major recommendations.

Section IV of this report includes a detailed review of generic condenser leakage problems and our recommendations in each problem area. The recommendations are divided into the categories of EPRI sponsored research, equipment specification requirements, and plant operating or maintenance procedures.

Section V presents references cited in this report.

Section VI includes Appendices to this report. These appendices cover a summary of unit shutdowns or power reductions attributed to condensers as reported by nuclear power plants during a one year period as well as a summary of the results of a HEI survey on condenser performance.

II. Objective of Study

The background, objectives, and scope of the study reported herein as described in the work statement provided by EPRI are given below. It should be noted that this study involves the evaluation of information on condenser problems gathered from existing data sources, both government and industry. Follow up visits to plants or in-depth investigations were not a part of this investigation.

"1.1 Background

Steam generator problems caused by corrosion damage have significant cost and plant availability implications. Degradation of steam generator mateerials due to the presence of aggressive impurities have proceeded to the point in several cases that owner utilities may be required to replace steam generators. Estimated costs for such replacement are high. This technical planning study is the precursor to and should provide the direction for subprograms to "Improve Control of Condenser Cooling Water Leakage"; which has the potential of eliminating/limiting the ingress of impurities, such that new steam generators and those not yet irreparably damaged will not require replacement during the projected plant lifetime.

1.2 Objectives

The objective of this technical planning study is to provide specific recommendations for further work to correct the causes of power plant condensers cooling water and air in-leakage. This particular study will focus on the engineering aspects of that problem. Engineering aspects are to include the effects of manufacturing methods and practices and purchasing practices to the extent that either of these aspects contribute to the probability of leakage of power plant condensers.

1.3 Task Description

A. Scope

This task is a technical planning phase within the larger project, Improve Control of Condenser Cooling Water Leakage. Its scope is to provide an engineering evaluation including technical justification and rationale for decisions and actions which implement additional testing or research or utilize results of completed previously authorized tests and research.
This evaluation will summarize and list areas which require further attention and those that

do not. Similarly, it will summarize and list conflicting information existing in literature or present practice with regard to reasons that certain leaks occur."

III. Overall Assessment and Summary of Recommendations

A. Incentive for Leak Tight Condenser

Operating experience and engineering evaluations have developed a general consensus that a leak tight condenser is essential to a satisfactory boiler water chemistry. Demineralizers do not provide a satisfactory long term alternate to a tight condenser. More recent experience and evaluations suggest that minimal air leakage into the condenser is also important with respect to satisfactory performance of the boiler or steam generator.

B. Incidence and General Causes of Condenser Leakage

The primary sources of information on operating experience with steam surface condensers utilized in the evaluations summarized in this report are (1) the responses to the HEI questionnaire on condenser tube leakage, (2) the Bechtel survey of condenser leakage sponsored by EPRI, (3) the monthly summary of information on operating power reactors (NUREG 0020), and (4) Nuclear Power Experience. The overall results from these sources of information are discussed in the following paragraphs.

In December of 1978 the Heat Exchange Institute (HEI) distributed a questionnaire on Steam Surface Condenser Tube Leakage to Edison Electric Institute members. Units covered by the questionnaire are those with a heat transfer surface area in excess of 50,000 square feet and in operation during the last 10 years. Copies of answers to this questionnaire were provided to EPRI. The results of replies to this questionnaire are summarized in Appendix B and discussed in detail later in this report. Of the 527 tube bundles covered by replies which were received, only 26 had not experienced condenser tube leaks. Problem areas resulting in leaks reported by responses to the HEI questionnaire are summarized in Table III-1. It should be noted that since more than one problem area could be present in a single unit, the total number of problem areas exceed the number of units covered by the HEI survey.

Reference 14 is a report of a survey of steam plant surface condenser leakage sponsored by EPRI and conducted by Bechtel Corporation. This report, published in March 1977, presents the results of a mail survey covering 87 stations with 264 generating units, a field survey covering 30 stations with 76 generating units, and a literature search. In the field survey different materials and replacement bundles are treated as separate tube sets resulting in a total of 684 tube sets. Problem areas resulting in leaks reported by responses to the broader mail survey are summarized in Table III-2. Again, it should be noted that more than one cause may apply to some of the plant units.

NUREG 0020, Operating Units Status Report - Licensed Operating Reactors, provides monthly highlights and statistics for commercial operating nuclear power plants. Although the report is restricted to nuclear plants it does provide the only general compilation of shutdowns and power reductions attributed to condenser leakage problems. Appendix A is a compilation of all unit shutdowns or power reductions attributed to condensers for the period June 1978 through May 1979 as reported in NUREG 0020.

These results are summarized in Table III-3. During this one year period leaks were reported for 27 of 65 operating plants. In reviewing Table III-3 it should be noted only instances when power reductions or shutdowns attributed to condenser leaks are covered. Leak testing and tube plugging of condensers during shutdowns attributed to other causes are not covered. It should also be noted that as many as 34 load reductions to check for and/or plug condenser leaks were reported by one utility.

Reference 13, Nuclear Power Experience, summarizes operating experience for nuclear plants from documents in publicly available reports and correspondence. Reports from foreign as well as domestic nuclear power plants are monitored and summarized in Reference 13. A review of Reference 13 indicates that 71 of 96 nuclear power plants have reported instances of condenser tube leakage.

In summary, problems with condenser leakage persist. Only a small fraction (≈10%) of operating condensers have not experienced leakage problems.

C. Recommendations

The most significant problem areas with respect to condenser leakage are discussed in Section IV of this report along with specific recommendations for action to mitigate the problems being experienced. The major recommendations are summarized below.

1. EPRI Sponsored Development

The major recommendations for EPRI sponsored research or development efforts are tabulated below. The recommendations are discussed in detail in Section IV for each of the areas of concern reviewed.

a. Demonstration projects to evaluate the potential for cathodic protection for control of inlet tube corrosion and/or impingement attack should be set up. Demonstration projects should be set up both for plants with polluted cooling water and for plants with unpolluted cooling water. The evaluation should include impact of chlorine and/or ferrous sulphate addition on effectiveness of cathodic protection.

b. The ability of low level chlorination (within limits set by EPA) supplemented by on-line mechanical cleaning to control biological fouling in non-copper alloy condenser tube applications should be determined by tests at a number of different sites.

c. Currently available flow induced vibration correlations should be evaluated with respect to their applicability to condensers at several installations. Evaluations should include instances where flow induced vibration problems have been experienced and applications which have not experienced flow induced vibration problems.

d. Standard leak location procedures including equipment selection should be developed and published. Both cooling water leaks (tube and tube to tubesheet joint) and air leaks should be included.

e. A program should be established to monitor and report experience with condensers with double tubesheets with the purpose of verifying that double tubesheets can eliminate condensate contamination due to tube to tubesheet leaks.

f. An experimental program should be set up to characterize steam side erosion behavior of materials under the conditions of flow, moisture content and pressure typical of condenser applications.

2. Equipment Specificaion

Major recommendations for requirements which should be imposed for the procurement of new condensers are discussed in detail in Section IV of this report and are summarized below.

a. Condenser Design Features

- The specified condenser tube material should be chosen from materials which appear to be resistant to tube ID inlet attack, tube ID pitting, and ammonia corrosion attack. Based on current knowledge this limits tube material for salt water service to titanium or one of the proprietary alloys currently under evaluation in operating condensers (e.g. AL-6X). In addition, austenitic stainless steel tubes appear to meet the above criteria for fresh water service. If other tube materials are specified (e.g. 70-30 Cu-Ni) additional auxiliary equipment to minimize inlet end attack should be procured (See section below on auxiliary equipment).

- Space for installation of mechanical on line cleaning equipment (Amertap or MAN) should be provided.

- Longitudinal hotwell baffles, leak detection troughs at each tubesheet, and corresponding sample connections and pumps should be specified to facilitate identification of the general location of a cooling water leak.

- The condenser supports for the secondary shell, hotwell, etc. should be designed for loads imposed by filling the secondary shell with water. This capability will allow secondary side flooding during outages to check for tube or tube to tubesheet leaks or to maintain wet layup.

- The arrangement of the exhaust neck should be required to be such that tubes are protected from direct impingement by steam and/or moisture through the exhaust neck. In addition, impingement protection against failed turbine parts (shrouding, etc.) should be required to the extent practicable without adversely affecting the distribution of steam flow into the tube bundle.

- All inlet connections into the condenser should be required to be baffled, to preclude impingement erosion on the tubes including drains, recirculation connections, make-up water connections, hot-well heat steam inlet, and the turbine bypass connection. Attachment welds for baffles and baffle supports should be required to be full penetration welds.

- A double tubesheet design should be specified to minimize the potential for tube to tubesheet leaks.

b. Supporting Analyses and Tests

The condenser supplier should be required to provide the calculations or test results to justify the design limits or features described below.

- Adequacy of tube support plate spacing and baffle arrangements with respect to flow induced vibration. As a minimum, adequacy with respect to the potential for fluid elastic vibration should be evaluated.

- Maximum power level for operation with one bundle isolated without encountering flow induced vibration problems in operating tube bundles.

- Structural adequacy with respect to differential pressure loading and vibration of flow distribution piping and baffling for tubine bypass or steam dump system and for condensate or feed by pass return lines considering the potential for high mass flow at high condenser vacuum.

- Hydraulic model test to assure that inlet waterbox configuration provides an acceptable flow distribution and velocities.
- Structural adequacy of tube to tubesheet joints. The analysis must demonstrate that tube loads are acceptably low for the method of attachment utilized.

c. Auxiliary Equipment

The recommended auxiliary equipment is summarized below.

- Mechanical on-line tube cleaning equipment (Amertap or MAN)
- Equipment needed for cathodic protection and ferrous sulfate injection for condenser applications where tube materials which have not proven resistant to tube ID inlet attack are specified.
- Chlorination equipment to control biological fouling of condenser tubes and of screen or retention devices on mechanical on line cleaning equipment.
- Bellows seals for valves in vacuum service.

d. Accessibility

The condenser design should be required to provide access for the following operations.

- Inspection and test for air in-leakage through the turbine exhaust expansion joints.

- Location of a cooling water leak including provisions for fast installation and removal of staging and work platforms inside the waterboxes.

- Inspection of all baffles of incoming water or steam connections (drains, steam dumps, make up water, etc.).

e. Procedures

- The supplier should be required to develop and qualify the tube to tubesheet joint forming process and equipment on a tubesheet mockup which is destructively examined.

- The supplier should be required to provide as-built drawings and a listing which describes the location, size, and type of all openings, connections, and fittings which are potential air inleakage sites.

- The supplier should be required to provide detailed inspection sheets which facilitate periodic inspection and verification that baffles are trouble free and that tubing is not experiencing impingement erosion.

3. Plant Operating or Maintenance Procedures

a. Maintenance Procedures

Procedures should be developed for the maintenance procedures tabulated below. The procedures should cover the equipment to be utilized as well as the sequence of operations to be performed.

- Detection and location of air leaks into the condenser.

- ECT inspection of condenser tubes.
- Location of cooling water leaks into the condenser through the tube or tube to tubesheet joints.
- Periodic manual cleaning of tube ID with scrapers or stiff brushes.
- Inspection of baffles and for any evidence of tube OD impingement attack.

b. Operating Procedures

Operating, startup, and layup procedures should include provisions which preclude seawater, brackish water, or polluted cooling water lying stagnant for any significant period of time in the condenser tubes or in the intake structure.

In addition, it would be prudent to operate with waterboxes high point continuously vented to preclude any accumulation of air bubbles in the waterbox.

TABLE 3-1

Overall Results of HEI Study

Conditions Resulting in Tube Leaks	Number of Units Affected (1)
No leakage reported	26
Tube to tubesheet leaks	109
Flow induced vibration	31
Thinning at tube supports	44
ID inlet erosion	78
Problems with OD erosion or baffles	77
Stress corrosion cracking	7
Air cooler section corrosion	59
Mechanical damage (e.g., turbine debris)	22
Erosion throughout ID (Sand, etc.)	37
ID corrosion or pin hole leaks	20
Defects in weld of welded tube	4
Galvanic corrosion between tubes and tubesheet or waterbox	1
Denickelification of 90-10 CuNi	3
Specific condition not reported	165

Note:(1) Survey covered 527 tube bundles

TABLE 3-2

Overall Results of Bechtel Mail Survey

Cause of Tube Failures	Bechtel Codes	Number of Units Affected (1)
No leakage reported	N	17
Joint Failures/Tube Rolling	J,R	4
Vibration	O	26
Erosion, impingement, cavitation (water and steam side)	E	59
Erosion, corrosion, air release (water side)	Z	19
Corrosion, chemical attack	C	30
Falling Objects, Missiles	F	15
Mechanical damage	M	20
Workmanship, erection	K	7
Poor cleaning, maintenance	Y	3
Objects lodged in tubes	L	3
Design	G	1
Thermal Stress, shock	T	7
Structural Failure	X	3
Waterhammer, hydrotest	H	3
Specific cause not reported	A,B,'D, U, V	96

Note: (1) Survey covered 264 units

TABLE 3-3

Nuclear Power Plant Condenser Statistics
June 1978 Through May 1979

UNIT	TOTAL CONDENSER OUTAGE FORCED + SCHEDULED (HOURS)	FORCED CONDENSER OUTAGE (HOURS)	NUMBER OF POWER REDUCTIONS DUE TO CONDENSER	NUMBER OF OUTAGES DUE TO CONDENSER	TOTAL PLANT FORCED OUTAGE (HOURS)	PLANT FORCED OUTAGE DUE TO FORCED CONDENSER OUTAGE (PERCENT)
Arkansas 1	0	0	0	0	1600.	0
Arkansas 2	68.9	68.9	0	1	1700.	4.05
Beaver Valley 1	4.9	4.9	0	1	6690.	0.07
Big Rock Point 1	0	0	0	0	3592.	0
Browns Ferry 1	0	0	0	0	732.	0
Browns Ferry 2	0	0	0	0	193.	0
Browns Ferry 3	11.6	11.6	0	2	564.	2.06
Brunswick 1	125.2	44.7	0	4	504.	8.87
Brunswick 2	437.5	14.5	0	3	1008.	1.44
Calvert Cliffs 1	0	0	0	0	820.	0
Calvert Cliffs 2	0	0	0	0	541.	0
Cook 1	602.6	12.4	0	2	292.	4.25
Cook 2	302.4	302.4	2	7	738.	40.98
Cooper Station	0	0	0	0	102.	0
Crystal River 3	0	0	2	0	3441.	0
Davis Besse 1	0	0	0	0	1760.	0
Dresden 1	0	0	0	0	229.	0

Nuclear Power Plant Condenser Statistics
June 1978 Through May 1979

UNIT	TOTAL CONDENSER OUTAGE FORCED + SCHEDULED (HOURS)	FORCED CONDENSER OUTAGE (HOURS)	NUMBER OF POWER REDUCTIONS DUE TO CONDENSER	NUMBER OF OUTAGES DUE TO CONDENSER	TOTAL PLANT FORCED OUTAGE (HOURS)	PLANT FORCED OUTAGE DUE TO FORCED CONDENSER OUTAGE (PERCENT)
Dresden 2	0	0	0	0	497.	0
Dresden 3	0	0	0	0	3358.	0
Duane Arnold	0	0	0	0	7063.	0
Farley 1	0	0	0	0	438.	0
Fitzpatrick	0	0	0	0	2080.	0
Fort Calhoun	0	0	1	0	329.	0
Ginna	0	0	0	0	50.	0
Haddam Neck	0	0	0	0	56.	0
Hatch 1	0	0	0	0	953.	0
Humboldt Bay	0	0	0	0	0.	0
Indian Point 2	20.6	20.6	0	1	469.	4.39
Indian Point 3	0	0	0	0	337.	0
Kawaunee	0	0	1	0	55.	0
Lacrosse	0	0	0	0	723.	0
Maine Yankee	774.13	440.33	0	34	2252.	19.55
Millstone 1	0	0	12	0	615.	0
Millstone 2	0	0	1	0	18.	0

Nuclear Power Plant Condenser Statistics
June 1978 Through May 1979

UNIT	TOTAL CONDENSER OUTAGE FORCED + SCHEDULED (HOURS)	FORCED CONDENSER OUTAGE (HOURS)	NUMBER OF POWER REDUCTIONS DUE TO CONDENSER	NUMBER OF OUTAGES DUE TO CONDENSER	TOTAL PLANT FORCED OUTAGE (HOURS)	PLANT FORCED OUTAGE DUE TO FORCED CONDENSER OUTAGE (PERCENT)
Monticello	0	0	0	0	334.	0
Nine Mile Point 1	0	0	0	0	159.	0
North Anna 1	0	0	0	0	1086.	0
Oconee 1	0	0	1	0	554.	0
Oconee 2	139.3	139.3	3	1	1341.	10.39
Oconee 3	0	0	0	0	575.	0
Oyster Creek	0	0	0	0	1438.	0
Palisades	0	0	0	0	1964.	0
Peach Bottom 2	0	0	0	0	211.	0
Peach Bottom 3	0	0	0	0	105.	0
Pilgrim	0	0	5	0	1081.	0
Point Beach 1	0	0	0	0	71.	0
Point Beach 2	8.0	0	0	1	0.	N/A
Prairie Island 1	0	0	2	0	175.	0
Prairie Island 2	0	0	0	0	53.	0
Quad Cities 1	0	0	10	0	131	0
Quad Cities 2	0	0	10	0	132.	0

Nuclear Power Plant Condenser Statistics
June 1978 Through May 1979

UNIT	TOTAL CONDENSER OUTAGE FORCED + SCHEDULED (HOURS)	FORCED CONDENSER OUTAGE (HOURS)	NUMBER OF POWER REDUCTIONS DUE TO CONDENSER	NUMBER OF OUTAGES DUE TO CONDENSER	TOTAL PLANT FORCED OUTAGE (HOURS)	PLANT FORCED OUTAGE DUE TO FORCED CONDENSER OUTAGE (PERCENT)
Rancho Seco	0	0	0	0	692.	0
Robinson 2	0	0	0	0	588.	0
Salem 1	141.6	141.6	8	2	1835.	7.72
San Onofre 1	13.3	6.8	2	2	110.	6.18
St. Lucie 1	16.2	0	0	1	400.	0
Surry 1	0	0	0	0	2544.	0
Surry 2	0	0	0	0	61.	0
Three Mile Island 1	0	0	0	0	2292.	0
Three Mile Island 2	0	0	1	0	2004.	0
Trojan	0	0	0	0	4818.	0
Turkey Point 3	24.1	24.1	10	1	513.	4.70
Turkey Point 4	68.7	0	3	2	95.	0
Vermont Yankee	0	0	0	0	1438	0
Yankee Rowe	0	0	0	0	233.	0
Zion 1	0	0	0	0	631.	0
Zion 2	0	0	0	0	50.	0
TOTAL	2759.03	1232.13	74	65	71513.	1.72

IV. Generic Problems and Recommended Courses of Action

A. Air Leakage

Severe air leakage into the condenser can result in an increase in turbine back pressure and adversely affect the plant efficiency. Air in-leakage into a BWR condenser can overload the gaseous radwaste (i.e., recombiner) system. At Indian Point 2, a PWR, lowering the air in-leakage has reduced corrosion products to the steam generators by 50% (Reference 43). Smaller amounts of air leakage can still be deleterious by serving as a source of oxygen and carbon dioxide. Carbon dioxide can lower the pH and accelerate attack on copper alloy tubes in the air cooler section. There are indications that copper oxides formed in the condenser may play a role in carbon steel corrosion in steam generators, even for plants which utilize hydrazine as an oxygen scavenger in the condensate.

1. Operating Experience

The amount of air in-leakage being encountered in operating plants was not covered by the Bechtel survey performed for EPRI or by the HEI survey of tube end leakage. There are reports in Nuclear Power Experience of problems with excessive air leakage or inadequately designed air removal drain lines for condensers at Nine Mile Point, Dresden 3, Peach Bottom 2 and 3, and Oyster Creek. These are BWR's and the major concerns were effects on turbine back pressure and the condenser off-gas treatment system.

2. Evaluation and Discussion

The amount of air leakage into a condenser can be measured by measuring the flow at the air ejector exit after the motive steam, if steam jet air ejectors are used, is condensed. The flow may vary from below 10 scfm to over 30 scfm depending on the degree of leak tightness of the plant. Reference 41 describes the approach used to locate a leak of 410 scfm in the Dresden 3 condensers. There are hundreds of potential leak paths through which air might enter the vacuum side of the condenser. Valves in lines attached to the condenser may develop packing leaks. Joints around inspection plates or rupture discs may leak. Expansion joints may also leak. The most successful leak location techniques utilize a freon or helium tracer gas and a detector at the air ejector outlet for condensers in fossil or PWR plants and in the off-gas line for BWR plants. Since the number of potential leak sites is so large a check list is required to facilitate a systematic check of each potential leak site.

Japanese experience with condensers, including Reference 42, indicate a close attention to preventing air inleakage to condensers including bellows seals on valves in lines connected to the condenser and use of de-aerated demineralized water for make-up feed. The resulting control of oxygen and the low level of circulating water in-leakage have resulted in the situation where denting has not been reported in steam generators for Japanese PWR plants.

3. Recommendations

a. EPRI Sponsored Support

It is recommended that EPRI, working with a cooperating utility, publish an air leak location procedure including equipment selection and the results obtained by use of the procedure in a typical power plant.

b. Equipment Specification Requirements

Consideration should be given to bellows sealed valves in vacuum service.

The condenser specification should require access to inspect and test for air in-leakage through the turbine exhaust expansion joints.

The condenser specification should require the condenser supplier to supply the Purchaser as-built drawings and listing which describe the location, size, and type of all openings, connections and fittings which are potential air in-leakage sites during condenser operation.

c. Operating or Maintenance Procedures

A procedure should be developed for detection of air leaks into the condenser. The procedure should include the equipment to be used and a listing of each potential leak path and should provide spaces to document checks made and record the results.

B. Leak Detection and Location

Leaks may be detected either by a buildup of non-volatile contaminants in the boiler or steam generator or by an increase in the conductivity or chloride or sodium ion concentration of samples taken from the condenser hotwell region or from the condensate or feed systems. In most cases the detection of leaks is simpler than determining the location of the specific leaking tube. In some cases the utility may detect a small leak which is still large enough to adversely effect water chemistry and shut down only to be unable to locate the leak.

1. Operating Experience

The Bechtel survey of condenser operating experience sponsored by EPRI and reported in Reference 14 indicates the following with regard to the sensitivity of leak location methods in use at the time of the survey.

- The operators of 10 condenser tubesets reported that leaks as small as 0.003 gpm could be located using a combination of plastic film and hydrostatic test with dye.
- The operators of 50 condenser tubesets reported that leaks as small as 0.01 gpm could be located using a combination of foam or soap, hydrostatic test without dye, waterbox flooding without gas, and eddy current testing.

Subsequent work reported in the January/February 1979 EPRI Journal resulted in the development of a tracer-gas method of locating leaks in condenser tubes. The tracer-gas can be helium or freon. Basically the tracer-gas is released in the vicinity of a suspected tube leak while the condenser shell side is under vacuum. A detector is placed at the air ejectors. Detection of the tracer-gas indicates a leak at the location of the tracer-gas release. A condenser leak estimated by Florida Power and Light to be on the order of 0.0007 gpm was located by using the helium leak detection procedure developed by Science Applications, Inc. (SAI) under an EPRI contract. At Turkey Point trials using both freon and helium resulted in the location of a leak of 0.0003 gpm. (Reference 43)

2. Evaluation and Discussion

Leak Location

The results achieved by SAI and Florida Power and Light with the tracer gas leak location technique are encouraging. However, further trial use of the tracer gas technique to locate leaks at a number of sites will be required before the limitations and critical parameters of the procedure are fully defined. Hydrostatic testing with dye appears to be a fairly sensitive leak technique. This procedure involves filling the secondary side with water. This technique can be used only if the condenser supports are structurally adequate to support the secondary side filled with water.

Condenser Design Features to Faciliate Leak Location

Tube leak dection troughs at each tubesheet and a sub-divided hotwell are design features which can facilitate determining the general area in the tube bundle of a leak.

The ability to determine which particular tube bundle is leaking, to drain the waterbox for that bundle, and to locate and plug the condenser leak while operating at part power minimizes the impact of condenser leaks on availability. The ability to sample individual hotwell compartments is desirable in that dilution of a leak is minimized and the leak is easier to detect.

With respect to isolation of the cooling water side of a tube bundle while operating at part power, it should be recognized that the potential for flow induced vibration in the operating bundles is increased. The adequacy of the tube bundle supports with respect to flow induced vibration should be checked by analysis or test for the condition of an isolated bundle and power limits chosen for this condition selected so that flow induced vibration will not be a problem.

Waterboxes of condensers are quite large. Design details for staging or platform supports which can be installed and removed relatively quickly can significantly reduce the time at shutdown or reduced load.

Non-destructive Testing

The EPRI sponsored Bechtel survey of condenser performance indicates that eddy current inspection is used on about 30% of the tubesets covered by the survey. There is a wide variance in the sensitivity of eddy current inspection equipment ranging from single coil probalog equipment to the differential coil probes similar to those used in steam generator tube inspections. During plant outages there is a great incentive to obtain an early indication of condenser tube corrosion attack by performing an ECT inspection. The interpretation of the results can be facilitated if the results of a baseline ECT inspection are available.

3. Recommendations

a. EPRI Sponsored Research

Follow up work to utilize the tracer gas leak location procedure and equipment under a number of conditions and at a number of sites to further refine the procedure appears to be warranted. Each application should be documented. The objective of this work is the preparation of a formal procedure and equipment specification in sufficient detail that individual utilities can utilize the technique with their own personnel.

b. <u>Equipment Specification Requirements</u>

Condenser equipment specifications should specify longitudinal baffles in the hotwell, leak detection troughs at each tubesheet, and corresponding sample connections and pumps. The purpose of the longitudinal baffles is to aid in determining in which bundle a leak is located. Leak detection troughs at each tubesheet provide an indication of whether tube to tubesheet leaks are being encountered.

Condenser equipment specifications should require the condenser supplier to submit for approval the design features to be provided to facilitate leak location both for shutdown and operation at reduced power. These design features should include provisions for fast installation and removal of staging and work platforms within the waterbox. Requirements for ventilation flow and provisions for this flow in the waterbox design should be described by the supplier. The maximum temperature inside the waterbox while operating at part power and with the specified ventilation flow should be calculated by the supplier.

The condenser equipment specification should require the condenser supplier to calculate the maximum power level for operation with one bundle isolated with respect to flow induced vibration.

The condenser equipment specification should require the condenser to be designed to have the capability for secondary side flooding during outages to permit location of any tube or tube to tubesheet leakage or to provide wet lay-up. The condenser supports, shell, hotwell, etc., should be designed for loads imposed by a secondary shell filled with water.

c. Operating or Maintenance Procedures

ECT equipment and procedures similar to those in use for PWR steam generators should be developed. The equipment and procedures should be used to perform a baseline ECT field test of all tubes. The report of this baseline inspection should include copies of the procedures, calibration data, and a complete set of the test data on magnetic tapes.

C. Tube ID Inlet End Attack

1. Operating Experience

Inlet tube corrosion and/or impingement attack is a major problem in surface condensers, particularly for condensers cooled by brackish water or sea water. The attack occurs within the first ten inches of the tube and the metal surface may take on the appearance of gouges or ripples with a horseshoe shaped cavity or pit with the toe pointing in the upstream direction. Information summarized in Nuclear Power Experience indicates inlet end attack played a role in condenser problems experienced at Millstone 1, Pilgrim, Oyster Creek, San Onofre, and Robinson 2.

The EPRI sponsored survey of operating experience with steam plant surface condensers confirms that erosion/corrosion attack is a significant problem in U.S. condensers. Table IV.C-1 summarizes the reports of tube sets from the field survey reporting erosion, corrosion, air release or cavitation (See Note 1 in Table IV.C-1) as a contributor to condenser leakage.

As indicated in Table IV.C-2 most of the incidences of erosion, corrosion, air release, or cavitation occurred in brackish water or sea water.

The data also appears to indicate that the use of ferrous sulfate can reduce the incidence of "erosion/corrosion,

TABLE 4.C-1

Bechtel Data Summary

Tube Material	Tube Sets Covered By Study	Tube Sets for Which Erosion/ Corrosion, Air Release, Cavitation is Reported as a Cause of Leakage	Fraction
Not described	62	13	.21
Aluminum Bronze	16	9	.56
Admiralty	153	11	.07
Aluminum Brass	57	29	.51
90-10 Cu Ni	99	24	.24
70-30 Cu Ni	79	31	.39
304 SS	147	0	.00
316 SS	34	8 (2)	.24 (2)
Titanium	33	0	.00

TABLE 4.C-2

Summary of Cooling Water Where Inlet Attack Occurred

	SEAWATER					FRESH WATER				
TUBE MATERIAL	Brackish	Polluted Brackish	Clean Sea Water	Polluted Sea Water		Lake	Spring Pond Canal	River	Tower	Total
Al-Bronze	9									9
Admiralty						3		4	4	11
Al-Brass		7	6	16						29
90-10 Cu-Ni	12	4	4						4	24
70-30 Cu-Ni	1	4	9	13			4			31
316 Stainless		8(2)								(2) 8
Not Specified	1	2	2	4		2			2	13
Totals	23	25	21	33		5	4	4	10	125

Note: (1) The Bechtel field survey results do not identify whether "erosion/corrosion, air release, cavitation" is on the steam side or water side.

(2) It should be noted that the Bechtel mail survey recorded no instances of water side "erosion/ corrosion, air release, cavitation" in 304 or 316 stainless steel. Further clarification is required to determine if reported results indicate that 316 stainless steel experiences inlet ID attack.

air release, or cavitation" in copper alloys. Specifically, the following information should be noted.

- Each instance of tube erosion/corrosion in aluminum bronze occurred in brackish chlorinated water. Each tube set not reporting attack operated in polluted brackish water but was treated with a combination of chlorine and ferrous sulfate.

- No tube set of Admiralty operated in brackish water or seawater. Only one tube set operated in polluted brackish water. Thus the relatively low incidence of tube ID attack in Admiralty tubes may be misleading.

- There are six cases where aluminum brass operated in polluted brackish water which was treated with a combination of chlorine and ferrous sulfate. No ID inlet attack was reported for these six cases. The Bechtel survey results indicate that all aluminum brass tube sets cooled by seawater experienced tube ID attack. Only chlorine was added for these cases, not ferrous sulfate. It is possible that low levels of ammonia or sulfur compounds were present in the seawater.

- There are thirty-three cases where 90-10 Cu-Ni tubes operated in brackish or polluted brackish water which was treated with a combination of chlorine and ferrous sulfate. In only four of these cases was "erosion/corrosion, air release or cavitation" listed as a contributor to tube leakage.

- There are twenty-three cases where 70-30 Cu-Ni operated in brackish or polluted brackish water which was treated with a combination of chlorine and ferrous sulfate. In only four of these cases was "erosion/corrosion, air release or cavitation" listed as a contributor to tube leakage.

- There are no instances of "erosion/corrosion, air release or cavitation" in 304 stainless tubes or titanium tubes.

- There are sixteen instances where 316 stainless steel tube sets operated in polluted brackish water. In eight of these instances "erosion/corrosion, air release or cavitation" was listed as a contributor to tube leakage. However, as previously noted further checking is required to remove uncertainties over whether or not "erosion/corrosion, air release or cavitation" was on the OD or ID of the 316 stainless steel tubes.

The results of the HEI survey are summarized below. These results are relatively consistent with the results of the Bechtel survey but do suggest a somewhat more marginal performance for 90-10 and 70-30 Cu-Ni.

HEI DATA SUMMARY

Tube Material	Tube Sets Covered By Survey	Tube Sets for Which ID Inlet Attack Was Indicated	Fraction
Arsenical Copper	38	3	.08
Al-Bronze or Brass	57	24	.42
Admiralty	255	23	.09
90-10 Cu-Ni	50	16	.32
70-30 Cu-Ni	16	12	.75
Stainless Steel	87	0	.00
Titanium	12	0	.00

Reference 11 reports the results of an INCO/Brass Mill condenser tube performance study on six tube end insert samples of each alloy (Admiralty, Aluminum-Brass, and various 70-30 and 90-10 Cu-Ni alloys) in each of seventeen coastal condensers. The results indicate that of the copper alloys 70-30 Cu-Ni and a 70-30 Cu-Ni with added Fe and Mn were the most resistant to inlet end attack in clean seawater and in the polluted seawaters encountered at the seventeen different installations over the 5.1 to 6.9 year period of the study.

The conclusion that 70-30 Cu-Ni is more resistant to inlet end attack than 90-10 Cu-Ni appears to be contrary to the results of the Bechtel and HEI surveys. It should be noted that results reported in Reference 4 indicate that the corrosion resistance of 90-10 Cu-Ni relative to that of 70-30 Cu-Ni is affected by the duration and sequence of exposure to low level sulfides. Conclusions on whether 70-30 Cu-Ni or 90-10 Cu-Ni is more resistant to inlet and attack for one sequence of exposures to low level sulfides do not appear to be applicable to a different sequence of exposures.

Reference 11 also summarizes experience described by Sato with aluminum-brass tubes in Japan. This experience indicates that in 1965 failure rates due to "malignant impingement attack" were on the order of ten failures per 10,000 tubes per year. By 1968 failure rates due to "malignant impingement attack" were less than one failure per 10,000 tubes per year and they have remained low. This improvement was obtained through use of ferrous sulfate, tube end protective inserts and cathodic protection.

2. Evaluation and Discussion

Engineering evaluations and operating experience described in the literature indicate that there are several factors which can affect the incidence of inlet tube corrosion and/or impingement attack. These factors are listed below and discussed in the following paragraphs.

- Tube material selection
- Velocity distribution at inlet tubesheet
- Coatings or inserts to protect the tube ends
- Cathodic protection
- Influence of sulfides and layup procedures
- Treatment of cooling water with ferrous sulfate

Tube Material Selection

Operating experience with titanium and austenitic stainless steel indicate that these materials are not subject to inlet tube corrosion and/or impingement attack for current condenser operating conditions. Very limited operating experience with the modified stainless steel, AL-6X, also indicates no problem with inlet end attack. For future condensers consideration should be given to use of titanium or stainless steel tubes depending on the cooling water which will be utilized by the condenser. However, it should be recognized that biological fouling will occur at a significantly higher rate with titanium or stainless steel tubes than with copper alloy tubes. This increased fouling tendency will probably dictate utilization of mechanical on-line cleaning and/or chlorination of the cooling water with condensers having non copper alloy tubes. See Section IV-D of this report. In particular stainless steels appear to be sensitive to pitting in brackish or seawater environments.

Velocity Distribution at Inlet Tubesheet

Reference 2 indicates that the presence of entrained air in seawater is one of the determining causes of the impingement corrosion phenomena and that the radial component of the water flow rate at the inlet of the tubes is one of the most critical factors. Reference 2 also indicates that it is important to avoid the coalescence of small air bubbles to larger, dangerous (turbulence producing) air bubbles by the configuration of intake structures and waterbox. Reference 54 also reports the results of jet impingement tests which indicate that the severity of impingement attack was considerably increased when air bubbles were present. However, the actual flow field at the tubesheet is difficult to determine by analysis.

Reference 9 describes the use of a 1:7.8 scale hydraulic model to determine flow patterns, velocity distributions, and turbulence intensities within the waterboxes of a two pass condenser. Measured velocities at the first pass intake tubesheet varied from less than 1 ft/sec to 4.8 ft/sec with a mean of 2.2 ft/sec.

A considerable variation in turbulence intensity was also measured. The model test indicated that a vortex tube was formed at the sudden expansion into the inlet waterbox. The observed range of velocities was greater than analysis of potential velocity differences would indicate. This result indicates that local velocities may be more than twice the average velocity and that the waterbox configuration can affect the potential for inlet tube attack. A prudent course of action would be to model new waterbox configurations to assure that the mal-distribution of velocity and turbulence intensity in the waterbox is minimized or within acceptable limits.

Reference 10 describes waterbox/tubesheet model testing and indicates that a model of about 1/10 to 1/15 scale can adequately represent the hydraulics of the full scale circulating water system.

Coatings or Inserts to Protect Tube Ends

In existing condensers one approach which has been used to control or minimize inlet tube ID attack has been the use of coatings or inserts to protect tube ends. Reference 8 describes the use of sprayed-in epoxy tube coatings and epoxy coatings applied to the tube while withdrawing a plunger/applicator.

Reference 12 and periodic operating reports to AEC summarize extensive experience at San Onofre with condenser tube inlet end attack and with the use of coatings and inserts to mitigate this attack. No entirely satisfactory method for protection of the 90-10 Cu-Ni tubes was found at San Onofre and the condensers were retubed with titanium. Replacement tubes were allowed to protrude about six inches into the inlet plenum from the tubesheet to mitigate the effects of eddying and attack within the first six inches of the tubes. Other reports indicate that tube end inserts may simply transfer the problem to the end of the insert. The use of plastic inserts may also complicate application of cathodic protection. In summary, tube end inserts or coatings alone do not appear to correct or prevent tube ID inlet attack.

Cathodic Protection

Reference 2 presents the morphology of "horse shoe" corrosion of copper alloys in sea water cooled condensers and discusses the mechanism of nucleation and of development of this type of corrosion. Reference 2 concludes that horse shoe corrosion is the result of an active-passive cell: the pH of the sea water is the determining factor, and the development of the corrosion is strongly influenced by the local hydrodynamic conditions. The results of the evaluation discussed in Reference 2 were used to define the requirements for a recommended cathodic protection of the condenser tubes. In summary, the article concludes that cathoic protection of tubes in condensers must be done at potential values between -0.175 and -0.48 V(NHE). It should be noted that this range of potential values is appropriate for unpolluted seawater but may not be appropriate for seawater polluted with sulfur compounds. Work reported in Reference 55 indicates that for seawater contaminated by sulfides cuprous sulfide is the stable copper species in the potential range between -0.2 and -0.6 V (SHE). Cuprous sulfide is much less likely to provide a protective film. The parameters to be used in application of cathodic protection to a condenser with sulfide contaminated cooling water should be chosen based on the parameters used in previous successful applications of cathodic protection (e.g. Japanese experience and experience reported in Reference 57) supplemented by lab or loop scale verification tests. For sea water, cathodic protection will require on the order of 2 mA per tube. This will require total currents on the order of 100A which will require the use of external current. Navy experience reported in Reference 56 with impressed current anode materials indicate that platinum clad tantalum provides excellent service at the lowest projected total cost.

Reference 3 reports that aluminum brass tubing is used successfully in Japan in non-treated sea water under the suitable application of cathodic protection to prevent inlet attack, special filters in the water intake pipe to prevent accumulation of debris (mussels) in the tube and use of sponge ball cleaning averaging a frequency of 10 balls per tube per week to clean the tubes periodically. Corrosion resistance of 90-10 Cu-Ni to inlet attack and local erosion is several times as good as aluminum brass. However, this alloy is reported by Reference 3 to suffer erosion/corrosion from sponge ball cleaning at an average frequency of 10 balls per tube per week.

Influence of Sulfides and Layup Procedures

Reference 11 indicates that during layup with the tubes and intake pipe full of stagnant sea water, oxygen is consumed by the marine organisms. As the oxygen is consumed the organisms die and the resultant decay generates hydrogen sulfide. Sulfide containing water can have an adverse effect on copper alloy tubes. Reference 1 indicates that in sea water polluted with sulfides, the threshold velocity for damage on 90-10 Cu-Ni can drop to 3-5 ft/sec which is far below the usual threshold of more than 10 ft/sec. Reference 11 recommends that the intake water system be flushed on start-up of the pumps until no pollutants can be detected before the water passes into the condenser. During wet layup of the cooling system circulation of fresh cooling water through the condenser for a short period each shift is also recommended.

Reference 7 reports the results of a laboratory study of several condenser tube alloys in flowing buffered sodium chloride solution, contaminated periodically with 10 ppm sulfide. The results showed that alternate treatment with sulfide and air was much more aggressive than either alone. The attack induced in the alloys tested is summarized below.

Material	Velocity ft/sec	Erosion	Pitting	Crevice Corrosion
90-10 Cu-Ni	4.6	Slight	Slight	
90-10 Cu-Ni	7.0		Slight	
70-30 Cu-Ni	4.6		Slight	
70-30 Cu-Ni	7.0	Heavy	Slight	
Admiralty	4.6	Heavy		
Admiralty	7.0	Heavy		
Al-Brass	4.6	Slight		
Al-Brass	7.0	Slight	Medium	
Modified Al-Brass	4.6	Medium	Medium	
Modified Al-Brass	7.0	Medium	Medium	
Aluminum-Bronze	7.0	Slight	Medium	
302 Stainless Steel	7.0		Heavy	
316 Stainless Steel	7.0			Heavy

Reference 7 concluded that the best alloys tested for the intermittent sulfide contamination were 90-10 Cu-Ni and the aluminum bronze.

A later study, Reference 4, reports the results of testing of 70-30 and 90-10 Cu-Ni alloys at lower sulfide concentrations (0.007 to 0.25 mg/L). The results indicate that both 90-10 and 70-30 Cu-Ni alloys are susceptible to sulfide induced localized attack in sea water at sulfide concentrations in the range of 0.007 mg/L or greater. In contrast to results at higher sulfide concentration, 70-30 Cu-Ni showed better resistance to severe attack when exposed to long term low concentration sulfides. The results also indicate that, when sulfide exposure conditions are sufficient to initiate attack, the effect of sea water velocity on the corrosion rate is minimal in the range of 1.6 to 17.4 ft/sec.

Treatment of Cooling Water with Ferrous Sulphate

Reference 6 reports that the corrosion of copper alloy tubes by contaminated cooling waters has sometimes been successfully controlled by the addition of small amounts of ferrous sulfate to the cooling water. Concentrations of 0.5 ppm to 2 ppm Fe^{++} have been used.

Reference 6 discusses the mechanism of protective film formation which results from the use of ferrous sulfate treatment of the cooling water and suggests exploration of the protection provided by a concentration range of ferrous sulfate below 0.5 ppm.

3. Recommendations

(a) EPRI Sponsored Research

As a prudent follow-up the data gathered in the Bechtel field survey should be examined to determine whether ID inlet attack has been reported for 316 stainless steel tubes. If so, follow-up visits to determine the circumstances associated with the attack may be appropriate.

A research effort to follow up on the potential for control of inlet tube corrosion and/or impingement attack by cathodic protection and use of ferrous ion treatment of the cooling water is recommended. Such an effort would involve selection of a cooperating utility with a condenser experiencing significant inlet end attack.

A cathodic protection system should be designed taking into account successful Japanese use of cathodic protection and the experience reported in Reference 57. In addition, laboratory or pilot scale tests may be required.

The method and amount of ferrous ion addition should be determined taking into account experience reported in Reference 57 and tests reported in Reference 58.

After a complete inspection of the condition of the tube ends the condenser should be thoroughly cleaned, the cathodic protection system should be installed and operated along with a ferrous ion addition regime. Periodic inspections of the tube end conditions should be carried out. An evaluation report of the effectiveness of this effort should be prepared.

(b) Equipment Specification Requirements

To minimize condenser tube inlet end attack in new condensers, the following requirements should be considered for incorporation in condenser equipment specifications.

- The inlet waterbox and tubesheet should be modeled by a tenth scale hydraulic model to assure that the configuration is such that an acceptable flow distribution and tube velocities will be obtained in the full scale unit. The results of the hydraulic model testing and review of the details of the circulation system including the circulating water pump head flow curve should be evaluated to assure that the maximum tube velocity will not exceed acceptable values for the tube material to be used.

- Tube materials should be chosen from materials which do not appear to experience tube inlet attack such as titanium, 304 stainless steel, or AL-6X.

Alternately, auxiliary measures which have been demonstrated as successful with operating condensers in minimizing tube inlet attack should be provided (e.g., cathodic protection, equipment for treatment of circulating water with ferrous sulfate, and continuous tube cleaning equipment (i.e., Amertap or MAN)).

(c) Operating or Maintenance Procedures

Operating, layup, and startup procedures should be set up to preclude sea water lying stagnant for any significant period of time in the condenser tubes. For example, during wet layup of the cooling system, circulation of fresh cooling water through the condenser for a short period each shift should be required. Alternately, the condenser should be rinsed with fresh water and kept in dry layup. Any water in the intake structure should be periodically circulated.

In addition, it would be prudent to operate with the waterbox high points continuously vented to preclude any accumulation of air bubbles in the waterboxes.

D. Fouling and Cleaning Requirements

1. Operating Experience

Fouling caused by debris and biological growth is a significant problem in surface condensers. Condenser fouling manifests itself in primarily two ways. The first indication of fouling is usually increased backpressure in the condenser resulting from the insulating layer of biological growth on the tube ID inhibiting heat exchange. Corrosive attack (e.g. pitting) under deposits in the tube has also been experienced in a number of condensers. Plants which reported tube leakage due to pitting for the Bechtel survey (reference 14) are summarized in Table IV.D-1.

TABLE 4.D-1

Bechtel Data Summary

Tube Material	Tube Sets Covered by Study	Tube Sets for which pitting corrosion is reported as the cause for leakage	Fraction
Not specified	62	13	.21
Aluminum Bronze	16	16	1.00
Admiralty	153	5	.03
Aluminum Brass	57	45	.79
90-10 Cu-Ni	99	39	.39
70-30 Cu-Ni	79	24	.30
304 SS	147	0	.00
316 SS	34	16	.47
Titanium	33	0	.00
Total	680	158	.23

The tube materials with the highest incidence of pitting corrosion are Aluminum Bronze (100%), Aluminum Brass (79%) and 316 Stainless (47%).

As indicated below nearly all of the incidents of pitting occurred in brackish water or sea water with the majority associated with polluted water. The incidents that did not occur in brackish water or seawater were plants with circulating water through a cooling tower for heat rejection.

TABLE 4.D-2

Summary of Cooling Water Where Pitting Corrosion Occurred (Reference 14)

	SEA WATER				FRESH WATER
Tube Material	Brackish Leak/Total	Polluted Brackish Leak/Total	Clean Sea Water Leak/Total	Polluted Sea Water Leak/Total	Cooling Tower
Not Specified	0/7	9/11	0/2	4/8	0/0
Al-Bronze	9/9	7/7	0/0	0/0	0/5
Admiralty	0/0	1/1	0/0	0/0	4/18
Al-Brass	3/3	21/24	6/6	15/24	0/0
90-10 Cu-Ni	4/31	31/32	0/6	0/0	4/6
70-30 Cu-Ni	0/16	11/15	0/12	13/17	0/8
316 Stainless	7/9	9/17	0/0	0/0	0/0

The number of variables which could have an effect on the pitting reported by plants surveyed requires caution in drawing specific conclusions as to the cause. Biofouling may be only one of the direct causes. Other could be related to the cooling water, methods used to control fouling and to clean the condenser tubes. Table IV.D-3 summarizes the number of plants which chlorinate the circulating water in some form (dose level or frequency of application not indicated) and also experience pitting corrosion.

TABLE 4.D-3
Chlorination and Pitting

Tube Material	Pitting	Chlorine Addition	Pitting and Chlorine Addition
Not specified	13	36	9
Al-Bronze	16	16	16
Admiralty	5	71	1
Al-Brass	45	32	29
90-10 Cu-Ni	39	54	28
70-30 Cu-Ni	24	60	11
304 SS	0	75	0
316 SS	16	26	13
Titanium	0	24	0

There have been a limited number of tests reported in the literature to assess the effects of chlorination on the corrosion behavior of various condenser tube metals in seawater. Tests reported in Reference 36 indicate that chlorination resulted in corrosion acceleration for admiralty brass and aluminum brass. Erratic test results were obtained for 90-10 Cu-Ni with significant corrosion acceleration occurring with some samples and not with others. The test data indicated that 70-30 Cu-Ni corrosion was not affected by chlorination. The Environmental Protection Agency sets limits for the concentration of free available chlorine which may be discharged by a plant at

0.5 mg/l maximum for any one day and the average of daily values for 30 consecutive days shall not exceed 0.2 mg/l. Neither Free Available Chlorine (FAC) nor Total Residual Chlorine (TRC) which includes toxic chloramines may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge FAC or TRC at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES* permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination (Reference 30). Since free chlorine (HOCl) is the most active chlorine species, FAC measurements are normally used for biofouling control and monitoring.

The basic methods of condenser tube cleaning are mechanical and chemical. Many units utilize a combination of one or more mechanical methods along with chemical methods. Table IV.D-4 summarizes the cleaning methods used by the plants surveyed in the Bechtel study. As many as four methods are indicated for a single unit. From a survey of plants that use in-line mechanical cleaning (Reference 35), more than half of them also use brushing or chemical cleaning during periodic shutdowns to supplement the in-line system.

*National Pollution Discharge Elimination System

TABLE 4.D-4

Condenser Cleaning Methods

	Mechanical Methods								Chemical
Material	Amertap/ In-line	Backwash	Rodding or Cabling	Shooting plugs, scrapers, etc.	Water jet	"Picking"	None	Other	Acid or Chemical Agents
Not specified	11	13	8	35	15	2	5	3	15
Al-Bronze	7	9	-	7	9	-	-	7	7
Admiralty	2	68	55	82	35	15	12	-	16
Al-Brass	8	6	4	56	4	3	-	11	5
90-10 Cu-Ni	48	6	-	67	16	1	4	-	22
70-30 Cu-Ni	23	15	6	54	30	3	-	10	16
304 Stainless	7	63	14	59	16	18	20	-	25
316 Stainless	5	14	22	33	11	3	-	-	0
Titanium	4	11	4	18	16	1	-	3	0
TOTALS	115	205	113	411	155	46	41	34	106

The most popular cleaning method is shooting of rubber plugs, nylon brushes, or metal scrapers. According to Reference 33, tube scrapers provide the greatest deposit removal capability of all cleaning methods; removing deposits down to bare metal and polishing the tube surface. All the 41 units that require no cleaning use fresh water sources of cooling water. Twenty-seven of them are on lakes and use no circulating water additives. The remaining 14 have cooling towers and use additives other than chlorine.

The cleaning methods used for tube sets that leaked due to pitting corrosion are summarized below.

TABLE 4.D-5

Cleaning Methods Used On Condensers Experiencing Pitting

	Mechanical Method								Chemical
Material	Amertap/ In-line	Backwash	Rodding or Cabling	Shooting plugs, scrapers, etc.	Waterjet	"Picking"	None	Other	Acid or Chemical Agents
Not specified	7	-	-	11	2	-	-	3	7
Al-Bronze	7	9	-	7	9	-	-	7	7
Admiralty	-	-	-	1	-	-	4	-	5
Al-Brass	8	6	4	45	4	2	-	11	5
90-10 Cu-Ni	28	3	-	31	4	1	4	-	18
70-30 Cu-Ni	11	-	-	24	4	3	-	4	8
316 Stainless	5	4	6	15	6	3	-	-	0
TOTALS	66	22	10	134	29	9	8	25	50

Forty-seven percent of those tubesets that use chemical cleaning experienced pitting corrosion. All of the Aluminum-Brass and Aluminum-Bronze tubes that use chemical cleaning experienced pitting corrosion.

The HEI survey (Reference 34) attempted to determine the cause of tube end leakage only. For tube leaks at locations other than tube-to-tubesheet joints the cause or type of corrosion was not specifically requested. As a result the incidence of pitting corrosion was not mentioned as frequently as in the Bechtel study as the cause of tube leakage. The HEI study indicated that 5-10% of the Aluminum Brass, Admiralty, 90-10 and 70-30 Cu-Ni, and 304 and 316 Stainless Steel experienced pinhole or pitting/corrosion leaks. A few of the questionnaires specifically mentioned tube leaks due to erosion caused by shells and debris blocking the condenser tubes. In one instance, chemical cleaning was reported as the cause of leaks in Aluminum-Brass tubes.

2. Evaluation and Discussion

The mechanical methods for cleaning condenser tubes include on-line systems such as Amertap and M.A.N. as well as off-line manual methods including shooting rubber plugs, nylon brushes, or metal scrapers, water jet, and backwashing. Chemical cleaning includes acid solutions or acid foams to remove deposits. It should be noted that chemical addition (chlorine) to the circulating water to prevent fouling can also be considered a form of chemical cleaning. The more common cleaning methods are briefly described below.

Mechanical On-line Cleaning

On-line mechanical cleaning systems are installed on approximately 200 condensers throughout the United States. NUS Corporation surveyed 64 of these units (Reference 35) to determine (1) the effectiveness of on-line systems in helping maintain the tube side of condenser tubes in a clean condition and (2) whether or not chlorine can be eliminated as a cooling water biofouling control additive. Of the 64 units surveyed 60 used the Amertap system and the remaining 4 used the M.A.N. system.

The Amertap system utilizes sponge rubber balls which recirculate through the cooling water system. The balls are slightly larger in diameter than the tubes and nearly the same density as the water. The balls are pumped in a recirculating loop through the condenser distributing themselves randomly throughout the waterbox. As the balls are forced through the tubes by the pressure differential they wipe away deposits, scale, and bacterial fouling. Two types of sponge balls are available; regular and abrasive coated. The abrasive coated balls are intended primarily for removing scale and deposits from fouled tubes, whereas the regular balls are used to maintain cleanliness of the tubes.

The M.A.N. system utilizes small cleaning brushes for each condenser tube. Each tube is served by its own brush and, at each end, a small plastic cage is fitted to the tube to hold the brushes between cleaning cycles. A cleaning cycle involves reversing the flow through the condenser which forces the brushes through the tubes wiping away deposits, scale, and bacterial fouling.

On-line mechanical cleaning systems have been installed primarily to improve unit efficiency by helping the condenser tubes remain clean and thereby maintaining a lower turbine backpressure. They have been generally successful at accomplishing this goal (Reference 32 and 35). However, the systems have not resulted in reduced chlorination requirements. Chlorination of condenser cooling water is still required to control biofouling on surfaces other than condenser tubes; e.g. cooling towers, tube sheets and Amertap ball collecting screens. In some cases there may be more need to chlorinate with Amertap than without Amertap due to the importance of maintaining the ball collecting screens free of deposits. The most significant limitation for on-line systems is the requirement for removing debris from the cooling water. With the Amertap system, small debris which travels through the condenser tubes collects on the sponge ball collecting screens. The balls are then lost due to improper functioning of the screens or are discarded when the debris is removed from the screens.

Debris buildup on the tube sheets or in the tubes can cause hold up of the balls. Ball hold up in the tubes can cause accelerated corrosion along with reduced cooling water flow. In the M.A.N. system debris can collect on the brush cages which can cause flow loss to the condenser as well as rendering the system inoperable.

Manual Mechanical Cleaning

Manual cleaning is the process of brushing or scraping the inside diameter of the condenser tubes using ramrods or air and/or water pressure to drive the plugs or brushes through the tubes. Manual cleaning requires that the condenser be removed from service, or at least part of it, with the water boxes drained. The process becomes more costly with the increasing size of condensers. Reference 33 reports superior deposit removal capability using metal scrapers compared to brushes or rubber plugs. Although manual cleaning is effective it is intermittent and its effects are sometimes short-lived. Tests have shown a rapid decrease - as much as 15% to 20% - in heat transfer after only ten hours following a thorough manual cleaning (Reference 31).

Chemical Cleaning

Many types of fouling scales and deposits can be effectively removed with acid solutions or acid foams. However, acid cleaning is potentially harmful to tube metal, so its use is restricted to about once a year. Also, fouling recurs rapidly between cleaning. Acids are not particularly effective on slime or algae. The use of chlorine which is effective against slime and algae is being increasingly restricted by government regulation. In addition, it should be noted that chlorine injection may affect the corrosion rate of some condenser tube materials (Reference 36).

3. Recommendations

a. EPRI Sponsored Research

Much published experience with effective control of fouling by chlorination is with chlorine residual concentrations for a longer period each day or at higher concentration than currently allowed. A research effort to determine the effectiveness of chlorination at a number of seawater and brackish water sites within the limits set by the EPA and described in Reference 30 is recommended. The research effort should determine the effectiveness of low level intermittent chlorination combined with shutdown periods in controlling fouling due to macroorganisms and fouling due to microorganisms.

A research effort to determine the effectiveness and potential for corrosive attack of acid (e.g., hydrochloric acid solution, formic acid, citric acid) for chemical cleaning is recommended. This effort should include removal and destructive examination of a small number of condenser tubes to assure that significant corrosive attack on the tubes was not experienced.

b. Equipment Specification Requirements

For brackish or seawater applications, tube materials should be chosen from materials which do not appear to experience pitting attacks such as titanium or possibly AL-6X (as more information on its performance is developed).

For brackish or seawater applications and for stainless steel tube materials an on line mechanical cleaning system (e.g. Amertap or M.A.N.) should be specified. In any event, the condenser arrangement and layout should be specified so that space is available for installation of an Amertap or M.A.N. on line mechanical cleaning system. This would allow backfit of this equipment if later information confirmed the desirability of such an installation.

Chlorination equipment should be specified to minimize problems associated with fouling of the ball collecting screens (Amertap) or the brush cages (M.A.N.). Similarly, the intake screen design should be checked to assure that debris which could foul the ball collecting screens or brush cages is prevented from entering with the circulating water.

c. Operating or Maintenance Procedures

Whether or not mechanical on-line cleaning equipment is installed, periodic manual cleaning of the tube ID with scraper or stiff brushes forced through the tubes is recommended to remove hard deposits or attached organisms.

E. Steam Impingement and Tube O.D. Erosion

Steam impingement from external sources on condenser tubes represents a major problem area in condensers. The number of penetrations into the condenser shell from heater drains, steam bypass lines, steam dump lines, etc., is generally over a hundred. These penetrations, if not properly designed and baffled, can lead to tube failures resulting from O.D. erosion, or tube wearing from broken flow baffles and headers.

1. Operating Experience

Information summarized in Nuclear Power Experience (NPE) indicates a number of plants have experienced tube failures from steam impingement and O.D. erosion. At plants such as Millstone 1, Brunswick 2, Hatch 1, and Arnold, steam impingement was due to improperly designed or inadequate baffling. Redesign and addition of new baffles corrected the problems. In some cases, such as Browns-Ferry 1 and Cooper, some blowdown or drain line valves are now closed during normal operation following incidents during which tubes were damaged due to O.D. erosion when they were left open. Several PWR plants have also reported tube damage due to steam impingement. These include Palisades, Surry 1 and 2, Indian Point 1 and 2, Davis Besse 1, Calvert Cliffs and Ginna. In addition to tube erosion problems, improperly designed baffles often fail due to impingement loads. Instances of failed baffles breaking loose in the condenser and damaging tubes were reported by Maine Yankee, Point Beach 1, Trojan, Beaver Valley 1, and Arkansas 1.

The results of the EPRI sponsored Bechtel study (Reference 14) identifies steam erosion as a cause of tube leakage for 10% of the units surveyed. In addition, tube damage due to falling objects, missiles, etc., is indicated for 9% of the units. Some of these failures could have been due to broken baffles.

The results of the HEI survey (Reference 34) indicate that 16% of the units surveyed experienced tube leakage due to baffle or O.D. erosion problems.

2. Evaluation and Discussion

Baffle Design

Properly designed and installed flow baffles can be used to prevent O.D. erosion of condenser tubes (Reference 13). The baffles must effectively distribute the incoming steam or two phase flow so that high velocity streams do not impinge on the tubes. The baffles and their supports must also have sufficient structural strength to withstand the imposed loading. In this regard, baffles and supports should be designed to handle maximum anticipated flows through the penetration. A conservative design loading can be obtained as follows:

A fluid jet impinging perpendicular to a flat plate exerts a maximum load equal to

$$F_{max} = 2\ P_o A \qquad (1)$$

where

P_o = stagnation pressure at the discharge into the condenser

A = discharge pipe area

Equation 1 is obtained from integrating the momentum equation and assumes subcooled liquid, non-flashing choked flow. For saturated liquid or two phase mixtures the jet load varies between 1.0 P_oA and approximately 1.3 P_oA (Reference 51).

The stagnation pressure is the pressure that exists if a flowing fluid is brought to rest (zero velocity) without losses (isentropically). A simple pitot tube device is most commonly used for measuring stagnation pressure. In the absence of measured stagnation pressures near the discharge into the condenser, the stagnation pressure can conservatively be estimated by using the maximum design static pressure existing at the stagnant source of the discharge fluid adjusted for variations in head from the source to the discharge point. This neglects losses due to friction, turning losses, and losses due to expansion/contractions. For example, a heater drain line stagnation pressure could be estimated from the saturation pressure corresponding to the feedwater temperature exiting the heater plus changes in elevation head from the drain to the discharge.

The baffles and supports should be designed to withstand an infinite number of load cycles between zero and 2 P_oA. Impingement loads can be reduced if the flows are directed at an angle to the baffles rather than perpendicular. However, the possibility that the flow reflected from the baffle could impinge on the tube bundle would also have to be evaluated and baffle designs which could allow such reflected impingements avoided. Attachment of a flow splitting wedge (e.g., angle iron) to the face of a baffle will help reduce the cycling of the load as it contacts the baffle and splits in opposite directions. Attachment of baffles and support structures should be made with full penetration continuous welds. Several instances of baffle failures reported in Nuclear Power Experience were due to failure of partial penetration welds.

Tube Material

Titanium and stainless steel are considered to be the most resistant to O.D. erosion according to Reference 16. This is consistent with Speidel's presentation on "Steam Impingement Attack on Condenser Tubes" summarized in Reference 44. However, Reference 52 indicates an erosion resistance for aluminum bronze which is roughly equivalent or slightly better than that of austenitic stainless steel. The Bechtel study (Reference 14) indicates approximately equal failure rates due to O.D. erosion for all tube materials (5-10%) with the exception of 90-10 Cu-Ni which indicates a failure rate of 30%. Data presented in Reference 53 also indicates a lower erosion resistance for Cu-Ni alloys. Regardless of the tube material selected, careful design of inlet flow headers and baffles are required if O.D. impingement erosion is to be prevented.

3. Recommendations

a. EPRI Sponsored Research

The erosion behavior of materials has been very difficult for researchers to quantify. The difficulty lies in the fact that erosion resistance is dependent on many factors including velocity of impinging fluid, angle of impingement, drop size or solid jet, test specimen temperature, test method, and material properties (e.g., hardness). It is recommended that EPRI sponsor work to determine the relative resistance of common condenser tube materials to impingement erosion under test conditions similar to those existing in a condenser environment utilizing techniques similar to those used for studying tubine blade erosion. The study should determine the effect of steam velocities and quality on erosion rates, and if a threshold velocity exists below which erosion does not occur.

b. <u>Equipment Specification Requirements</u>

Condenser equipment specifications should require baffling of all drains and condensate returns to preclude impingement erosion. The Contractor should submit for approval the design and arrangement of all impingement baffles. The justification to be submitted by the contractor should consider steam and condensate velocites for the worst condition, i.e., high mass flow from drains at high condenser vacuum, and shall include:

- Maximum anticipated loading on the baffles and baffle support structures.
- Maximum induced vibration to preclude fatigue failure of baffles.
- Consideration of direct and reflected impingement velocities.

All baffle installations should use full penetration welds. The specification should require that the contractor provide detailed inspection sheets to facilitate periodic verification that baffles are trouble free and that tubing is not experiencing impingement erosion. The contractor should be required to ensure that there is suitable access to allow necessary inspections within the assembled condenser. After installation the Contractor should be required to perform and document the initial baseline inspection of the drain baffling. A special inspection schedule and procedure should be submitted for approval covering tubing areas that could be impinged by high local steam velocities in the exhaust neck. Inspections by the Contractor after the condenser is in-service should be required and the Contractor should be required to install necessary local baffles where any impingement is evident.

The specification should require that the Contractor ensure that arrangement of the exhaust neck provides protection of adjacent tubes from direct impingement by steam and/or moisture through the exhaust neck. In addition, impingement protection against failed turbine parts should be provided as far as practicable without adversely affecting the flow distribution of steam into the tube bundle. The arrangement should be required to be submitted to the Purchaser for approval.

If steam heating of condensate in the hotwell is required for low power levels the specification should require that protection against impingement erosion of any tubing and of the hotwell walls is provided.

The specification should require that the Contractor submit for Purchaser's approval proposed condenser design features to accept flow from the Turbine Bypass system. This shall include supporting technical justification and analysis results for the specific design.

The specification should also require design features to preclude the make-up water being entrained in the steam flow and impinging on the condenser tubes. Specifically, the specification should require that the Contractor submit for approval supporting justification, such as engineering analysis, test data or service experience of similar equipment, for the design arrangement of the make-up water piping and water inlet into the condenser.

c. Operating or Maintenance Procedures

A pre-operational inspection of the condenser should be made to verify proper installation of all baffles. The inspection should also ensure that all construction materials (e.g., platforms and staging) have been removed.

Annual inspections should be performed to check the integrity of baffling and to determine if impingement erosion is occurring in the bundle. The Contractor should provide a procedure and checklist for the inspection with space provided to record the results. Additional baffles should be designed and installed for any areas where impingement is evident.

F. Flow Induced Vibration

Flow induced tube vibration has resulted in a significant number of tube failures. The tube vibrations can lead to several types of tube damage. Severe vibrations in which the tubes impact at mid-span can lead to tube thinning and failure at the point of impact. Less severe vibrations can also be damaging, leading to fatigue failures, generally at points adjacent to a tube support or tube sheet. Vibration can also result in fretting and failure of tubes at the tube and tube support intersection. Whether tube damage is due to fretting, impact, or fatigue, large numbers of tubes are likely to be affected. Flow induced vibration is one failure mechanism which can result in sudden large amounts of leakage of the cooling water into the condenser. Accordingly, it is important in condenser design to consider the possibility of flow induced vibration and preclude its occurrence.

1. Operating Experience

Table IV.F.1 is a summary of information on condenser tube vibration incidents and failures that are reported in Nuclear Power Experience, Reference 13. Nuclear Power Experience contains 149 reports of PWR and BWR condenser incidents. Of these, 18 or 12% are attributed to flow induced vibration. Review of Table IV.F.1 illustrates the number of shutdowns and power reductions that can be required when a condenser is prone to flow induced vibration failures. For example, the Zion 1 unit experienced tube leaks in August and November of 1974 and again in February of 1975. By May of 1975, a total of 230 tubes had been plugged and flow induced vibration had been identified as the failure mechanism. Moreover, Zion 2 was also experiencing vibration failures and had a total of 250 tubes plugged. To prevent further tube damage from vibration, anti-vibration clips were installed in the Zion 1 and Zion 2 condensers. In May of 1975, the utility estimated that Zion 1 had experienced 244 hours of forced outage resulting from flow induced vibration and that Zion 2 had experienced 504 hours of forced outage, also due to flow induced vibration.

As apparent from this example, and the other reports presented in Table IV.F.1, flow-induced vibration can require lengthy shutdowns or power reduction to locate and plug failed tubes.

An EPRI sponsored survey of condenser operating experience conducted by Bechtel, Reference 14, indicates that of the 680 tube sets covered by the field survey 56 experienced flow induced vibration. The Bechtel results are summarized in Table IV.F.2.

The Bechtel study reports that 50% of failures with "titanium tubing are directly attributable to vibration damage." This indicates that the potential for flow induced vibration was not adequately considered when the tubing material was selected as, or changed to, titanium. Titanium has a modulus of elasticity lower than most of the other common condenser tube metals, and the tubing generally has thinner walls which take advantage of titanium's higher strength to offset its lower thermal conductivity. Hence, titanium tubing is not as stiff as the tubing it replaces and may require additional support to avoid damage due to flow induced vibration. In summary, at the design state every condenser must be evaluated for potential vibration problems. In existing units, the design must be thoroughly reevaluated for potential vibration problems when critical parameters such as tubing type, steam flow rates, or flow distribution are changed.

Results of a survey conducted by the Heat Exchange Institute (HEI) are summarized in Appendix B. The survey included 527 tube sets of which 31, or 6%, experienced condenser leakage problems as a result of flow induced vibration.

In addition to the evidence cited from the HEI survey, the Bechtel study, and Nuclear Power Experience, published reports, References 15, 16, 17 and 18, indicate that utilities are experiencing condenser reliability and availability problems that are due to flow induced vibration tube failures.

2. Evaluation and Discussion

This section first discusses the mechanisms of flow induced vibration and the design rules to prevent flow induced vibration from occurring. The second part of this section discusses the effect on tube natural frequency and potential for flow induced vibration of tube to support plate hole clearance and the axial load on the tubes.

a. Flow Induced Vibration Mechanisms and Design Rules

Analyses and studies of flow induced tube vibration have not resulted in a consensus on a reliable design guide for the prevention of flow induced vibration in condensers. A great deal of effort has been focused on identifying the mechanisms of cross-flow excitation in tube banks and developing correlations which describe the mechanisms involved. At the same time some design rules for limiting flow induced vibration in condenser tube banks do not directly address the mechanism of tube vibration. These design rules are empirically based; for example a requirement is placed on tube stiffness to meet a specific criteria on mid-span deflection under assumed sonic velocities.

The potential mechanisms for flow induced vibration and two design rules to prevent flow induced vibration are discussed below. The mechanisms and design rules which are covered are:

- Vortex shedding
- Turbulent buffeting
- Fluid elastic instability
- Westinghouse correlation
- Design rules to limit tube deflection

(1) Vortex Shedding

Tubes can be excited by vortex shedding when the frequency of vortex shedding in the tube bank reaches the tube natural frequency. The criterion used to determine the possibility of vortex shedding induced vibration is the Strouhal number, defined by

$$S = \frac{fd}{U} \qquad (1)$$

Chen, in Reference 23, has published experimental values of the critical Strouhal number for various tube array configurations. For a condenser, if it is assumed that the tube pattern is triangular and that the pitch to tube diameter ratio is 1.25, Chen's data indicate that the minimum critical Strouhal number will be 0.15. However, for most configurations the Strouhal number will be significantly higher.

As indicated by calculations in Appendix C (Part 2) a lower bound on the damping parameter, $m\delta/\rho d^2$, for application involving condensers is 560, assuming a 22 gage, 1.25 in. diameter titanium tube, a log decrement of .036, and saturated conditions at 2.85" of mercury.

A review of the information plotted on Figure IV.F.1 shows that for $m\delta/\rho d^2$ of 560 the velocity at which oscillations due to vortex shedding occurs will be significantly lower than the velocity for which fluid elastic vibrations would be expected to occur. This implies that there is less kinetic energy available from the flow stream at vortex shedding resonance than at the fluid elastic critical point.

Tests reported in Reference 59 indicate that vortex shedding will excite tube vibration for only about 4 rows into a tube bundle.

In summary, vortex shedding resonance is a potential mechanism for exciting tube vibration and must be considered in condenser designs. Either vortex shedding frequency resonance should be avoided for conditions of flow and pressure at which the condenser is expected to operate at steady state or the energy input at resonance must be shown not to result in unacceptable tube vibrations. This may result in vortex shedding resonance at very low power.

(2) Turbulent Buffeting

Turbulent buffeting generally occurs at flow rates above those associated with vortex shedding resonance. The tube excitation is due to random pressure fluctuations in the turbulent flow.

Tests reported in Reference 59 with tubes with a natural frequency of 24 hz indicated that tube response was random due to turbulent buffeting and no periodic motion was observed. A review of the turbulent power spectra in these tests provided support for the suggestion by Wambsganss in Reference 61 that the peak in the turbulence spectra for cross flow in tube banks occurs at a Strouhal number of

0.21. Unlike vortex shedding which appears to be limited to exterior rows of tubes in a bundle, turbulent buffeting can occur throughout a tube bundle.

In summary, turbulent buffeting will occur at higher flows than for vortex shedding resonance and will have a greater potential for energy transfer to the vibrating tubes. Like vortex shedding, turbulent buffeting should be considered in condenser designs by assuring that the peak in the turbulence spectra does not occur at normal power levels or by demonstrating that unacceptable tube vibrations do not result.

(3) Fluidelastic Instability

Analyses and studies of tube vibration indicate that the fluidelastic flow induced vibration mechanism, first described by Conners, Reference 19, can result in destructive tube oscillations. The basic mechanism is that a tube which has been displaced from its equilibrium position alters the flow field, upsetting the resulting force balances on the tubes. If the work that is extracted from the flowing fluid by the displaced tube array is greater than that which can be dissipated by tube damping, then large amplitude vibrations will result.

The point at which fluidelastic instability of a tube array occurs is determined by a critical flow velocity. Flow velocities increased beyond the critical velocity produce vibrations of increasingly large amplitudes.

In Reference 19 the critical velocity for fluidelastic vibrations is defined in terms of tube stiffness, mass, damping parameters, and fluid density.

$$\frac{U_c}{f_n d} = K \sqrt{\frac{m\delta_n}{\rho d^2}} \qquad (2)$$

Where

U_c	=	Critical velocity in the gap between adjacent tubes in the same transverse row.
f_n	=	Natural frequency in the nth mode of vibration
d	=	Tube diameter
K	=	Threshold instability constant; dimensionless
m	=	Mass per unit length

δ_n = Logarithmic decrement for a tube vibrating in the nth mode and in still fluid of density ρ; dimensionless.

ρ = Fluid density

The logarithmic decrement is a function of the rigidity of the tube and tube support, the tube material, and the fluid outside of the tube (see Reference 17). The interaction and influence of these factors is complicated and therefore, the log decrement must be experimentally determined. Table IV.F.3 presents some values that have been reported in the literature. The lowest value is .036, reported for a 90-10 copper-nickel tube. Reference 17, published in 1978, states that Westinghouse condenser design work at that time used a log decrement of .036 for all tube metals.

The quantity K, which is experimentally determined, is the threshold instability constant. It is a function of the tube pattern, the pitch to diameter ratio, and the flow direction into the tube pattern. The use of this quantity assumes that the flow field is essentially uniform in the transverse direction. Pettigrew et. al., in Reference 20, compiled data from several investigators, and added data of their own to obtain the results reproduced here in Figure IV.F.1. The line K = 9.9 was established by Connors in 1970 (Reference 19) from his experiments with single row arrays in air. The line K = 6.6 was determined in 1978 by Pettigrew et.al.,(Reference 20) to apply to liquid flow. Both Pettigrew et. al. and Gorman (Reference 20 and 22, respectively) recommend K = 3.3 for design purposes. Connors has published further results (Reference 28), not included in Figure IV.F.1, that are summarized in Table IV.F.4.

Correlations which differ from that of Connors have been proposed to describe the critical velocity for fluidelastic instability.

Reference 62 reports the results of experimental measurements of critical flow velocities for water through six rectangular tube arrays with different spacing, mass ratio, damping and de-tuning. Based on these results, a correlation of the form.

$$\frac{U_c}{f_n d} = \frac{1}{\left[\beta_1 + \beta_2 \quad \frac{m\delta_n}{\rho d^2}\right]} \qquad (3)$$

is suggested. In this equation, β_1 & β_2 are experimentally determined constants. Reference 59 reports the results of wind tunnel tests which along with those reported in Reference 21 extend the results for tube bundles to values of $\frac{m\delta_n}{\rho d^2}$ which are considerably higher than those covered by the tests in Reference 62 and which approach those which could exist in condenser tube arrays. Based on review of this data, Weaver and Grover in Reference 59 suggest the following correlation for the critical velocity for fluidelastic instability for the tested array.

$$\frac{U_c}{f_n d} = 7.1 \left[\frac{m\delta_n}{\rho d^2}\right]^{0.21} \tag{4}$$

Based on theoretical considerations Reference 59 goes on to suggest that an equation of the form below would provide a better relationship between design parameters.

$$\frac{U_c}{f\ g} \propto \left[\frac{m}{\rho d^2}\right]^{1/2} \delta^n \tag{5}$$

(4) Westinghouse Design Correlation

Reference 15, 16, and 17, describe a correlation that is used by Westinghouse Electric for tube vibration analysis of condensers.

The correlation is

$$S = 1.22 \times 10^{-4} L^4 \left[\frac{\rho V^2 d}{EI}\right] \quad (6)$$

where V = Turbine exhaust flange velocity, ft/s

L = Length of unsupported tube span, in.

d = Tube diameter, in.

E = Modulus of elasticity, lb_f/in^2

I = Tube moment of inertia, in^4

S = Severity factor

Development of this equation assumes a simply supported beam in calculation of the tube natural frequency and also assumes a log decrement of 0.036.

The magnitude of the severity factor is interpreted as follows:

Severity Factor	Interpretation
$S < 1$	Conservative
$1 \leq S \leq 1.5$	Low probability of vibration
$S \geq 2$	High probability of vibration

A comparison of the Connors and Westinghouse equations for evaluation of tube vibration in condensers is presented in Appendix C (Part 1).

To make the comparison, the ratio of the predicted critical flow velocities is formed. The K factor is varied between 3.3 and 9.9, the tube diameter is varied between .875 and 1.25 in., and the pitch to diameter ratio is varied between 1.2 and 1.5. The comparison shows that the ratio of the Connors critical velocity to the Westinghouse critical velocity can lie between 0.12 and 0.83. However, it should be noted that the comparison conservatively assumes that flow distribution around the bundle is negligible.

The trunk velocity, used as the reference velocity by the Westinghouse correlation, was assumed to persist into the tube bundle without redistribution around the bundle. This flow redistribution, if taken into account would result in a more favorable comparison between the Westinghouse correlation and the criteria for fluidelastic instability. However, the comparison does point out the importance of using the actual local velocity over the tubes in any evaluation of the potential for flow induced vibration problems.

(5) Design Rules Which Limit Tube Deflection

In Reference 24, Sebald and Nobles, propose design rules for steam surface condensers which essentially limit the mid-span deflection due to drag forces imposed by assumed sonic velocity around the tubes. These design rules as applied to feedheaters and updated to include consideration of both lift and draft effects were discussed in Reference 60. Basically, the design approach requires that a support plate spacing be chosen so that a tube with the resulting length and simple support end conditions will deflect less than one half the distance between adjacent tubes when subjected to a load imposed by sonic velocity at condenser conditions.

$$W = \frac{\rho Vs^2 d}{2g\text{x}12} \left[C_D^2 + C_L^2 \right]^{1/2} \quad (7)$$

where W = loading on tubes in lb/in

ρ = fluid density in lb/cu ft

Vs = sonic velocity in ft/sec

g = gravitational acceleration in ft/sec^2

d = diameter, ft

C_L = lift coefficient

C_D = drag coefficient

Reference 18 notes that a similar procedure is included in the HEI Standards as a recommended but not mandatory requirement and recommends that an assumption be made that the local cross flow velocity past any tube will not exceed three times the average velocity at the turbine exhaust connection to the condenser or sonic velocity, whichever is less. Following these guidelines results in a choice of the condenser pressure at which three times the exhaust trunk velocity equals sonic velocity as the pressure to determine density and velocity for the tube loading calculation.

b. Parameters Which Affect Tube Natural Frequency

The effect of tube to support plate hole clearance and axial load on tube wear characteristics and the natural frequency of condenser tubes are discussed in the following paragraphs.

(1) Tube to Support Plate Hole Clearance

The clearance between the tube and tube support hole is a factor important to the rate of fretting wear due to vibration, to the tube damping characteristics, and to the tube natural frequency.

The tube to tube hole clearance affects the end fixity of a tube span and therefore directly affects the tube span fundamental frequency. The smaller the clearance the greater the degree of end fixity and the higher the fundamental frequency. However, by decreasing the clearance less damping may be introduced. The effect of the tube to tube hole clearance on the fundamental frequency and on damping characteristics cannot be computed analytically. Normal practice in frequency calculations is to assume that a tube span is simply supported at both ends, excepting cases where one tube end is fixed in the tube sheet.

Data obtained by Sebald and Nobbles (Reference 24), on tube natural frequency as a function of tube hole clearance are summarized in Table IV.F.5. Kissel (Reference 25), reports that the natural frequency for a 3/4" tube varied from 36 to 22.5 cps as the radial clearance was increased from 0 to .011 in. and that there was no perceptible change in natural frequency when the clearance was in the range .0025 to .011 in.

Blevins, in Reference 26, has shown that increasing the tube to tube hole clearance will increase the rate of fretting wear. His data are reproduced in Figure IV.F.2.

(2) Effect of Axial Stress on the Tube Natural Frequency

Peake et. al., in Reference 16, demonstrate how tubes in the middle of a condenser bundle are placed into compression and the tubes at the periphery placed into tension by the hydrostatic forces in the water boxes. Compression or tension will change the tube natural frequency from that obtained when the tube is unstressed in the axial direction. Sebald and Nobles in Reference 24, report experimental values of the natural frequency that are 36.5, 32.5, and 30 cps for a tube span that is placed under 2000 psi tension, zero stress, and 2000 psi compression respectively. Data from Kissel, Reference 25, support the observation from the data of Peake et. al., that the natural frequency of a tube is decreased when a compressive load is applied and, conversely, increased under a tensile load.

Timoshenko et. al., in Reference 27, relate the sign and magnitude of the axial stress to the fractional change of the natural frequency.

$$\frac{f_{n,s}}{f_{n,o}} = \sqrt{1 + \frac{Sl^2}{n^2 EI\pi^2}}$$

where

$f_{n,s}$ = natural frequency in nth mode with axial stress S

$f_{n,o}$ = natural frequency in nth mode with zero axial stress

S = axial stress, plus for tension, negative for compression

l = span length

n = mode of vibration

E = modulus of elasticity

I = moment of inertia

With the above equation from Timoshenko, the affect of axial stress on the natural frequency of a tube span for simple support end conditions can be simply determined from the magnitude of the stress.

3. Recommendations

a. Recommended Tasks for EPRI Support

A great deal of effort has been applied to developing and testing correlations which describe mechanisms which might be involved in condenser tube flow induced vibration problems. The element which appears to be lacking is application of the various correlations and design rules to field conditions. It is recommended that a program of analysis of condensers which have experienced tube vibration problems and also of condensers which appear to be free of tube vibration problems be set up by EPRI in conjunction with cooperating utilities. The calculational methods to be applied should include vortex shedding evaluations using data from Reference 23, turbulent buffeting evaluations using information from Reference 59, fluidelastic evaluations using correlations proposed by Connors (Reference 28) and the alternate correlation proposed by Weaver and Grover (Reference 59). In addition, the degree to which the condenser configuration meets the design rules proposed by Sebald and Nobles, Reference 24, should be determined. When flow induced vibration is present, the mechanism which is responsible should be identified. In the absence of flow induced vibration, it should be confirmed that the equations predict margin with respect to flow induced vibration.

b. Recommended Equipment Specification Requirements

It is recommended that the following items which concern flow induced vibration be invoked in condenser equipment specifications:

1) It shall be demonstrated by the Contractor that each flow entry into the condenser is acceptable in accordance with 2), 3), 4), and 5) below.

2) The critical flow for fluid elastic vibration shall be determined using the calculational approach presented by H. J. Connors in his 1977 paper, "Fluidelastic Vibration of Heat Exchanger Tube Arrays" but using the more conservative exponent of 0.21 on the damping parameter ($m\delta/\rho d^2$) proposed by Weaver and Grover in Reference 59. In the absence of model test data for the threshold instability constant and the logarithmic decrement, values for these constants shall be assigned as follows:

$$K = 7.1$$

$$\delta = 0.036$$

3) Calculation of the actual flow velocity for each flow entry into the condenser shall be based upon the worst flow conditions.

4) To meet the acceptance criteria the actual flow velocity shall be less than or equal to 80% of the critical flow velocity as calculated with the equation and constants specified in 2) above.

5) Calculations shall demonstrate that the design rules for tube mid-span deflection proposed by Sebald and Nobles in Reference 24 and adjusted to include the lift coefficient as described in Reference 60 are met.

6) Fabrication of the condenser shall not commence until the Purchaser has approved the vibration analysis results.

7) The tolerance on size of holes for the tube-sheets and support plates shall be per HEI standards.

8) The Contractor shall inspect final dimensions of holes in support plates and tube sheets and record the inspection results. All deviations from design tolerances shall be submitted to the Purchaser as nonconforming material. The final hole inspection shall be a witness point for the Purchaser.

c. <u>Recommended Changes to Operating or Maintenance Procedures</u>

If the tube bundle of a condenser has been staked to improve its margin against flow induced vibration, it is recommended that periodic inspections be made to assure that the stakes are in place and are effective.

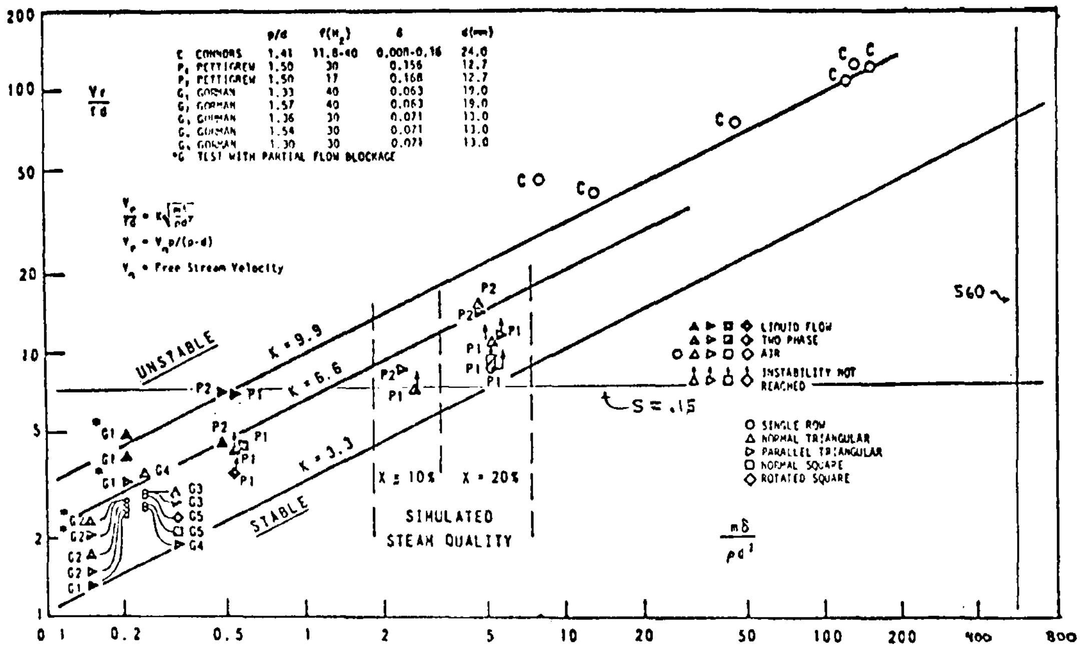


Figure 4.F-1. Stability Diagram for Tube Arrays*

* Adapted from Reference 20

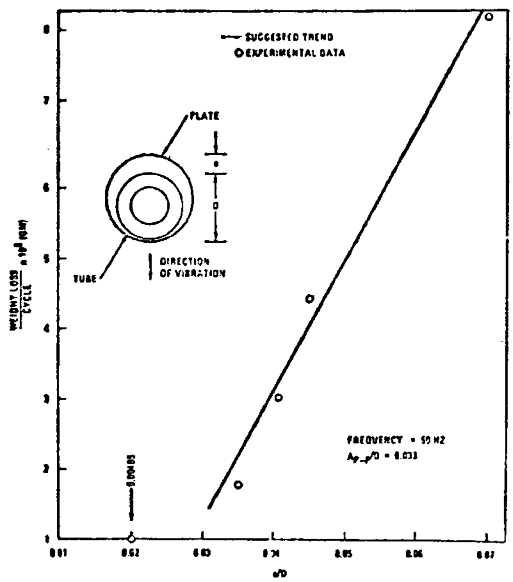


Figure 4.F-2. Fretting Wear Rate as a Function of Tube to Tube Hole Clearance*

* From Reference 26

TABLE 4.F-1

Summary of Nuclear Power Experience Reports for Condensers Experiencing Vibration Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Vibration	Problem Category: Leak Check	Problem Category: Staking
Ginna	PWR	January 1971	Repair condenser tube leaks		X	
		Spring 1971	Neoprene lacings for vibrating tubes	X		X
Palisades	PWR	February & March 1972	Several shutdowns to repair 5 failed tubes	X	X	
		April 1972	Leaking tubes are plugged	X	X	
		April 1972	2000 stiffening stakes installed			X
		June 1972	Two power reductions to search for tube leaks		X	
		September 1972	1000 additional stakes installed			X
		August 1973	1 tube fatigue failure	X	X	
		August 1973	Staking of vibration prone areas			X

TABLE 4.F-1 (Continued)

Summary of Nuclear Power Experience Reports
for Condensers Experiencing Vibration Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Vibration	Problem Category: Leak Check	Problem Category: Staking
Palisades (Contd)	PWR	December 1974	All 27000 tubes replaced with 90-10 Cu-Ni			
		October 1976	232 tubes plugged. Vibration suspected.	X	X	
		January 1977	5 tubes plugged	X	X	
Robinson 2	PWR	Spring 1971	12 condenser tubes failed due to vibration. Tubes plugged and staking accomplished.	X	X	X
		1973-1974	Leakage in 233 tubes		X	
Zion 1	PWR	August 1974	Leaking tubes are plugged		X	
		November 1974	Leaking tubes are plugged		X	
		February 1975	Leaking tubes are plugged		X	
Zion 1 & 2		1974-1975	Vibration identified as failure mechanism	X		

TABLE 4.F-1 (Continued)

Summary of Nuclear Power Experience Reports
for Condensers Experiencing Vibration Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Vibration	Problem Category: Leak Check	Problem Category: Staking
Zion 1 & 2 (Contd)	PWR	May 1975	230 tubes have been plugged on unit 1; 250 on unit 2.	X	X	
		1974-1975	Anti-vibration clips installed, units 1 and 2			X
		1974-1975	Total forced outage due to leaks is 244 hours for unit 1 and 504 hours for unit 2			
Beznau 1	PWR		Vibration causes touching of tubes. Supports installed.	X		X
Chooz-Sena	PWR	December 1973	Titanium tubes subject to vibration cracking	X		
Indian Pt. 2	PWR	February 1975	22 tubes leaking due to excessive movement. Tubes plugged and staked.	X	X	X
Prairie Island 1	PWR	June, July, November 1974	Tube plugging		X	

TABLE 4.F-1 (Continued)

Summary of Nuclear Power Experience Reports for Condensers Experiencing Vibration Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Vibration	Problem Category: Leak Check	Problem Category: Staking
Prairie Island 1 (Contd)	PWR	January 1975	2 shutdowns and 1 power reduction to locate leaks		X	
		February 1975	3 power reductions to locate and plug leaking tubes		X	
		March-April 1975	5 power reductions to plug leaking tubes		X	
		April 1975	Suspect tubes plugged. Modifications to stop tube vibration.	X	X	X
Davis Besse 1	PWR	February 1978	68 tubes plugged. Extra supports possibly needed.	X	X	
Millstone 1	BWR	1972	Numerous tube failures during 18 months of operation. Caused by pitting and vibration. Staking of problem areas accomplished.	X	X	X
Oskarshamn 1	BWR	1970	Vibration due to improper baffling	X		

TABLE 4.F-1 (Continued)

Summary of Nuclear Power Experience Reports for Condensers Experiencing Vibration Problems

				Problem Category		
Unit	Type	Date	Problem Description	Tube Vibration	Leak Check	Staking
Muhleburg	BWR	May 1973	Modifications to prevent vibration	X		X
Peach Bottom 2	BWR	June 1974	Leaking tube plugged		X	
		July, November 1974	Power reductions to plug leaks. Failures due to vibration from poor baffling.	X	X	
Oyster Creek	BWR	October, December 1976	Condenser retubed with titanium. Tube failure due to vibration soon experienced.	X		
Brunswick 2	BWR	August 1977	Tube staking for localized vibration problem.	X	X	X

TABLE 4.F-2

Incidence of Vibration Problems
From Bechtel Field Survey

Description	No. of Tubesets
Tubesets covered by field survey	680
Tubesets experiencing tube vibration	56
Tubesets experiencing vibration which added staking	47
Tubesets not staked and reporting leakage due to vibration	9
Tubesets staked with no leaks due to vibration	27
Tubesets staked and reporting leakage due to vibration	20 (1)

Note: (1) Leakage may have occurred prior to addition of staking.

TABLE 4.F-3

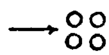
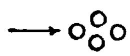
Experimental Values of the Logarithmic Decrement

Component Description	Environment	Material	δ_o	Reference
Process Heat Exchanger	Water	Stainless Steel	.104	20
Process Heat Exchanger	Water	Stainless Steel	.156	20
Steam Generator Model	Water	Stainless Steel	.136	20
Steam Generator Model	Water	Stainless Steel	.073	20
Moderator Heat Exchanger	Water	Incoloy 800-T	.046	20
Moderator Heat Exchanger	Water	Incoloy 800-T	.042	20
Fuel Element	Air-Water	Ziracloy - 2	.375	20
Steam Generator Model	Steam-Water	Stainless Steel	.510	20
Tube with Multiple Supports	Air	Titanium	.0842*	17
Single Tube Span	Air	Plastic	.106*	21
Single Tube Span	Air	Plastic	.551*	21
Single Tube Span	Water	Stainless Steel	.071	22
Single Tube Span	Water	Stainless Steel	.063	22
Heat Exchanger	----	90-10 Cu-Ni	.036	15

* Average Value

TABLE 4.F-4

The Threshold Instability Constant

Fluid	Array	K*	T/D**
Air or Water		$K = .37 + 1.76\,\frac{T}{D}$	$1.41 \le \frac{T}{D} \le 2.12$
--		4.0	1.25

* Data from Connors, Reference 28.

** Pitch to tube diameter ratio.

TABLE 4.F-5

Fundamental Frequency and Tube to Tube Hole Clearance*

Diametral Clearance, in.	CPS**
0	44.5
.01	38.0
.02	33.5
.03	28.0

* Data from Reference 24

** Admiralty metal tube and 49 3/8 in. tube span.

G. Corrosion Attack in the Air Removal Section

Tube failures in the air removal section by corrosion or stress corrosion cracking occur, largely because of the local high concentrations of ammonia. The rate of ammonia corrosion and potential for stress corrosion cracking is increased by air in-leakage to the condenser which raises the air removal section oxygen and carbon dioxide concentrations. Ammonia corrosion can lead to pitting and pin hole leaks. Stress corrosion cracking can also produce tube failures.

1. Operating Experience

Information summarized in Nuclear Power Experience shows that Millstone 2 and Dresden 1 are experiencing steam side corrosion.

The Bechtel survey for EPRI indicates that corrosive attack in the air removal section occurs in approximately 21% of condenser units. Table IV.G.1 summarizes data from the Bechtel survey for the different tube materials used in air removal sections. Units tubed with admiralty, aluminum brass, aluminum bronze, or arsenical copper had the highest incidence of air removal section corrosion. Units tubed with 70-30 Cu Ni, 90-10 Cu Ni, stainless steel, or titanium had the lowest incidence of air removal section corrosion.

In the HEI survey, 65 of 527 units surveyed, about 12%, report air removal section corrosion problems. Information from the HEI survey is summarized in Table IV.G.2 for various air removal section tube materials in the same manner as done for the Bechtel survey in Table IV.G.1. The HEI survey results are similar to the Bechtel survey results; admiralty and aluminum brass had the highest incidence of corrosion problems in the air removal section, while 70-30 Cu Ni, 90-10 Cu Ni, stainless steel, and titanium had low incidences of corrosion.

2. Evaluation and Discussion

Failure of tubes in the air removal section by corrosion or stress corrosion cracking is largely due to local high concentration of ammonia. The sources of ammonia are various chemical additives, such as hydrazine, morpholine, and cyclohexylamine, which are added to the feedwater to scavenge free oxygen and/or controlling pH thereby limiting corrosion in the feedwater system. At the temperatures encountered during steam generation the chemical additives decompose, with ammonia being one of the decomposition products. The ammonia concentrates in the condenser air removal section. In reporting on their review of the literature, Popplewell and Bates (Reference 45) indicate that ammonia concentrations in the air removal section can range from 50 to 500 ppm with typical values being at the 200 ppm level or less. In Reference 46, Aoyama, et al, report measurements of air removal section ammonia concentrations of 45 to 2700 ppm in steam and 4 to 258 ppm in condensate at a pH of 9.4.

Ammonia concentrates in the air removal section through the phenomenon termed the "reboiler" effect. In air removal sections noncondensable gases are drawn over the coldest tubes in the condenser. When warm ammonia vapor meets the cold droplets of water on the tubes, the ammonia goes back into solution. The droplets of water fall from the tubes and are met by warm rising steam which heats the droplets and drive out absorbed ammonia. The ammonia vapor rises, is absorbed by cold water droplets and the cycle repeated (see Reference 15 and 36).

Coit, in Reference 15 and Coit, et al, in Reference 38 report that open core air removal sections -- as opposed to shrouded air removal sections -- are less susceptible to ammonia attack. Condensate continuously falls through the air removal section, providing a diluting action for condensate on the tubes where ammonia would tend to accumulate.

High concentrations of ammonia in the air removal section can lead to tube failures through corrosion or stress corrosion cracking.

a. Ammonia Corrosion

Ammonia corrosion can lead to pitting on the tube surface and condensate grooving at points adjacent to support plates and tube sheets. The term condensate grooving refers to the corrosion produced by flow of a concentrated ammonia solution over a tube surface.

Ammonia corrosion on a susceptible tube surface requires that ammonia, moisture, and oxygen be present. (See Reference 48 for a description of ammonia corrosion chemistry). However, Popplewell and Bates in Reference 45, and Tice and Venizelos in Reference 50, report that addition of carbon dioxide results in markedly increased corrosion rates.

The susceptibility of various tube materials to ammonia corrosion is given in Table IV.G.3, adapted here from Reference 47. Other references (38, 45, 49, and 50) report similar rankings of tube material resistance. Titanium, stainless steel, 70-30 Cu Ni, and 90-10 Cu Ni are highly resistant to ammonia corrosion.

b. Stress Corrosion Cracking

Stress corrosion cracks can appear very suddenly in metals that are in corrosive environments if tensile stresses are present. In the air removal section of condensers, the corrosive environment is provided by moisture, ammonia, and oxygen.

Residual stresses probably account for the majority of tube failures caused by stress corrosion cracking (Reference 47). Residual stresses are induced during any forming operation. Tube alloys susceptible to stress corrosion cracking should be annealed after their manufacture. Residual stresses also result from dents due to rough treatment of tubes.

The stress corrosion performance of some tube alloys is reported in Table IV.G.4. (Data from References 47 and 49). Titanium, stainless steel, 70-30 Cu Ni, and 90-10 Cu Ni, are essentially immune to stress corrosion cracking in ammonia, while aluminum brass and admiralty are highly susceptible.

3. Recommendations

a. EPRI Sponsored Research

Ammonia corrosion and stress corrosion cracking tube failures in the air removal section account for a significant fraction of condenser water in-leakage incidents. The factors which influence the attack appear to have been adequately characterized. Experimental work has identified the susceptibility of various tube materials to attack and demonstrated that there are tube materials available which will nearly eliminate the incidence of ammonia corrosion and stress corrosion cracking. EPRI sponsored research in this area does not appear to be necessary.

b. Equipment Specification Requirements

To minimize the incidence of ammonia corrosion and stress corrosion cracking, it is recommended that the tube material used in the air removal section be highly resistant to ammonia corrosion and stress corrosion cracking. Possible candidate tube materials are titanium, stainless steel, and 70-30 Cu Ni.

c. Operating or Maintenance Procedures

The rate of ammonia corrosion and stress corrosion cracking can be retarded by reducing the concentrations of oxygen and carbon dioxide in the air removal section. It is recommended that procedures to locate and limit air in-leakage to the condenser be developed to control the concentrations of these noncondensable gases.

TABLE 4.G-1

Bechtel Survey: Fraction of Units Reporting Corrosion in Air Removal Section for Various Tube Materials

Air Removal Section Tube Material	Number In Survey	Number Reporting Corrosion	Fraction
Admiralty	51	33	0.65
Aluminum Brass or Bronze	41	19	0.46
70-30 CuNi	53	4	0.08
90-10 CuNi	67	10	0.15
Stainless Steel	110	5 (1)	0.05 (1)
Titanium	24	0	0.0
TOTAL	346	72	0.21

Note: (1) The Bechtel field survey results do not differentiate between ID and OD attack. The cooling water for the 3 stainless steel tubesets reporting stress corrosion cracking was from a cooling tower. The cooling water for the stainless steel tubesets reporting chemical attack or general corrosion was brackish water. It is considered unlikely that stainless steel experienced general corrosion, chemical attack or stress corrosion cracking on the OD in a steam side air cooler environment.

TABLE 4.G-2

HEI Survey: Fraction of Units Reporting Corrosion in Air Removal Section for Various Tube Materials

Air Removal Section Tube Material	Number In Survey	Number Reporting Corrosion	Fraction
Admiralty	165	38	0.23
Aluminum Brass or Bronze	39	10	0.26
Arsenical Copper	33	5	0.15
70-30 CuNi	53	3	0.06
90-10 CuNi	41	0	0.0
Stainless Steel	172	2 (1)	0.0 (1)
Titanium	13	0	0.0
TOTAL	516	58	0.11

Note: (1) Two stations with stainless steel air cooler sections reported leaks in the air cooler section. No differentiation between OD and ID.

TABLE 4.G-3

Relative Rating of Condenser Tube Materials for Resistance to Ammonia Corrosion*

Rating	Alloy
Essentially Immune	Titanium, 304 and 316 Stainless Steel
Highly Resistant	70-30 CuNi, 90-10 CuNi
Moderately Resistant	Arsenical Aluminum Brass
Least Resistant	Iron Phosphorus Deoxidized Copper, Arsenical Copper, Aluminum Brass, Admiralty

*Adapted from Reference 47

TABLE 4.G-4

Stress Corrosion Performance of Tube Alloys
in an Ammoniacal Environment*

Rating	Alloy
Essentially Immune	Titanium, Stainless Steel, Arsenical Phosphorus Deoxidized Copper, Iron Phosphorus Deoxidized Copper, 70-30 CuNi, 90-10 CuNi (Iron Solutionized)
Moderately Susceptible	90-10 CuNi (Iron Precipitated), Aluminum Bronze
Highly Susceptible	Arsenical Aluminum Brass, Admiralty, Inhibited Admiralty

*Adapted from References 47 and 49

H. Tube to Tubesheet Joints

Tube to tubesheet joints are subjected to stresses which result from the thermal and hydrostatic forces that exist in condensers. Loss of integrity at the tube to tubesheet seal results in cooling water in-leakage to the condenser and contamination of the condensate. A major problem with tube to tubesheet leaks is that the leaks can be difficult to locate. Tube to tubesheet leaks that are difficult to locate can be of sufficient magnitude to upset the control of feedwater chemistry and have a significant impact on boiler water or feedwater purity.

1. Operating Experience

Information summarized in Nuclear Power Experience indicates that tube to tubesheet problems are being experienced at the Connecticut Yankee, Indian Point 2, Surry 1 and 2, Millstone 1, and the Brunswick 1 and 2 nuclear power plants. Tube to tubesheet problems reported by these plants are summarized in Table IV.H.1. Of the seven plants in the table, only the Brunswick 1 and 2 plants have had recurring problems. It appears that at other plants reexpansion of the tubes into the tubesheet was successful.

Results from the HEI survey (see Appendix B) indicate that 109 of the 527 units surveyed, about 21%, report some tube to tubesheet joint leakage. On the other hand, a survey conducted by Bechtel for EPRI (Reference 14) indicates that leakage at the tube to tubesheet joint was one of the three major leakage problems in only 3% of the tubesets. It is possible that tube to tubesheet leakage was experienced at some installations covered by the Bechtel survey and that the leakage was not reported by the installations as one of their three major causes of condenser leakage.

Table IV.H.2 summarizes results from the HEI study with respect to tube to tubesheet leaks for various combinations of tubesheet and tubeset materials. Units with a Muntz metal tubesheet and stainless steel tubes had the highest rate of problems, with 74% reporting leakage at the tube to tubesheet joint. No tube to tubesheet leakage was reported for units with stainless steel tubesheets and tubesets.

Table IV.H.3 summarizes the tube to tubesheet leakage incidents from the Bechtel survey for various combinations of tubeset and tubesheet materials. Of the thirteen different combinations, only the admiralty tubeset-carbon steel tubesheet and the 304 stainless steel tubeset-carbon steel tubesheet combinations had significant percentages of the units surveyed report tube to tubesheet leakage. This may reflect corrosion of the carbon steel tubesheet.

2. Evaluation and Discussion

a. Causes of Tube to Tubesheet Joint Failure

Axial loads on the tube to tubesheet joint can occur from deformation of the tubesheet under hydrostatic loads or differential thermal expansion of the condenser shell and tubes. Hydrostatic pressure in the waterbox in present day condensers that operate with cooling towers can be as high as 150 psig. The pressure causes the tubesheet to deform, placing the tubes at the center of the bundle in compression and placing tubes at the periphery of the bundle in tension. Results of an analytical model and of strain gage tests, presented in Reference 17, show that the most highly stressed tubes are in tension at the periphery of the tube bundle.

Differential thermal expansion can occur between the condenser shell and the tubes because the shell and the tubes are at different temperatures and because they have different coefficients of thermal expansion. This differential thermal expansion is accommodated under normal operating conditions by expansion joints (see Reference 37). The stress may become large, however, under abnormal operating conditions, for example, with one tube bundle out of service in a condenser having several tube bundles.

b. Rolled Tube to Tubesheet Joint

The majority of tube to tubesheet joints are formed by rolling, as demonstrated by the Bechtel survey, in which at least 81% of the units employed joints that were rolled. Possible rolled joint types are:

- Rolled and extended
- Rolled and flared
- Rolled, grooved and flared

In comparing the pullout strength of the first two joint types, Reference 37 indicates that tube inlet flaring will add to joint strength under tensile load conditions, but that the amount of increase is difficult to quantify.

Appendix A of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, presents an equation for determining maximum allowable loads on a tube to tubesheet joints. The maximum allowable load is directly proportional to f_r, a factor which accounts for the type joint under consideration. Some values of f_r for grooved and ungrooved tube holes are presented below. The values demonstrate that grooved tube holes have greater pullout strength than ungrooved tube holes.

Description	f_r
Rolled, two or more grooves	.70
Rolled, single groove	.65
Rolled, no grooves	.50

The mechanical pullout strength developed by a particular rolled joint does not necessarily reflect the capability of the joint to provide a seal between the condensate and the cooling water. Coit, in Reference 38, reports that a series of tests were conducted to determine leak tightness for stainless steel tubes in carbon steel tubesheets with holes that were grooved or ungrooved, and plain or prerolled. It was found that smooth prerolled tubeholes were best for high pressure leak tightness, and that grooved holes developed the greatest pullout strength.

The surface roughness of the tubesheet hole affects the seal strength and pullout strength of tube to tubesheet joints. Experimental results from Nishio et al (Reference 63) indicate that improving the smoothness of the tubesheet hole increased the degree of leak tightness. Further experimental results by Nishio et. al. confirm that the highest integrity tube to tubesheet joints utilize seal welding of the tubes to the tubesheet.

In selecting materials for the tubeset and tubesheet, consideration should be given to the relative yield strength of the two materials. It is desirable to have a tubeset material which has a yield strength less than the yield strength of the tubesheet. In Appendix A of the ASME Boiler and Pressure Vessel Code (Reference 39), the maximum allowable tube to tubesheet joint loading is directly proportional to the quantity f_y, defined as follows:

$$fy = \begin{cases} 1.0 & S_{TS} > S_T \\ \dfrac{S_{TS}}{S_T} & \text{Otherwise} \end{cases}$$

where S_{TS} = yield strength of tubesheet material

S_T = yield strength of tube material

In selecting a tube material, the work hardening characteristics should be considered. When a tube material is susceptible to work hardening, it can be more difficult to achieve a satisfactory seal if rerolling of the joint becomes necessary.

An important factor in determining the integrity of tube to tubesheet joints in a condenser is quality control of the rolling process to assure joint uniformity. Before rolling the condenser tubes, the rolling process and equipment should be qualified in a tube to tubesheet mock-up which is destructively examined. During the rolling operation the percent wall reduction and the rolling equipment should be periodically checked to assure that the required tube to tubesheet joint is being obtained.

c. <u>Welded Tube to Tubesheet Joint</u>

A welded joint has advantages over a rolled joint in that it develops greater pullout strength and provides a more positive leak-tight joint. Wilson and Edens, in Reference 40, state that a tube welded to the tubesheet will exhibit a joint strength about 50% greater than a rolled tube.

The ASME Code (Reference 39), in their treatment of joint strength, indicate that a welded joint can be 60% stronger than a joint that is rolled, if the weld dimensions satisfy certain criteria.

Tube and tubesheet materials preferable for welded joints are the carbon steels, stainless steels, and copper nickel. On the other hand, the materials which are predominantly copper (for example, admiralty and arsenical copper) are difficult to weld. If titanium tubing is used with a welded joint, the tubesheet should be titanium or titanium clad. With respect to titanium welds, Peake et al, in Reference 16, comment that welding titanium is a demanding process that has been successfully performed in the shop, but that the clean environment required may be difficult to obtain in the field.

d. Double Tubesheet

The double tubesheet prevents contamination of the condensate with cooling water by providing an intervening space. This space can be provided with a drain to indicate leakage from the seawater side, or alternately, can be pressurized with water of condensate purity. If the latter option is used and a break in the seal at a tube to tube-sheet joint occurs, the high purity, pressurized water will be forced through the leak. Regardless of the leak direction, to the shell side of the condenser or to the waterbox, the purity of the boiler water or feedwater will be preserved.

The double tubesheet can take several different forms, as shown in Figure IV.H.1. Inset a) shows a conventional type of double tubesheet. The double tubesheet depicted in inset b) is an alternate configuration which reduces the amount of tube surface area which is not available for heat transfer. However, this design can subject the tubes to high shear loads from differential thermal expansion of the two tubesheets. Inset c) shows the integral, grooved double tubesheet which incorporates the concept of a double tubesheet into a single plate. The major difficulty with this design appears to be in machining the integral grooves. This geometry has been utilized in a few condenser installations.

3. Recommendations

a. EPRI Sponsored Support

It is recommended that support be provided for work in the following areas:

- Development of a standard sensitive leak location procedure for application to leaks which occur at the tube to tubesheet joint. Candidate procedures should be field tested on condensers which are experiencing tube to tubesheet leaks.
- Establish a program to follow experience with a condenser having double tubesheets for the purpose of verifying that double tubesheets can eliminate feedwater contamination by tube to tubesheet leakage.

b. Equipment Specification Requirements

To minimize the incidence of condensate contamination due to tube to tubesheet leaks, it is recommended that the following requirements be incorporated into condenser equipment specifications:

1) A double tubesheet design shall be used. The design shall be submitted to the Purchaser for approval. Fabrication of the condenser shall not commence until the Purchaser has approved the double tubesheet design.

2) An analysis shall be performed to determine loads on tube to tubesheet joints. The loads shall not exceed the maximum allowable, as specified in Appendix A of the ASME Boiler and Pressuve Vessel Code, Section VIII, Division 1. Fabrication of the condenser shall not commence until the Purchaser has approved the analysis of the tube to tubesheet joints.

3) The tube to tubesheet joint forming process and the joint forming equipment shall be qualified on a tubesheet mock-up. To assure that the required joint strength and leak tightness is obtained, the tubesheet mock-up shall be destructively examined. Results from the joint forming process and equipment qualification, and results from the destructive examination of the tubesheet mock-up shall be submitted to the Purchaser for review.

4) The tube to tubesheet joint forming process shall be performed in accordance with a formal quality control program. The written quality control program shall be submitted to the Purchaser for review.

c. Operating or Maintenance Procedures

A procedure should be developed and the necessary equipment obtained to locate suspected condenser leaks, including those at tube to tubesheet joints. See Section IV.B for further discussion on location of tube to tubesheet leaks.

TABLE 4.H-1

Summary of Nuclear Power Experience Reports for Condensers Experiencing Tube to Tubesheet Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Leaks	Tubes Rerolled	Tube To Tubesheet	Tubes Plugged
Connecticut Yankee	PWR	June 1972	Leakage because of 30 improperly rolled tubes.	X	X	X	
		June 1975	Leakage at tube-tubesheet joints. Thirty-five tubes rerolled.	X	X	X	
Indian Point 2	PWR	May 1975	One tube rerolled.	X	X	X	
Surry 1 and 2	PWR	January 1977	Defects in tube to tubesheet roll; approximately 304 tubes.	X		X	X
Millstone 1	BWR	July 1972	Metal grill breaks away and lodges against tubesheet. Leaking tubes rerolled and plugged.	X	X	X	X
Brunswick 1 and 2	BWR	Fall 1977	Epoxy applied to tubesheet to seal potential tube to tube-sheet leaks.			X	
		February 1978	Use of integrally grooved tube-sheet under consideration.			X	

TABLE 4.H-1 (Continued)

Summary of Nuclear Power Experience Reports for Condensers Experiencing Tube to Tubesheet Problems

Unit	Type	Date	Problem Description	Problem Category: Tube Leaks	Problem Category: Tubes Rerolled	Problem Category: Tube To Tubesheet	Problem Category: Tubes Plugged
Brunswick 1 and 2 (continued)	BWR	September 1978	Several tubes protrude from tubesheet. Tubes are re-rolled.		X	X	
		January 1979	Four tubes protrude from tubesheet. Tubes are re-rolled.		X	X	

TABLE 4.H-2

HEI Survey:
Fraction Reporting Problems for
Various Tubeset and Tubesheet Combinations

Tubesheet Material	Tubeset Material	Number Reporting Tube to Tubesheet Leaks'	Total Tubesets	Fraction Reporting Leaks
Muntz	Admiralty	37	170	0.22
Carbon Steel	Admiralty	8	22	0.36
Muntz	Arsenical Copper	1	19	0.05
Muntz	Stainless Steel	17	23	0.74
Carbon Steel	Stainless Steel	6	37	0.16
Stainless Steel	Stainless Steel	0	9	0.00
Muntz	Aluminum Brass	8	32	0.25
Muntz	90-10 CuNi	6	29	0.21

TABLE 4.H-3

Bechtel Survey:
Fraction Reporting Problems for
Various Tubeset and Tubesheet Combinations

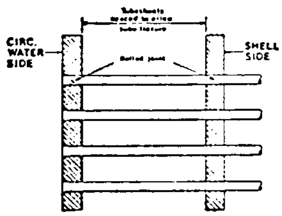
PAGE 1 OF 2

Tubesheet Material	Tubeset Material	Number Reporting Tube to Tubesheet Leaks	Total Tubesets	Fraction Reporting Leaks
Muntz	Admiralty	0	120	0
Carbon Steel	Admiralty	4	17	.24
Silicon Bronze	Admiralty	0	12	0
Muntz	Aluminum Brass	0	52	0
Muntz	90-10 CuNi	6	89	.07
Muntz	70-30 CuNi	0	55	0
Silicon Bronze	70-30 CuNi	0	14	0
Muntz	Titanium	0	23	0
Carbon Steel	304 Stainless Steel	8	35	.23
304 Stainless Steel	304 Stainless Steel	0	10	0
Muntz	304 Stainless Steel	0	96	0

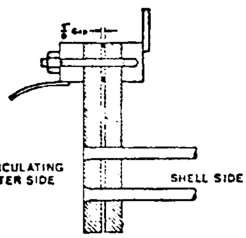
TABLE 4.H-3 (Continued)

Bechtel Survey:
Fraction Reporting Problems for
Various Tubeset and Tubesheet Combinations

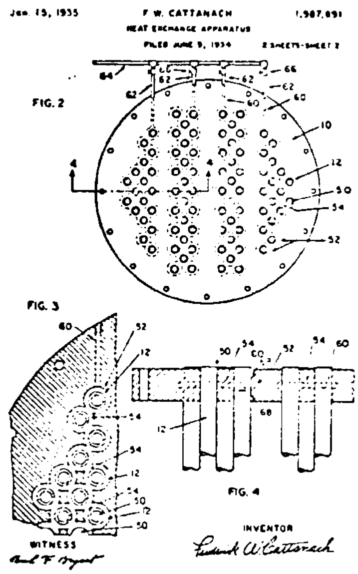
Tubesheet Material	Tubeset Material	Number Reporting Tube to Tubesheet Leaks'	Total Tubesets	Fraction Reporting Leaks
Muntz	316 Stainless Steel	0	34	0
Aluminum Bronze	Aluminum Bronze	0	12	0



a) Conventional Double Tubesheet*



b) Pinned Double Tubesheet *



C) Integral, Grooved Double Tubesheet**

Figure 4.H-1. Double Tubesheets

* Figure adapted from Peake et al, Reference 16

** Cattanach, F. W., Patent No. 1,987,891, "Heat Exchange Apparatus," January 15, 1935.

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VI. APPENDICES

APPENDIX A

SUMMARY REPORT
OF
UNIT SHUTDOWNS OR POWER REDUCTIONS ATTRIBUTED TO CONDENSERS

SUMMARY SHEET
OF
UNIT SHUTDOWNS OR POWER REDUCTIONS ATTRIBUTED TO CONDENSERS

JUNE 1978 THROUGH MAY 1979

UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Arkansas 2	12-23-78	F	68.9	A	Condenser tube leak
Beaver Valley 1	6-26-78	F	4.9	A	Inability to maintain condenser vacuum with air in the circulating system.
Browns Ferry 3	8-22-78	F	6.8	A	Low condenser vacuum due to a faulty test switch
	8-24-78	F	4.8	A	Condenser low vacuum (corroded strips in a junction box prevented pressure signals from reaching the EHC system)
Brunswick 1	9-08-78	F	23.5	A	Power was reduced to remove "B" South waterbox from service. This was necessary to clean the condenser, locate leaks, and make repairs. Several tubes were found to be protruding through the tube sheet. These tubes were rerolled and the condenser "B" South returned to service. There is a continuing leak in the "B" South condenser.
	9-10-78	F	12.6	A	Power was decreased to remove "B" South waterbox from service. This was necessary to locate leaks and repair leaking tubes and tube sheet. Five tubes were plugged and the condenser was returned to service with a leak remaining.
	9-15-78	S	80.5	A	Reduced reactor power to remove "B" South waterbox from service and perform tube leak checks.
	5-16-79	F	8.6	B	Power reduced to remove "A" north waterbox due to conductivity problems 1A north condenser waterbox was entered and one tube leak was found. Both ends of tube were plugged. All tubes were checked for protusions or looseness in tubesheet.
Brunswick 2	9-6-78	S	423.0	A	Separated from grid and manually scrammed the reactor because of high condensate conductivity. The high conductivity in the condensate system was caused by the following: approximately nine extraction line expansion joints inside the condenser failed. This failure caused the

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Brunswick 2 (Continued)					1/4" steel penthouse around these expansion joints to deform the and break apart. The metal from the penthouse fell on top of the condenser tube and caused them to start leaking.
	10-7-78	F	0.	B	Reduced Reactor Power to approximately 80% for MSIV periodic test and waterbox 2A-north and 2A-south cleaning. Returned to 100% power.
	1-27-79	F	14.5	B	Power was reduced to remove condenser waterbox 2B-N from service to investigate and repair leaks. Corrective action: 2B-N condenser leak checked. 4 tubes were protruding out the tubesheet, these were rerolled. 3 tubes were plugged that indicated leaks.
Cook 1	7-14-78	F	12.4	H	Unit trip due to low condenser vacuum. Vacuum was lost when the steam generator blowdown to the normal tank was isolated. The start-up blowdown tank discharge valve was found 1 1/2 turn open providing a flow path from the condenser to atmosphere. Power increased to 99%. Power was increased to 100% on 7-19-78 for the first time on Cycle 3.
	4-6-79	S	590.2	C	The unit was scheduled to be removed from service after peak on 4/6/79. The unit tripped the same day due to loss of both main feed pump turbines caused by F. P. T. condenser vacuum. The low vacuum condition was created by lake debris plugging up the condenser tubesheets. The unit then begin the refueling outage.
Cook 2	6-9-78	F	8.1	H	Turbine/Reactor trip due to an apparent low vacuum in "B" condenser.
	6-16-78	F	5.9	H	Turbine/Reactor trip from 72% power due to an apparent low condenser vacuum.
	6-17-78	F	6.7	H	Turbine/Reactor trip from 80% power due to an apparent low condenser vacuum.
	6-19-78	F	91.5	H	Turbine/Reactor trip due to apparent low vacuum in "A" condenser. The

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Cook 2 (Continued)					low vacuum trips experienced were found to be due to an impulse pressure effect on the low vacuum trip devices from an alternate drain line from L.P. Heater 4A which discharged in the immediate vicinity of the condenser vacuum sensing lines.
	8-21-78	F	32.8	G	Unit trip. Trip due to low condenser vacuum.
	8-27-78	F	148.8	H	Unit Trip. Trip caused by low vacuum trip device on "B" condenser. No apparent reason for trip, condenser vacuum normal when rolling turbine during trip recovery the turbine tripped. Investigation revealed bearing and gear failures in front standard. Unit was shut down for repairs and remained out of service at the end of the month.
	1-2-79	F	0.	A	Reactor Power reduced to 50% to remove last main f-P turbine from service to repair leaks in the f-p turbine condenser. Reactor power returned to 100% on 1-3-79.
	1-13-79	F	8.6	A	Unit trip due to drop in "A" condenser vacuum caused by multiple tube failures.
	4-6-79	F	*	H	Reactor power reduced to 55% to permit removal from service of one main feed pump turbine condenser at a time for cleaning of condenser waterboxes. Reactor power returned to 100% the same day.
Crystal River	11-17-78	S	0.	B	Power reduced to 50% for about 16 hours to clean main condensers and perform feedwater booster pump maintenance.
	12-6-78	S	*	B	Power reduced to 80% to clean main condensers.
Fort Calhoun	2-10-79	F	*	A	Power reduced to appr. 70% for suspected condenser tube leakage.
Indian Point 2	2-28-79	F	2.3	A	No 22 hi level.
	4-23-79	F	20.6	A	Malfunction of condenser steam-dump system.

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Kewaunee	10-15-78	S	0.	B	L.R. to 60% to allow inspection and repair of condenser circulating water tubes.
Maine Yankee	6-04-78	F	20.6	A	L.R. to 72%. Condenser tube leak in the "B" waterbox tube plugged.
	6-07-78	F	27.8	A	L.R. to 74%. Condenser tube leak in the "A" waterbox tube plugged.
	6-09-78	F	102.0	A	L.R. to 73%. Condenser leak in the "A" waterbox tube plugged.
	6-18-78	F	11.3	A	L.R. to 74%. Condenser tube leak in the "C" waterbox tube plugged.
	11-12-78	F	19.50	A	L.R. to 80%. Condenser tube leak in the "A" waterbox tube plugged.
	11-27-78- 11-28-78	F	9.83	A	L.R. to 80%. Condenser tube leak in the ""B" waterbox - tube plugged.
	12-04-78	F	7.8	A	L.R. to 80%. Condenser tube leak in the "D" waterbox tube plugged.
	12-05-78	F	7.4	A	L.R. to 80%. Condenser tube leak in the "B" waterbox tube plugged.
	12-11-78	F	12.0	A	L.R. to 80%. Condenser tube leak in the "B" waterbox 2 tubes plugged.
	12-14-78	F	30.0	A	L.R. to 80%. Condenser tube leak in the "B" waterbox 4 tubes plugged.
	12-20-78	F	10.2	A	L.R. to 80%. Condenser tube leaks in the "A" and "B" waterboxes 2 tubes plugged.
	12-23-78	F	8.4	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	12-28-78	F	6.7	A	L.R. to 80%. Condenser tube leak in the "B" waterbox 1 tube plugged.
	12-31-78	F	7.0	A	L.R. to 80%. Condenser tube leaks in the "D" waterbox 5 tubes plugged.
	1-06-79 1-07-79	S	29.5	B	L.R. to 75%. ECT of selected condenser waterbox tubes.
	1-08-79	F	11.4	A	L.R. to 80%. Condenser tube leaks in the "C" & "D" waterboxes. Plugged 1 tube in each.
	1-11-79	F	7.2	A	L.R. to 80%. Condenser tube leak in the "A" waterbox tube plugged.

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Maine Yankee (continued)	1-14-79	F	7.2	A	L.R. to 80%. Condenser tube leaks in the "D" waterbox. 3 tubes plugged.
	1-17-79	F	12.0	A	L.R. to 80%. Condenser tube leaks in the "D" waterbox 1 tube plugged.
	1-18-79	F	10.2	A	L.R. to 80%. Apparent tube leak in the "D" waterbox no leak could be found.
	1-19-79	F	7.7	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	1-20-79	F	7.5	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 3 tubes plugged.
	1-27-79	F	8.4	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	1-29-79	F	5.5	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	1-30-79	F	10.0	A	L.R. to 80%. Condenser tube leak in the "A" waterbox 1 tube plugged.
	1-31-79	F	9.9	A	L.R. to 80%. Condenser tube leak in the "A" waterbox 1 tube plugged.
	2-03-79	F	8.3	A	L.R. to 80%. Condenser tube leak in the "A" waterbox tube plugged.
	2-07-79	F	13.1	A	L.R. to 80%. Condenser tube leak in the "A" waterbox 2 tubes plugged.
	2-14-79 2-15-79	F	15.9	A	L.R. to 80%. Condenser tube leaks in the "A" and "D" waterboxes 3 tubes plugged.
	2-19-79	F	10.2	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	2-21-79 2-22-79	F F	8.0	A	L.R. to 80%. Condenser tube leak in the "B" waterbox 1 tube plugged.
	2-22-79	F	7.3	A	L.R. to 80%. Condenser tube leak in the "D" waterbox 1 tube plugged.
	2-24-79 3-5-79	S	216.6	B	L.R. to 75%. Eddy current testing of all condenser tubes.
	3-8-79 3-12-79	S	87.7	B	L.R. to 80%. Eddy current testing of the "A" waterbox condenser tube.
Millstone 1	7-03-78	F	o	A	Reduced power to appr. 80% to plug leaking main condenser tubes. After repairs were made, unit power was increased.

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Millstone 1 (continued)	7-25-78	F	0	A	Reduced power to appr. 80% plug leaking main condenser tubes. After repair, unit power was increased.
	7-26-78	F	0	A	Reduced power to appr. 80% to plug leaking main condenser tubes. After repair, unit power was incresed.
	7-26-78	F	0	A	Reduced power to appr. 80% plug leaking main condenser tubes. After repair, unit was increased.
	7-29-78	F	0	A	Reduced power to appr. 85% plug leaking main condenser tubes. After repair, unit power was increased.
	8-18-78	F	0	A	Reduced power to plug leaking main condenser tubes. Power was increased.
	8-28-78	F	0	A	Reduced power to appr. 30% plug leaking main condenser tubes and to install condenser tube inserts. After repairs were completed power was increased.
	9-4-78	F	0.	A	Reduced power to appr. 60% for main condenser maintenance and cleaning of turbine building closed cooling water heat exchangers. Following maintenance unit power was increased.
	10-19-78	S	0	B	Reduced power to appr. 70% for main condenser maintenance and control rod pattern adjustment. Power was increased following maintenance.
	12-25-78	F	0	B	Reduced power to appr. 75% for main condenser maintenance and control rod pattern adjustment. Power was increased following maintenance.
	1-22-79	S	N/A	B	Reduced power to appr. 75% for main condenser maintenance. Power was increased following maintenance.
	3-10-79	F	N/A	B/H	Reduced unit power to appr. 70% main condenser delta-T reasons and main condenser maintenance.
Millstone 2	7-23-78	S	0	B	Reduced Power to appr. 80% to clean the main condensers.
Oconee 1	11-21-78	F	*	H	Power reduced to 95% due to low condenser vacuum.

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UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Oconee 2	4-6-79	F	0.	A	Power reduced to appr. 85% due to 2A1 condenser tube leak.
	4-19-79	F	*	A	Power reduced to appr. 90%, further checking for condenser tube leak.
	4-25-79	F	*	A	Power reduced to appr. 80% 2A1 condenser tube leak.
	5-11-79	F	139.3	A	Condenser tube leak.
Pilgrim 1	6-4-78	S	0.	B	Power reduced to 70% for condenser cleaning and anode replacement.
	6-11-78	S	0.	B	Power reduced to 60% for condenser cleaning and anode replacement.
	7-2-78	S	0.	B	Load reduction to 80% to backwash main condenser and inspect B the pump and intake tunnel.
	7-8-78	S	0.	B	L.R. to 50% to apply epoxy coating to condenser inlet tube sheets.
	3-4-78	S	0.	B	L.R. to 70% for main condenser backwash, repair steam leaks and individual CRD scram times.
Point Beach 2	7-22-78	S	8.0	B	Load reduced to 150 MWe (Design Electrical Rating = 497 MWe) for 8 hours to locate and plug a slightly leaking condenser tube.
Praire Island 1	12-4-78	S	0.	B	Reduced power to 40% to clean one of the two main condensers.
	12-5-78	S	0.	B	Reduced power to 40% to clean the other main condenser.
Quad Cities 1	8-13-78	S	N/A	H	Electrical load was reduced to 483 MWe to reverse main condenser circulating water flow (Designed Electrical Rating = 789 MWe).
	8-20-78	S	N/A	H	Electrical Load was reduced to 450 MWe for condenser flow reversal.
	8-27-78	S	N/A	H	Load was reduced to 458 MWe for condenser flow reversal.

ABBREVATIONS

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REASON
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C-REFUELING
D-REGULATORY RESTRICTION
E-OPERATOR TRAINING
F-ADMINISTRATIVE
G-OPERATIONAL ERROR
H-OTHER

PROBLEM
M-MULTIPLE

*DURATION NOT SPECIFIED ARE MARKED WITH AN ASTERISK

SUMMARY SHEET
OF
UNIT SHUTDOWNS OR POWER REDUCTIONS ATTRIBUTED TO CONDENSERS

JUNE 1978 THROUGH MAY 1979

UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Quad Cities 1	9-2-78	S	N/A	N/A	Load was reduced to appr. 50% for condenser flow reversal.
	10-08-78	S	N/A	N/A	Load was reduced to appr. 60% for condenser flow reversal.
	10-09-78	S	N/A	N/A	Load was reduced to appr. 60% for condenser flow reversal.
	10-15-78	S	N/A	N/A	Load was reduced to appr. 50% for MSIV biweekly surveillance and condenser flow reversal.
	10-24-78	S	N/A	N/A	Load was reduced to appr. 50% for condenser flow reversal.
	11-26-78	S	*	N/A	Load reduced to appr. 50% for condenser flow reversal.
	4-7-79	F	0	F	Load was reduced to 80% for condenser flow reversal.
Quad Cities 2	10-14-78	S	N/A	N/A	L.R. to appr. 60% for condenser flow reversal.
	2-18-79	F	*	H	L.R. to appr. 60% for condenser flow reversal.
	3-24-79	S	*	H	L.R. to appr. 40% for main condenser flow reversal.
	7-1-78	S	N/A	B	L.R. to appr. 75%; No. 2 waterbox taken out of service to inspect condenser tubes.
	8-20-78	S	*	B	Power reduction to appr. 75% to inspect condensers for possible tube leaks.
	9-9-78	S	0.	B	L.R. to appr. 75% inspection of condenser.
	9-16-78	S	0.	B	L.R. to appr. 75% inspection of condenser tubes.
	12-16-78	S	*	B	Power reduced to appr. 65% inspection and plugging of condenser leaking tubes.
	1-5-79	S	*	B	Inspect condenser waterboxes for leaking tubes, negligible load reduction.
	3-19-79	S	*	B	Load reduction to appr. 90% condenser tube inspection.

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SUMMARY SHEET
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JUNE 1978 THROUGH MAY 1979

UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Salem 1	6-16-78	F	30.0	A	Condenser tube leak.
	8-15-78	F	0.	A	L.R. to appr. 90% 12A condenser leak.
	8-24-78	F	0.	A	L.R. to appr. 90% 11A condenser leak.
	8-25-78	F	0.	A	L.R. to appr. 90% 12A condenser leak.
	10-3-78	F	0.	A	11b condenser tube leak; no L.R.
	10-11-78	F	111.6	A	11A and 11B condenser tube leak and secondary chemistry problems.
	1-29-79 1-30-79	F	0.0	A	L.R. to 75% 13B condenser pump. cleaned tubesheet.
	2-27-79 2-28-79	F	0.0	A	L.R. to 75% 13A condensers, cleaned tubesheet.
	3-6-79 3-10-79	F	0.0	A	L.R. to 70% 13B condensers, cleaned waterbox
	3-19-79 3-20-79	F	0.0	A	L.R. to 80% 13B condensers, cleaned waterbox.
San Onofre 1	6-9-78	S	0.	B,F	Load reduced to 55% for condenser tube plugging, maintained reduction to defer fuel depletion.
	8-30-78	S	0.	B	Load reduced to 70% for condenser cleaning.
	2-21-79	S	6.5	B	Clean condenser waterboxes and perform quarterly test of reactor coolant system flow-channel-manual load reduction.
	2-23-79	F	6.8	A	Inspect condenser for tube leak and plug leaking tubes-manual load reduction.
St. Lucie 1	6-24-78	S	16.2	B	Unit was removed from service for maintenance work on circulating water system. cleaning condensers and miscellaneous maintenance.
Three Mile Island 2	1-9-79	F	0.0	A	Decreased power to 60% to try to locate/repair condenser leaks.

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SUMMARY SHEET
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UNIT SHUTDOWNS OR POWER REDUCTIONS ATTRIBUTED TO CONDENSERS

JUNE 1978 THROUGH MAY 1979

UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Turkey Point 3	6-13-78	F	0.	A	Load reduced to appr. 50% to locate and repair condenser tube leaks (non-nuclear system).
	7-7-78	F	24.1	A	Unit was removed from service to locate and repair condenser tube leak. (non-nuclear system)
	7-10-78	F	0.	A	Load Reduction to 70% to locate and repair condenser tube leaks (non-nuclear system)
	7-18-78	F	0.	A	Load Reduction to 70% to locate and repair condenser tube leaks (non-nuclear system)
	7-30-78	F	0.	A	Load Reduction to 55% to locate and repair condenser tube leaks (non-nuclear system)
	9-22-78	F	0.	A	Load Reduction to 70% to locate and repair condenser tube leaks (non-nuclear system)
	9-23-78	F	0.	A	L.R. to 40% to locate & repair condenser tube leaks (non-nuclear system).
	10-18-78	F	0.	A	L.R. to 50% to locate & repair condenser tube leaks (non-nuclear system)
	11-27-78	F	0.	A	L.R. to locate & repair condenser tube leaks (non-nuclear system), unknown L.R. due to condenser becaus of multiple problems.
	11-28-78	F	0.	A	Unit was operated at appr. 50% R.P. to repair condenser tube leak.
	12-6-78	F	0.	A	Load reduction to repair condenser tube leak (non-nuclear systeam). Unknown L.R. due to condenser because of multiple problems.
Turkey Point 4	10-2-78	S	61.4	B	Unit was removed from service to test turbine overspeed trip device. The outage was extended to repair condenser tube leaks (non-nuclear system).
	10-5-78	S	7.3	A	Repair condenser tube leak (non-nuclear system).

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SUMMARY SHEET
OF
UNIT SHUTDOWNS OR POWER REDUCTIONS ATTRIBUTED TO CONDENSERS

JUNE 1978 THROUGH MAY 1979

UNIT	DATE	TYPE	DURATION* (HOURS)	REASON	PROBLEM DESCRIPTION
Turkey Point 4 (continued)	10-9-78	F	0.	N/A	Reduced Power to 60% to repair condenser tube leak (non-nuclear system)
	10-10-78	F	0.	N/A	Reduced Power to 70% to repair condenser tube leak (non-nuclear system).
	12-17-78	F	0.	N/A	L.R. to appr. 30% to repair condenser tube leak (non-nuclear system).

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APPENDIX B

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
1	Louisiana Power & Light	Little Gypsy #3	10	304SS/ 22	304SS/ 22	Carbon Steel 1 1/4					X				30
		Little Gypsy #2	13	Admiralty 18		Carbon Steel 1 1/4"	Specific Information Not Provided								30
		Little Gypsy #1	18	Admiralty		Carbon Steel			X						
		Little Gypsy #4 and #5	8-6	304SS		Carbon Steel 1 1/4"					X			X	
		Water Steam/ Elec	5	304SS/22		Steel 1 3/8"									None
2	Duquesne Light	Shippingport	23	316SS 22		Muntz 1 1/2"	X	X							
		Brunot Island	5	304L 22		Muntz 1 1/4"									None
		Beaver Valley	3	304L 22		304L 7/8"								X	
		Phillips	23	Admiralty 18		Muntz 1 1/2"			X				X		720
		Elrama #1, #2, #3, #4	28 28 25 18	304SS 22		Muntz 1 1/2"	X								
		Cheswick	9	304L 22		304SS 1 1/4"					X				
3	AEP	Cardinal 1	12	Ars Copper 18	70-30 Cu-Ni 18	Silicon bronze 1"			X						472
		Muskingum River #5	10	Ars Copper 19	Ars Copper 19	Silicon bronze 1"			X						747

SUMMARY OF RESULTS OF HEI SURVEY
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CONDENSER PERFORMANCE

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3	AEP (Continu-ed)	Breed Unit 1	18	ARS Copper 18	SS Coated Admiralty 18	Naval Brass 1 1/2"	Location not described								89
4	South Carolina Electric and Gas	Waterce #2	8	304SS 22		Carbon Steel 1 1/8"					X				
		Wateree #1	9	304SS 22		Carbon Steel 1 1/8"					X				
		Canadys #1	17	Admiralty 21		Steel				X (Sand)					
		Canadys #2	15	Aluminum 17 Admiralty 21		Steel				X (Sand)					
		Canadys #3	12	Admiralty		Muntz 1 3/4"				X (Sand)					
		Williams #1	6	304SS 22		Steel 1 1/8"					X				22
		Urquhart #3	24	Admiralty 18		Muntz 1 1/4"	Location not described								25
		McMeekin #1	21	Inhibited Admiralty 18		Muntz 7/8"			X						
		McMeekin #2	21	Inhibited Admiralty 18		Muntz 7/8"	Location not described								

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5	Texas Electric Service Company	Handley 4	3	304SS/22	304SS/20	Carbon Steel 1 1/2								X	
		Handley 3	16	Admiralty/18 304SS		Muntz							X		
		Graham 2	10	Admiralty/18				Locations not described							
		Graham 1	19	Inhibited Admiralty/18				Interior of bundle							
		Morgan Creek 5	20	Admiralty/18	304SS/22	Muntz 1 1/4			X				X		
		Morgan Creek 6	13	Admiralty/18	304SS/22						X (near tubesheet)				
		Morgan Creek 4	25	Arsenical Copper/18		Muntz/12"			X				X		
		Permian Basin 6	7	Admiralty/18	304SS	Muntz/ 1 1/8"									None
		Permian Basin 5	22	Admiralty brass/18		Muntz/ 1 1/4"			X						
		North Main #4	27	Arsenical Cu/ 18		Muntz/ 1 1/4"		Not determined							
		EM 1&2	25 22	Arsenical Admiralty/18		Muntz/ 1 1/4		Not determined							
		EM3	8	Admiralty	SS	Carbon Steel 1 1/4"		Not determined							
		Handley Unit 5	2	304SS		Carbon Steel/ 1 1/2"					X				

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6	Utah Power and Light	Gadsby #3	24	Admiralty		Muntz		Location not described							
		Carbon #2	22	Admiralty/18		Muntz		Location not described							
		Naughton #1	16	Admiralty/18	SS/18	Muntz 1 1/4"		Location not described							
		Naughton #2	11	Arsenical Admiralty/18	SS/18	Muntz-1"		Location not described							
7	Jersey Central Power & Light	Oyster Creek (Orig)	7	Aluminum Bronze		Aluminum Bronze- 1 1/4"	Many leaks - Location not described								
		Oyster Creek (Re-tube)	3	Titanium/22		Aluminum Bronze - 1 1/4"		(None since additional staking in 1977) X							
	Toledo Edison	Davis Besse	2 1/2	304SS/21	304SS/19	Steel-1"		X							
8	Northern Indiana Public Service	D.H.M.S Units 4, 5, & 6	22	Phosphorized Admiralty 18		Muntz 1 1/4"			X	Also along length					
		D.H.M.S Unit 11	8	Admiralty 18	Stainless	Steel 1 1/4"			X	Also along length					
		B.G.S. Unit 7	17	Phosphorized Admiralty		Muntz 1 1/4					X				
		B.G.S. Unit 8	11	Phosphorized Admiralty 18	Stainless 18	Muntz					X				
		Unit 12	5	Admiralty 18	Stainless 27	Muntz - 1 1/8					X				

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No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
9	Northeast Utilities	I	11	Admiralty/18	304SS/22	Muntz- 1 1/4"						X			
		II	3	70-30 Cu Ni/18		Muntz- 1 1/4"				X	(seawater debris)				
		III	10	70-30 Cu Ni/18	70-30 Cu Ni/18	Muntz - 1 1/4"				X	(Also seawater debris)				
10	Public Service Co. of New Mexico		6	Admiralty/18 304SS on exterior/22		Muntz - 1 1/4"	X	(Initial)		Location of later leaks not described.					
11	Southwestern Electric Power		9	Admiralty/18	304SS/20	Muntz - 1 1/4"			Location not described						
			1	90-10 Cu Ni/18	304SS	Muntz - 1 1/4"	X								
			7	Admiralty/18	304SS/20	Muntz 1 1/4"			Location not described						
			15	Admiralty/18	304SS	Muntz-1"	X					X			
			2	Admiralty/18 Exterior is 304SS	304SS	Muntz - 1 1/4"	X	(Initial)						(after start-up)	2
12	Pacific Power & Light	Centralia #1 and #2	8	Admiralty/18	SS	Muntz - 1 1/8"	Few Leaks variable distance from tubesheet.								
		Dave Johnson #4	7	Admiralty/18	SS	Steel - 3/4"	Leaks variable distance from tubesheet								
		Dave Johnson #3	15	Admiralty/18	SS	Muntz - 3/4"	Leaks variable distance from tubesheet								

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No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
12	Pacific Power & Light (Continued)	Dave Johnson #1 and #2	21	Admiralty/18		Muntz -		Operates with minimal leakage							
		Jim Bridger #1, #2, #3	4	Admiralty/18	SS	Muntz 1 1/8"	Leaks variable distance from tubesheet								
13	Portland General Electric		4	Admiralty	70-30 Cu Ni	Muntz - 1 1/4					X				
14	Allegheny Power System	Unit #1 #2 #3	9 8 7	304SS/22		304SS/ 1 1/4"								X	
		Unit #1 #2 #3	7 6 5	304SS/22		Steel Clad with SS-1 1/4"									None
15	Texas Power & Light	Decordova	3	316SS/22		Steel-1"			Pinhole leaks						
		Tradinghouse 1	9	Admiralty/18	316SS	Muntz - 1 1/2"			Pinhole leaks						
		Tradinghouse 2	7	304SS/22		Steel - 1 3/8" and 1 1/8"			Pinhole leaks - Unit being totally retubed						
16	Kansas City Power & Light	Hawthorn 1	28	Admiralty/18		Muntz		Leaks along tube length							
		Hawthorn 2	28	Admiralty/18		Muntz		Leaks along tube length							
		Hawthorn 3	26	Admiralty/18		Muntz		Leaks along tube length							
		Hawthorn 4	24	Admiralty/18		Muntz		Leaks along tube length							
		Hawthorn 5	10	Admiralty/18		Muntz		Leaks along tube length							
		Montrose 1	19	70-30 Cu Ni/18		Steel		Leaks along tube length							

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16	Kansas City Power & Light (continued)	Montrose 2 (retube)	2	90-10 Cu Ni/18		Steel with Cu added		Leaks along tube length							
		Montrose 3	16	Admiralty/18		Muntz		Leaks along tube length							
17	Ohio Edison Company	Burger 3	29	Arsenical Admiralty/18		Muntz-1"		Leaking tubes are plugged without inspection							
		Burger 4	24	Arsenical Admiralty/18											
		Burger 5	24	Antimony Admiralty/18											
		Niles 1	25	Arsenical Admiralty/18											
		Niles 2	25	Plosphorized Admiralty/18											
		W. H. Sammis 1	20	Admiralty/18		Muntz - 1 1/2"		Leaking tubes are plugged without inspection							
		W. H. Sammis 2	19												
		W. H. Sammis 3	18												
		W. H. Sammis 4	17												
		W. H. Sammis 5	12	Arsenical Copper and 70-30 Cu Ni		Muntz - 1 1/8"		Leaking tubes are plugged without inspection							
		W. H. Sammis 6	10												

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18	Hawaiian Electric Company	Waiau 7 (original)	5	Aluminum brass/ 18	Aluminum brass/ 18	Muntz - 1 1/4"	X	(not primarily)					X		
		Waiau 7 (A/C Retube)	7	Aluminum brass/ 18	70-30 Cu Ni/18	Muntz - 1 1/4"	X	(not primarily)						X	
		Waiau 8	10	Aluminum brass/ 18		Muntz - 1 1/4"				X	(Admiralty tubes leaked at inlet and outlet with grooving and pinholes)				
		Kahe 1 (Original)	13	Aluminum brass/ 18	Aluminum brass/ 18	Muntz - 1"				X	(Entrained sand at end of plastic inserts and along bottom of tube length)				
		Kahe 1 (Retube)	3	Titanium/23	Titanium/23	Muntz-1"									None
		Kahe 2 (original)	12	Aluminum brass/ 18	Aluminum brass/ 18	Muntz-1"				X	(Entrained sand at end of plastic inserts and along bottom of tube length)				
		Kahe 2 (Retube)	2	Titanium/23	Titanium/23	Muntz-1"									None
		Kahe 3 (original)	6	Aluminum brass/ 18	Aluminum brass/ 18	Muntz - 1 1/4"			X						
		Kahe 3 (Retube)	2	Aluminum brass/ 18	Titanium/23	Muntz- 1 1/4"			X						
		Kahe 4	7	Aluminum brass/ 18	Aluminum brass/ 18	Muntz -							X		
		Kahe 5 (Original)	3	Aluminum brass/ 18	70-30 Cu Ni/18	Muntz - 1 1/8"				X	(Also erosion throughout length due to entrained sand)				
		Kahe 5 (Retube)	1	Titanium/20	Titanium/20	Muntz - 1 1/8"									None

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19			2	70-30 Cu-Ni/18		304L SS- 1 1/8"	X	(Thought due to shell fish impingement)			X			X (During turbine or condenser repairs)	
20	Gulf States Utilities	Neches #7 (Orig)	4	90-10 Cu Ni/18		Muntz - 1 1/4"			X						
		Neches #7 (Retube)	19	Admiralty Type B/18		Muntz - 1 1/4"			X						
		Neches #8	20	Arsenic inhibited Aluminum bronze/18		Muntz - 1 1/2"			X						
		Sabine #1 (Original	16	90-10 Cu Ni/18		Muntz - 1 1/4"				X					
		Sabine #1 (Retube)	1	Titanium/22		Muntz - 1 1/4"	Experience not described								
		Sabine #2 (Original)	14	90-10 Cu Ni/18		Muntz - 1 1/4"				X					
		Sabine #2 (Retube	2	Titanium/22		Muntz - 1 1/4"	Experience not described								
		Sabine #3 (Original)	10	90-10 Cu Ni/18		Muntz - 1 1/4"				X					
		Sabine #3 (Retube)	2	Titanium/22		Muntz - 1 1/4"	Experience not described								
		Nelson #1	20	Admiralty B/18		Muntz - 1 1/2"									None
		Nelson #2	20	Admiralty B/18		Muntz - 1 1/2"									None

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
20	Gulf States Utilities (Continued)	Nelson #3	19	Admiralty B/18		Muntz - 1 1/4"									None
		Willow Gen #1	19	Admiralty B/18		Muntz - 1 1/4"					X				
		Willow Gen #2	15	Admiralty B/18		Muntz - 1 1/4"			Main body pinhole leaks						
		Willow Gen #3	10	Admiralty B/18	316SS/20	Muntz - 1"		X			X				
21	Montana Power Company	#1 #2	4 3	Inhibited Admiralty with SS in impingement sections/18	SS/20	Muntz - 1 3/8"					X				
22	Southern California Edison	Alamitos #1	21	Aluminum brass/ 18		Muntz - 1 1/2"	X			X					
								(491 tubes replaced with 70-30 and 90-10 Cu Ni due to inlet end erosion)							
		Alamitos #3 and #4	16	Aluminum brass/ 18	70-30 Cu Ni/18	Silicon bronze - 1 1/4"		(Other leaks at various points in tubes)							
		Alamitos #5 and #6	12	90-10 Cu Ni/20	70-30 Cu Ni/20	Muntz - 1 1/8"	X	(Other leaks at various points in tubes)							
		El Segundo #1 (original)	13	Aluminum brass/ 18		Muntz - 1 1/2"		Tube leak locations not determined							
		El Segundo #1 (Retubed)	11	90-10 Cu Ni/20 plus some 316SS		Muntz - 1 1/2"		Tube leak locations not determined Failure of 316SS tubes due to pitting from insufficient flushing during shutdown							300
		El Segundo #2 (Original)	11	Aluminum brass/ 18		Muntz - 1 1/2"		Tube leak locations not determined							
		El Segundo #2 (Retube)	12	90-10 Cu Ni/20		Muntz - 1 1/2"		Tube leak locations not determined							350

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
22	Southern California Edison (continued)	El Segundo #3	15	90-10 Cu Ni/18	70-30 Cu Ni/18	Silicon bronze 1 1/8"			Tube leak locations not determined						127
		El Segundo #4	14	90-10 Cu Ni/18	70-30 Cu Ni/18	Silicon bonze - 1"			Tube leak locations not determined						100
		Etivanda #1 and #2	26	Arsenical Copper/18		Naval brass - 1 1/2"			Tube leak locations not determined						
		Etivanda #3 and #4	16	Arsenical Copper - 75% Inhibited Admiralty - 25%		Silicon bronze 1 1/4"							X		
		Huntington Beach 1-4 (Original)	19 Total	70-30 Cu Ni/18		Silicon bronze 1 3/8"	X (Seldom)			X					
		Huntington Beach 1-4 (Retube)	?	90-10 Cu Ni/18		Silicon bronze 1 3/8"	X (Seldom)			X					
		Mandalay #1 & #2	20	Aluminum brass/ 18		Muntz - 1 1/2"	X (not usually) Leak random throughout length								
		Mohave #1 & #2	8	Admiralty/18	90-10 Cu-Ni/18 (Originally 304SS)	Muntz - 1"		Various locations along length due to severe pitting							
		Ormond Beach #1 #2	8 6	90-10 Cu Ni/20	70-30 Cu Ni/20	Muntz - 1 1/4"		Corrosion cell between tube and tubesheet accelerated by epoxy coating of tubesheet and waterbox Also many leaks 6" into inlet end of tubes due to rough epoxy application inside tubes.							360 220
		Redondo 1-4	30	Aluminum brass/ 18		Muntz - 1 1/4"		Leaks at various locations along the length of the tubes							

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
22	Southern California Edison (Continued)	Redondo 5&6	22/ 24	Aluminum brass/ 18		Muntz - 1 1/2"		Leaks at various locations along the length of the tubes							
		Redondo 7&8	12	90-10 Cu-Ni/20	70-30 Cu Ni/20	Muntz - 1 1/8"		Leaks at various locations along the length of the tubes							
		San Onofre (original)	7	90-10 Cu Ni						X					
		San Onofre (Retube)	5	Titanium/22 50% 90-10 Cu Ni/20 48% 70-30 Cu Ni/20 2%		Steel 5 3/8"	X	(Cu Ni Tubes) X (Titanium tubes)		X					
23	Consumers Power Company	Palisades (Original)	4	Admiralty/18	304SS	Steel-1"		X				X			
		Palisades (Retube)	5	90-10 Cu Ni/20	304SS	Steel-1"		X			X				
		Karn 4	2	90-10 Cu Ni/20		Muntz - 1 3/8"		Leak location not described							1 (start-up)
		Karn 3	4	90-10 Cu Ni/20		Muntz - 1 3/8"		Leak location not described							7

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks								
							Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
24	Mississippi Power Co.	Jack Watson Unit 3	17	Aluminum Brass/ 18 changed to 90-10 Cu-Ni/19		Naval Brass 1 1/4				X					
25	Union Electric Co.	Venice Unit 3	36	Admiralty 18		Muntz - 1 1/2	X								
		Venice Unit 4	31	Admiralty 18		Muntz - 1 1/2	X								
		Venice Unit 5	29	Admiralty 18		Not specified 1 1/2	X								
		Venice Unit 6	29	Admiralty 18		Not specified 1 1/2	X								
		Sioux Unit 1	12	Admiralty 18	Stainless 22	Muntz - 1 1/4	X	X	X						
		Sioux Unit 2	11	Admiralty 18	Stainless	Muntz - 1 1/4	X	X	X						
		Meramec Unit 1	26	Phosphorized Admiralty 18		Muntz	Approximately 1 foot downstream from tube-sheet at entrance end								
		Meramec Unit 2	25	Phosphorized Admiralty 18		Muntz	Approximately 1 ft downstream from tube-sheet at entrance end								
		Meramec Unit 3	20	Inhibited Admiralty 18		Muntz	X			X					
		Meramec Unit 4	18	Admiralty 18		Muntz	X			X					
26		Not specified	25	Arsenical Admiralty 18		Muntz - 1 1/4	X			X					
		4 Units not specified	29 28	Arsenical Admiralty 18		Muntz - 1 1/4							X		

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
26	(continued)	Not specified	11	Arsenical Admiralty 18	304SS 1" x .035"	Muntz - 1 1/4	Only on 2 occasions interior specific locations not known								
		4 Units not specified	4 3 2 1	304SS 20	304SS 22	304SS 1"	Defective welds in seaward tubes							X	
		2 Units not specified	9 8	304SS 22	304SS 20	Muntz - 1.25	Pinholes along tube due to organically caused oxygen attack								
		4 Units not specified	21 20 19 18	Arsenical Admiralty 18		Muntz 1.25				X					
27	Central Illinois Public Serv.	Newton	2	Admiralty 18	90-10 Cu-Ni 20	Carbon Steel 5/8									None
		Coffeen Unit 1	14	Admiralty 18	Stainless 20	Muntz - 1 1/4	X	Scattered throughout							11
		Coffeen Unit 2	7	Admiralty 18	Stainless 20	Muntz - 1 1/4	X	Overrolling of tube ends							950
		Meredosia	19	Arsenical Copper		Muntz - 1 1/2		Inside bundle location not known							
		Hutsonville	25	Arsenical Copper 18		Muntz - 1 1/4	X	Half behind tubesheets Half random							
		Grand Tower Unit 3	27 Retubed 17 yrs ago	Arsenical Copper 18	Stainless	Muntz - 1 1/2				X(Sand)	X(Steam)				
		Grand Tower Unit 4	20 Retubed 12 yrs ago	Arsenical Copper 18		Muntz 1 1/4				X (Sand)	X (Steam)				7
28	Rochester Gas & Electric	R.E. Ginna Unit 1	10	Admiralty	304SS 22	Muntz - 1 1/8		X			X				

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
29	Potomac Electric Power Co.	Chalk Point Unit 3	5	70-30 Cu-Ni 18		Al-Bronze 1 3/16		No leaks except for one time Accidental mechanical damage							
		Morgantown Units 1&2	8	70-30 Cu-Ni 18		Al-Bronze 1 1/4				X					
30	Connecticut Light & Power NUSCO	Montville Unit 6	8	70-30 Cu-Ni 18		Muntz		ID Biofouling causing thinning							
31	Hartford Electric Light NUSCO	Middletown Unit 4	6	Admiralty 18		ASTM B-171 1							X		
32	Florida Power	Anclote Unit 1	4	90-10 Cu-Ni 18		Muntz 1 1/8					X				
		Bartow Unit 1	22	90-10 Cu-Ni 18		Muntz 1 1/4	X	Denickelfication - Random Across upper 1/3 of condenser							
		Bartow Unit 2	19	90-10 Cu-Ni 18		Muntz 1 1/4	X	Denickelfication - Random Across upper 1/3 of condenser							
		Bartow Unit 3	16	90-10 Cu-Ni 18		Muntz	X	Denickelfication - Random Across upper 1/3 of condenser							
		Crystal River Unit 1	12	90-10 Cu-Ni 18 Retubed in 1973		Muntz - 1 1/4		Random along length - pit type corrosion							
		Cyrstal River Unit 2	9	90-10 Cu-Ni 18 Retubed in 1973		316SS 3 1/8		Random along length - pit type corrosion							
		Crystal River Unit 3	2	70-30 Cu-Ni		304LSS 1 1/8				X				X	

SUMMARY OF RESULTS OF HEI SURVEY ON CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
32	Florida Power (Continued)	Turner Unit 3	23	Arsenical Cu		Muntz - 1 1/4							X		
		Turner Unit 4	21	Inhibited Admiralty 18		Muntz - 1 1/4							X		
33	Baltimore Gas & Electric	Calvert Clifs Units 1 & 2	4	70-30 Cu-Ni 20		Al-Bronze 1 1/4		X	X	X	X				
		Riverside Generating Station	18	Admiralty B-111 18	304SS 18	Muntz 1 1/4			X Tubes plugged not specified						
		Wagner Unit 4	7	Al-Brass/18					Galvanic corrosion at inlet (rubber-lined water box)	X					
		Wagner Unit 1 & 2	22 20	Arsenical Al-Brass 18	Note 1	Muntz	X (Improper Rolling)		X	X			X		
		Wagner Unit 3	13	70-30 Cu-Ni 20	Note 1	Al Bronze	X		X	X			X		
		Riverside Unit 4 & 5	28 26	Arsenical Al-Brass 18	Note 1	Muntz	X		X	X			X		
		Westport Unit 4	29	Arsenical Al-Brass 18	Note 1	Muntz	X		X	X			X		
		Crane Unit 1 & 2	18 16	Arsenical Al-Brass 18	Note 1	Herculoy 420	X		X	X			X		
		Gould	27	Arsenical Al-Brass 18	Note 1	Muntz	X		X	X			X		

Note 1: Similar problems described for all units. Several of these units (not specified) have had the air cooler section retubed with 70-30 Cu-Ni or stainless

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks								
							Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
34	Delmarva Power		21	90-10 Cu-Ni 18 (3rd set of tubes-orig was Al Brass)		Admiralty Brass 1/2				X					
35	Tampa Electric Co.	Big Ben Station Unit 1	9	Orig. 316SS Retubed with Al-6x (1976) 22		AL-6X 1"	Scattered throughout length of tube								
		Big Ben Unit 2	6	316SS 22		316SS 1"	Scattered along length of tube								
		Big Ben Unit 3	3	316SS 22		316SS 1"	Scattered along length of tube								
36	Arizona Public Service		9	Admiralty C 18	304SS 22	Steel 1"	X				X				
			10	Admiralty 18	304SS 22	Steel 1"	X				X				
			1	Admiralty 18		Carbon Steel 1 1/8									None
37	Vermont Yankee Nuclear Power	Vermont Yankee	7	Admiralty 18	304SS 22	Muntz 1.125"									None
38	Boston Edison Co.	New Boston Station Unit 1	14	Al-Brass 18	316SS Changed to 90-10 Cu-Ni 20	Muntz 1 1/4	Along straight length								1097
		BHS Unit 2	18	Arsenic Al Brass - 18 changed to AL-6X 22 (1976)		Muntz 1 1/4"			X (No leakage since retubing with AL-6X)						
		BHS Unit 3	11	Al Brass 18		Muntz - 1 1/8	(AL-6X inserts-no more inlet erosion)		X	X					

SUMMARY OF RESULTS OF HEI SURVEY
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No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with ID Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
39	Public Service Co. of Colorado	Arapahoe Unit 1	29	Phosphorized Admiralty 18			Under deposit corrosion								
		Arapahoe Unit 2	28	Phosphorized Admiralty 18			Under deposit corrosion								
		Arapahoe Unit 3	28	Phosphorized Admiralty 18			Under deposit corrosion								
		Arapahoe Unit 4	24	Phosphorized Admiralty 18		Muntz 1.5"	Under deposit corrosion								
		Cherokee Unit 1	21	Phosphorized Admiralty 18	70-30 Cu-Ni since 1975	Muntz 1 1/4	Random leaks Since retubing of air cooler						X		
		Cherokee Unit 2	20	Phosphorized Admiralty 18	Epoxy Coated (1977)	Muntz 1 1/4"	Random leaks							X	
		Cherokee Unit 3	17	Inhibited Admiralty 18	Cu-Ni since 1970	Muntz 1 1/4"	Random leaks Since retubing air cooler						X		
		Cherokee Unit 4	11	Arsenical Admiralty 18	Cu-Ni	Muntz 1 1/8"	X	Random leaks							
40	Pennsylvania Power Co.	Bruce Mansfield Unit 1&2	4 2	Admiralty 18		Muntz					X				
41	Niagara Mowhawk	Nine Mine Point Unit 1	10	Admiralty 18	304SS	Muntz 1 1/4"			X						

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No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
42	Niagara Mowhawk (Continued)	Oswego Unit 5	3	Admiralty 18	70-30 Cu-Ni 304SS	Muntz 1 1/4"			X						
43	Consolidated Edison of N.Y.	Astoria Unit 3	21	Al-Brass 18		Naval Brass				X					
		Arthur Kill Unit 2	20	Al Brass retubed with Al Bronze (1968) Retubed with Ti (1978)		Naval Brass 1 1/2"	No leaks due to anything but mechanical damage since Ti installation								
		Ravenswood Unit 3	15	Al Bronze 18	70-30 Cu-Ni 18	1 1/4"				X					
		Astoria Unit 5	17	Al Brass 18	70-30 Cu-Ni	Silicon Bronze 1 1/2"	Lower 20 rows of tubes								
		Indian Point Unit 2	7	Admiralty 18		Silicon Bronze						X			
		Ravenswood Units 1&2	17 16	Al Brass 18	70-30 Cu-Ni	Al Bronze 1 1/4				X					
		Astoria Units 1&2	26 25	Al Brass/18 90-10 Cu-Ni since 1978 90-10 Cu-Ni since 1979		Muntz 1 1/2"				X					
		East River Unit 7	24	Al Brass 18		Muntz 1 1/2"	Operating experience not described								
		East River Unit 5&6	28 28	Al Brass 18		Muntz 1 1/2"	Lowest row of tubes inlet most severely damaged			X					
44	Wisconsin Public Serv.	Kewaunee Nuclear Plant	5	Admiralty 18	304SS 20	Carbon Steel 1 1/4"	X							X	
		Not specified	15	Arsenical 18		Muntz 1 1/4	Leak location not described								

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ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks								Total Plugged
							Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with [illegible] Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	
45	Central Power & Light	Victoria 4	24	Arsenical Admiralty/18		Muntz - 1 1/2		Leaks have been within tubes							
		Lon C Hill Unit 1	25	Arsenical Cu/18		Muntz - 1 1/2		Leaks have been within tubes							
		Lon C. Hill Unit 2	23	Arsenical Cu/18		Muntz - 1 1/2		Leaks have been within tubes							
		J.L. Bates Unit 1	21	Arsenical Admiralty/18		Muntz - 1 1/16		Leaks have been within tubes							
		Lon C. Hill Unit 3	20	Arsenical Admiralty/18		Muntz - 1 1/2		Leaks have been within tubes							
		J.L. Bates Unit 2	19	Arsenical Admiralty/18		Muntz - 1 1/4		Leaks have been within tubes							
		Victoria 5	16	Arsenical Admiralty/18	304SS/20	Muntz - 1 1/8		Leaks have been within tubes							
		Nueces Bay Unit 6	14	Al brass/18		Muntz - 1 1/16		Leaks have been within tubes							
		Victoria 6	11	304SS/22 304SS/20		304SS/1 1/8		Leaks have been within tubes							
		Lon C. Hill Unit 4	10	304SS/22 304SS/20		304SS/1 1/8		Leaks have been within tubes							
46	Wisconsin Electric Power	Port Washington 1 Units 1 and 2	44-36	Muntz/18				Leaks believed due to sand particle erosion							
		Port Washington Units 3, 4 and 5	31-30	Arsenial Admiralty/18				Leaks believed due to send particle erosion							

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No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with ID Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
46	Wisconsin Electric Power (Continued)	Oak Creek Unit 1	26	Admiralty/19		Steel - 1 1/4	Leaks believed due to sand particle erosion. One case of severe tube cracking due to a steady plate misalignment								
		Oak Creek Unit 2	25	Admiralty/19		Steel - 1 1/4	Leaks believed due to sand particle erosion								
		Oak Creek Units 3,4,5 & 6 (Original)	24-22	Aluminum/17		Steel - 1 1/4	Leaks believed due to sand particle erosion								
		Oak Creek Units 3,4, 5 & 6 (Retube)	?	SS	SS	Steel - 1	Experience not described								
		Oak Creek Unit 7 (Original)	14	Aluminum/17 SS/18		Steel - 1	Leaks believed due to sand particle erosion								
		Oak Creek Unit 7 (Retube)	?	SS	SS	Steel - 1 1/4	Experience not described								
		Oak Creek Unit 8	12	Admiralty Type B/18 304SS/20		Steel - 1 3/8	Leaks believed due to sand particle erosion								
		Valley Units 1 & 2	11-10	Arsenical Admiralty/18		Muntz - 1 1/4									None
		Point Beach Units 1&2	9-7	Admiralty/18 304SS/22		Muntz - 1 1/8		X		X					
47	Houston Light & Power	Greens Bayou 5	6	Inhibited Admiralty/18	70-30 Cu Ni/18	Muntz - 1	Leaks occur in the "hot"ends of the tubes. Corrosion and erosion seem to be major problems								

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ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc.	Total Plugged
47	Houston Light & Power (Continued)	Cedar Bayou 1	9	90-10 Cu Ni/18	70-30 Cu Ni/18	Muntz - 1 1/4	Leaks usually occur in tubes at "hot" end								
		Cedar Bayou 2	7	90-10 Cu Ni/18	70-30 Cu Ni/18	Muntz - 1 1/4	Erosion, some corrosion usually in the "hot" end of the tubes								
		Cedar Bayou 3	5	90-10 Cu Ni/18	70-30 Cu Ni/18	Muntz - 1 1/8	Erosion, some corrosion usually in the "hot" end of the tubes								
		D.H. Robinson #4	6	90-10 Cu Ni/18	70-30 Cu Ni/18	Muntz - 1 1/8	Most leakage occurs at "hot" end of tubes. Erosion evident in some instances.								
48	Florida Power & Light	Turkey Point 3 & 4 (Original)	7	Al brass/18	70-30 Cu Ni/18	Muntz - 1 1/8	Many tube leaks								
		Turkey Point 3&4 (Retube)	?	Titanium	Titanium	Muntz - 1 1/8	Experience not described								
		St. Lucie 1 (Original)	3	Al brass/18	70-30 Cu Ni/18	Muntz - 1 1/8	X (Service leaks)								
		St. Lucie 1 (Retube)	?	Titanium	Titanium	Al bronze/ (Integral grooving)	Experience not described								
		Manatee 1	3	Al brass/18	70-30 Cu Ni/18	Muntz - 1	X(1)	X							65
		Manatee 2	2	Al brass/18	70-30 Cu Ni-18	Muntz - 1		X							27
		Sanford 4	7	Al brass/18	70-30 Cu Ni/18	Muntz - 1 1/4								X (36)	39
		Sanford	5	Al brass/18	70-30 Cu Ni/18	Muntz - 1 1/4								X (15)	37
		Putnam 1		90-10 Cu Ni/20	90-10 Cu Ni/20	Muntz /1	X(Initial)								1
		Putnam 2	2	90-10 Cu Ni/20	90-10 Cu Ni/20	Muntz/1									0

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
48	Florida Power & Light (Continued)	Cape Canaveral 2	10	Al brass/18	70-30 Cu Ni/18	Muntz/1 1/4	Sulfate attack on Al brass tubing Found 117 leaks after chemical cleaning								340
		Fort Myers 2	10	Al brass/18	70-30 Cu Ni/18	Muntz/1 1/4	X	(Initial)							239
49	Philadelphia Electric	Chester 6	38	Admiralty/18		Muntz/1 1/4		Location of tube leaks not described							
		Cromby 1&2	25	Admiralty/18				Location of tube leaks not described							
		Delaware 7&8	27	Admiralty A/18		Muntz/1 1/4	X (Seldom)	Leaks from holes along length of tubes							
		Eddystone 1	19	Admiralty B/18 with 5" long "Alka Serts"	SS (.024" drawn over Admiralty (.025")	Muntz/7/8							X (inside)		
		Eddystone 2	19	Admiralty/18		Muntz/1 1/4							X		
		Eddystone 3&4	5-3	Admiralty B/18 with 304LSS/22 in impingement	304LSS/22	Muntz/7/8									None
		Peach Bottom 1&2	5	Admiralty/18 with 304SS/20 in impingement area	304SS/20	Muntz/1		X							
		Richmond	29	Admiralty/18				No specific cause for leaks pinpointed							
		Schuylkill Unit 1	22	Admiralty/18		Muntz/1 1/2				X	X				
		Southwork Unit 1 (Original)	18	Admiralty/B/18		Muntz/1 1/2		Location of leaks not described							

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SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
49	Philadelphia Electric (Continued)	Southwork Unit 2 (Original)	22	Arsenical Admiralty/19		Muntz - 1 1/2	Location of leaks not described								
		Southwork Unit 2 (Retube)	8	Arsenical Admiralty/19		Muntz/1	Location of leaks not described								
50	Nevada Power	Clark 3	18	Admiralty/18		Muntz	Leaks are somewhere in mid-span								
		Sunrise 1	15	Admiralty/18		Muntz - 1 1/4	Leaks are somewhere between tubesheets								
		Reid Gardner 1	14	Admiralty/18		Muntz - 1 1/4	Leaks are somewhere between tubesheets								
		Reid Gardner 2	12	Admiralty/18		Muntz/1	Leaks are somewhere between tubesheets								
51	Public Service Co. of N.H.	Merrimack Unit 1	20	304LSS/18 Admiralty on Periphery (Retubed 1970)		Carbon Steel 1.0"	No leakage since retube (See Note 1)								
		Merrimack Unit 2	10	304LSS 22		Carbon Steel 1"									
		Newington Station	5	90-10 Cu-Ni 18		Muntz - 1.25"	(Design modification following startup eliminated problem.)	X			X				
52	Detroit Edison	500 MWe	10	Admiralty/18 - 97.4% 304SS - 2.6%		Steel - 1 1/8"	X								
		750 Mwe Units 1-4	9-5	Admiralty/18 91.4% 70-30 Cu Ni- 8.6%		Steel - 1	X	X			X				

NOTE 1: Completely retubed in 1970 from Al 6061-T4. Both galvanic corrosion at tube ends and differential oxygen cell corrosion along tube length before retube.

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
53	Toledo Edison	Bay Shore 1	24	Phosphorized Admiralty brass/ 18		Muntz - 1 1/2	X	X	Also some erosion indicated						
		Bay Shore 2	20	Admiralty brass/ 19 Admiralty brass/ 18	90-10 Cu Ni/18	Muntz - 1 1/16	X	X	Also some erosion indicated						
		Bay Shore 3	16	Admiralty brass/ 19 304SS/22 Admiralty brass/ 18		Muntz - 1 1/2	X	X	Also some erosion indicated						
		Bay Shore 4	11	Admiralty brass/ 18 304SS/19 80-20 Cu Ni/18		Muntz/1	X	X	Also some erosion indicated						
		Acme Unit 2	28	Phosphorized Admiralty 18		Muntz - 1 1/2	X								
		Acme Unit 6	30	Phosphorized Admiralty 18		Muntz - 1 1/2	X								
		Acme Unit 5	38	Phosphorized Admiralty 18		Muntz - 1 1/2	X								
		Davis Besse	3	304SS/21	304SS/19	Steel-1"		X							
54	Cincinnati Gas & Electric	W.C. Beckjord Unit 6	10	As-Cu 18		Muntz 1"		No apparent leaks							
		Beckjord Unit 5	17	Arsenical Admiralty 18		Muntz 1"							X		

SUMMARY OF RESULTS OF HEI SURVEY ON CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Pitting or Problems with Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
54	Cincinnati Gas & Elec (Continued)	Beckjord Unit 4	21	Arsenical Admiralty 18		Muntz 1"		Tubes wearing thin at top of bundle			X				
		Beckjord Unit 3	25	Not Given 16		Muntz 1"	With leaks that have been encountered, they have been near drains from turbine oil spills (very few leaks)								
		Beckjord Unit 2	26	As-Cu 16		Muntz 1"		Few leaks (not a problem)							
		Beckjord Unit 1	27	As-Cu 16		Muntz 1"				(One time problem)	X				30
		Miami Fort Station Unit 7	4	High Copper Alloy	70-30 Cu-Ni	Muntz	X	(One leak only)							
		Miami Fort Station Unit 8	1	High Copper Alloy	70-30 Cu-Ni	Muntz	X	(Tube pulled out of tubesheets soon after startup)							
55	Illinois Power	Wood River Unit #4	25	Arsenical Cu/18		Steel - 1 1/2"							X		427
		Wood River Unit #5	15	Inhibited Admiralty/18		Muntz - 1 1/4"					X				200
		Hennepin Unit # 1	26	Ars Admiralty/ 18						X					
		Hennepin Unit #2	20	Ars Copper/18		Muntz - 1 1/2				X					
		Vermillion Unit #2 (Original)	23	Admiralty brass/18		Muntz - 1 1/2"		Leaks along length due to corrosion beneath deposits					X		84
		Vermillion Unit #1 (Original)	22	Admiralty brass/18		Muntz - 1 1/4"		Leaks along length due to corrosion deposits					X		466

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with ID Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
55	Illinois Power (Continued)	Vermillon Unit #1 & #2 (Retube)	2	Admiralty brass/18	Stainless	Muntz - 1 1/4		Not Specified							
		Baldwin Unit #3	4	90-10 Cu Ni/20	Stainless/20	Muntz - 7/8"	X	(Initial) Location of leaks in tubes is unknown							
		Baldwin Unit #2	6	Admiralty/18	SS304/20	Muntz-1	X	Location of leaks in tubes is unknown							
		Baldwin Unit #1	9	Admiralty/18	SS304/20	Muntz-1	X	Location of leaks in tubes is unknown							
		Havana Units 1-5	35	Arsenical Copper 18		Muntz - 1 1/4		Leak location not specified							
		Havana Unit 6	1	304SS/ 22		304SS 1"		Not specified							
50	Carolina Power and Light	Cape Fear Unit 5	23	Admiralty Type B/18		Muntz - 7/8		Location of leaks along tube length not described							
		Cape Fear Unit 6	21	Admiralty/18		Muntz - 7/8		Location of leaks along tube length not described							
		Ashville Unit 1 (Original)	12	Inhibited Admiralty/18		Steel - 1 1/8							X		458
		Ashville Unit 1 (Retube of A/C)	3	Inhibited Admiralty/18	304SS/20	Steel - 1 1/8		Location of leaks not described							4
		Ashville Unit 2	8	304SS		Steel - 1 1/8									None

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks								Total Plugged
							Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with OD Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	
56	Carolina Power & Light (Continued)	Sutton Unit 1	25	9-10 Cu Ni/18		Naval brass - 1 1/2		Location of leaks not described							
		Sutton Unit 2	24	90-10 Cu Ni/18		Muntz - 1 1/4		Location of leaks not described							
		Sutton Unit 3	7	90-10 Cu Ni/18 SS on periphery		Naval brass - 1		Location of leaks not described							
		Roxboro 1	13	Inhibited Admiralty/18	Retubing with SS	Steel - 1 1/8	X			X	X		X		
		Roxboro 2	11	Inhibited Admiralty/18	Retubed with SS in 1977	Muntz - 7/8	X	X			X		X		
		Roxboro 3	6	304SS/22		Muntz - 1 1/4				X					
		H. F. Lee Unit 1	27	High Copper Alloy/20	SS/20	Muntz - 1 1/4					X				
		H. F. Lee Unit 2	28	Phos. Admiralty/ 18 (Retubed in 1971)	SS	Muntz - 1 1/4					X				
		H. F. Lee Unit 3	18	Inhibited Admiralty/18		Muntz - 1 1/4					X				
		Robinson #1 (Original)	9	Aluminum		Steel - 1 1/2		Corrosion of tube ID							
		Robinson #1 (1st Retube)	9	Aluminum		Steel - 1 1/2		Corrosion of tube ID							
		Robinson #1 (2nd Retube)	1	439 SS/22 304 SS/22											None
		Robinson #2	8	Admiralty/18	304SS/22	Muntz - 1 1/8			X	X					

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Vibration	Thinning at Tube Supports	ID Inlet Erosion	Baffle or Problems with ID Erosion	Stress Corrosion Cracking	Air Cooler Section	Foreign Objects -Turbine, etc	Total Plugged
56	Carolina Power and Light (Continued)	Brunswick Unit 1 & 2	5	90-10 Cu Ni/18		90-10 Cu Ni - 1	X			X	X				
		Weather-spoon Unit 3	27	Al brass/18 Chose Superboy (88 Cu/10Zm/25b)		Muntz - 1 1/4					X				
57	Bedford Gas and Edison Light	Unit 1 (Original)	8	Al brass/18	SS/18	Muntz - 1 1/8	High failure rate of SS tubes resulted in replacement in 3 years. Mainly shells lodged in tubes with subsequent erosion/ corrosion								
		Unit 2 (Retube)	3	90-10 Cu Ni	70-30 Cu Ni	Muntz - 1 1/8	Shells lodged in tubes result in erosion/ corrosion			X					
58	El Paso Electric	Newman Station 4	4	Admiralty/18		Muntz - 1									None
		Rio Grande Unit 8	7	Admiralty/18		Muntz - 7/8	X One time pullout of 100 tubes from tubesheet								
59	Maine Yankee	Unit 1	7	Aluminum brass/ 18 70-30 Cu Ni/18 AL-6X/18		Muntz - 1	Pitting from ID along length of tubes. Some plugged tubes have broken roll between tube and tubesheet by thermal growth								
60	Electric Energy, Inc.	Units 1 - 6 (Original)	26-24	Admiralty brass/ 18	Admiralty brass/18	Muntz - 1 1/2				X (Lodged debris)	X		X		
		Units 1 - 6 (Retubed)	7	Admiralty brass/18 after original tube thickness of 0.049" reduced to 0.030" by ID corrosion	304SS/22		Lodged debris and corrosion on tube ID			X					

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with on Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
61	Pennsylvania Power & Light	Holtwood Unit 17	25	Admiralty Brass		Muntz	X						X		
		Sunbury Unit 1&2	29	Admiralty 18			X						X		
		Sunbury Unit 3&4	27	Admiralty 18			X						X		
		Martins Creek Unit 1&2	24	Admiralty 18		Muntz	X						X		
		Martins Creek Unit 3&4	4 2	304SS /22		Carbon Steel 1-3/8"					X				
		B. Island Unit 1	18	Admiralty 18	304SS	Muntz > 1 1/2"					X		X		
		B. Island Unit 2	14	Admiralty 18	304SS	Muntz > 1 1/2"					X		X		
		B. Island Unit 3	10	304SS 22		Steel 1-1/4"	X							X	
		Mont. Unit 1 & 2	7 6			Carbon Steel 1"		Leaks rare. Cause not certain							4
62	Pennsylvania Electric Co.	Keystone Unit 1	12	304SS 22		Carbon Steel 1"	Baffle installed to eliminate problem				X				
		Keystone Unit 2	11	304SS 22		Carbon Steel 1"	Baffle installed to eliminate problem				X				
		Conemaugh Unit 1	9	304SS 22		Carbon Steel					X				
		Conemaugh Unit 2	8	304SS 22		Carbon Steel					X				

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
62	Pennsylvania Electric Co. (Continued)	Homer City Unit 1&2	10 10	304SS 22		Carbon Steel 1 1/8"					X				
		Seward Unit 5	22	304SS 22 (Retubed 1970)		Muntz .885"	X								
63	Duke Power Co.	Marshall Steam Station Units 1&2	14 13	Admiralty 18	304SS	ASTM B171 1 1/2"					X				
		Marshall Units 3&4	10 9	304SS 22		Carbon Steel 1 3/8"					X				
		Lee Unit 2	22	Not Given/18		Admiralty	Leak location random								
		Riverbend Unit 4	27	Inhibited Admiralty 18		Muntz 1 1/2"					X		X		
		Riverbend Unit 5	27	Inhibited Admiralty 18		Muntz 1 1/2"					X		X		
		Riverbend Unit 6	25	Admiralty 18		Muntz 1 1/2"					X		X		
		Riverbend Unit 7	25	Admiralty 18		Muntz 1 1/2"					X		X		
		Allen Unit 1	22	Admiralty 18	304SS (1964)	Muntz 1 1/2"	Location unknown								3
		Allen Unit 2	22	Admiralty 18	304SS (1966)	Muntz 1 1/2	Location unknown								8
		Allen Unit 3	20	Admiralty 18	304SS (1965)	Muntz 1 1/2	Location unknown								12

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
63	Duke Power Co. (Continued)	Allen Unit 4	19	Admiralty 18	304SS (1966)	Muntz 1 1/2"	Location unknown								9
		Allen Unit 5	18	Admiralty 18	304SS (1964)	Muntz 1 1/2"	Location unknown								4
		Belews Creek Unit 1	7	304SS 22		Carbon Steel - 1 1/2"					X				
		Belews Creek Unit 2	6	304SS 22		Carbon Steel - 1 1/2"					X				
		Buck Unit 5&6	26	Admiralty 18		Muntz 1 1/2"	X (Rolling)			Other locations unknown					
		Buck Unit 3	38	Admiralty 18		Muntz - 1 1/2"	X (Rolling)			Other locations unknown					
		Buck Unit 1&2	63 (Retubed in 1969)	Admiralty 18		Muntz	X (Rolling)								
		Oconee Unit 1, 2, 3	6 6 5	304SS 22		Carbon Steel - 1 1/4"	X								
		Cliffside Unit 5	7	Admiralty 18	Stainless 20	Muntz 1 3/8"				Internal locations					
64	Commonwealth Edison		6	304SS 22		Muntz 1.005"	X (Rolling) Some due to aux. piping connections								
			3	304SS 22		Muntz 1.005"	X (Rolling) Some due to aux. piping connections								
		U-4	1	304SS 22		Muntz 1"	X (Rolling)			Internal locations					

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
64	Commonwealth Edison (Continued)	U-3	2	304SS 22		Muntz 1"	X (Rolling)				Internal locations				
		U-2	1	304SS 22		Muntz 1"	X (Rolling)				Internal locations				
		U-1	1	304SS 22		Muntz 1"	X (Rolling)				Internal locations				
			29	Phosphorized Admiralty 18		Muntz - 1 1/4"	X			X (Sand)					88
			20	Arsenical Admiralty 16		Carbon Steel - 1 1/2				X (Sand-use inserts)	X (Steam)				
		Waukegan Unit 8	17	Admiralty 18	304SS	Muntz - 1 1/4"				X			X		
		Juliet Unit 6	20	Phosphorized Admiralty 18		Muntz - 1 1/4"							X	X	
			14	Admiralty 18	Stainless 20	Muntz 1"		Scattered locations							
			13	Admiralty 18	Stainless 20	Muntz 1"							X		
			21	Phosphorized Admiralty 18		Muntz - 1 1/4	X (Roll)		X						
			18	Phosphorized Admiralty 18		Muntz 1 1/4	X (Roll)		X						
			12	Admiralty 18	304SS	Muntz 1 1/4		Middle locations							

SUMMARY OF RESULTS OF HEI SURVEY
ON
CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine,etc	Total Plugged
64	Commonwealth Edison (Continued)		11	Admiralty/18	304SS/22	Muntz - 1 1/4		Middle locations							
			24	Phosphorized Admiralty/18		Muntz - 1 1/2					X		X		
			24	Phosphorized Admiralty/18		Muntz - 1 1/2					X		X		
			21	Phosphorized Admiralty/18	304SS	Muntz - 1 1/2							X		
			16	Admiralty/18	316SS/20	Muntz - 1 1/4							X		
		Stateline Unit 3	24	Admiralty/18		Muntz				X					10
		Fisk Unit 19	20	Inhibited Admiralty		Muntz - 1 1/2					X			X	
65		Unit 1 2 3 4	8 9 7 5	As-Cu/18		Muntz			X						
66	Arkansas Power & Light		6	Admiralty/18		Muntz - 1 1/4								X	

SUMMARY OF RESULTS OF HEI SURVEY ON CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with On Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
67	San Diego Gas & Electric	South Bay Unit 3	15	90-10 Cu-Ni 20		Muntz 1"	X			X					
		South Bay Unit 4	8	90-10 Cu-Ni 20		Muntz 1"	X			X					
68	Texas Utilities	Big Brown Unit 1&2	8 7	304SS 22		Carbon Steel	Not	specified							
		Monticello Units 1&2	5 4	304SS 22		Carbon Steel	X	X	X			X			
		Martin Lakes Units 1&2	2 1	304SS 22		Carbon Steel		X	X						
69	Gulf Power		6	Al-Brass 18		Muntz - 1 1/8						X			
70	Central Illinois Light Co.	E.D. Edwards Unit 1	19	Inhibited Admiralty 18		Muntz 1 1/2					X				
		E.D. Edwards Unit 2	11	Admiralty 18		Muntz - 1 1/4					X				
		R.S. Wallace Unit 7	21	Admiralty 18		Muntz					X				
71	Southwestern Public Service	Nichols Unit 1	19	Admiralty 18		Muntz - 1 1/4		Other	than	tube	sheet				
		Nichols Unit 2	17	Admiralty 18		Muntz - 1 1/4		Other	than	tube	sheet				

SUMMARY OF RESULTS OF HEI SURVEY ON CONDENSER PERFORMANCE

No.	Utility	Plant	Age (yr)	Tube Bundle/BWG	Air Cooler/BWG	Tubesheet Material/ Thickness	Leaks: Tube to Tubesheet	Leaks: Vibration	Leaks: Thinning at Tube Supports	Leaks: ID Inlet Erosion	Leaks: Baffle or Problems with OD Erosion	Leaks: Stress Corrosion Cracking	Leaks: Air Cooler Section	Leaks: Foreign Objects -Turbine, etc	Total Plugged
71	Southwestern Public Service (Continued)	Cunningham Unit 2	13	Admiralty 18		Muntz - 1 1/4				X					
		Cunningham Unit 1	22	Arsenical Admiralty		Muntz 1							X		
		Plant X Unit 3	24	Admiralty 18		Muntz 1"							X		
		Plant X Unit 4	15	Admiralty 18		Muntz - 1 1/4							X		
		Harrington Unit 1	3	316LSS 22		Muntz - 1 1/8	Leak caused by welding lead NRC during hotwell repair								
		Jones Unit 1	8	316SS 22		Muntz - 1 1/8	Inside bundle								2
		Jones Unit 2	5	316SS 22		Muntz - 1 1/8									None
72	Iowa Public Service	George Neal Unit #1	16	Admiralty/18		Silicon bronze/	Location of leaks in tubes not described								36
		George Neal Unit #2	7	Admiralty/18			Location of leaks in tubes not described								50
		George Neal Unit #3	3	304SS/20		Steel	Location of leaks in tubes not described								56
73	Iowa Electric Light and Power	BWR	5	304SS/22		Muntz - 1 1/8	X								
74	Northern States Power Company	Prairie Island Units 1 & 2	6 5	304SS/22	304SS/22	Steel - 1"		Cause of leakage not determined							

APPENDIX C

FLOW INDUCED VIBRATION CALCULATIONS

Title: Comparison of Connors and Westinghouse Calculational Approaches for Prediction of Critical Fluidelastic Velocity
Calculated by: Jim Hibbard Date: Jul 11, 79
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Project: EPRI Condenser Study

APPENDIX C

PART 1

Purpose: To compare the prediction of the critical fluidelastic velocity as predicted by the Connors and Westinghouse calculational approaches.

Summary: Comparison of the expressions for the critical velocity shows that the comparison is dependent upon constants that reflect the two flow situation and the tube bundle geometry. For typical values of these constants

$$0.12 \le \frac{V_c}{V_W} \le 0.83 .$$

Calculation:

1) W Equation

$$L = 21.8 \left[\frac{S E I \delta_0}{\rho V_1^2 D}\right]^{1/4} \quad (1)$$

where
$L =$ in
$E =$ lb_f/in^2
$I =$ in^4
$\rho =$ lb_m/ft^3
$V =$ ft/s
$D =$ in

This equation assumes both ends simply supported.

If one end is fixed then,

$$1.25\,L = 21.8\left[\frac{S_c\,E\,I\,\delta_o}{\rho V^2 D}\right]^{1/4} \quad (2)$$

2) Connors Equation

$$\frac{V_c}{f_n D} = \beta\sqrt{\frac{m_o\,\delta_n}{\rho_o D^2}} \quad (3)$$

3) Comparison

Compare equations 1 and for a simply supported, uniformly loaded beam.

From Roark,

$$f = \frac{K}{2\pi}\sqrt{\frac{EIg}{m_o \ell^4}} \quad (4)$$

$K = 15.4$, Fixed-pinned
$K = 9.87$, pinned-pinned

Substituting into eq. 3 and solving for V gives

$$V_c = \beta\frac{K}{2\pi}\sqrt{\frac{EIg}{m\,\ell^4}\,\frac{m\,\delta_n}{\rho}} = \beta\frac{K}{2\pi}\sqrt{\frac{EIg\,\delta_o}{\rho\,\ell^4}\times 144}$$

The units necessary are

$E = lb_f/in^2$
$I = in^4$
$\rho = lb_m/ft^3$
$\ell = in$
$g = 32.17 \frac{lb_m - ft}{lb_f - s^2}$

Then, $V_2 = \beta \frac{K}{2\pi} 12 \sqrt{g} \sqrt{\frac{EI\delta}{\rho \ell^4}}$ (5)

Solving eq 1 for V_1 gives,

$$\ell^4 = 21.8^4 \frac{S_c E I \delta_o}{\rho V_1^2 D}$$

$$V_1^* = 21.8^2 \sqrt{\frac{S_c E I \delta_o}{\rho D \ell^4}}$$

Forming the ratio $\frac{V_2}{V_1^*}$ gives

$$\frac{V_2}{V_1^*} = \frac{\beta \frac{K}{2\pi} 12\sqrt{g} \sqrt{\frac{EI\delta}{\rho \ell^4}}}{21.8^2 \sqrt{\frac{S_c E I \delta_o}{\rho D \ell^4}}}$$

$$\frac{V_2}{V_1^*} = \frac{\beta \frac{K}{2\pi} 12 \sqrt{g}\sqrt{D}}{21.8^2 \sqrt{S_c}}$$

However, the Westinghouse velocity, V_1^*, is the trunk velocity, while the Connors velocity is in the tube gap.

$$\text{Let} \quad V_1 = V_1^* \frac{P}{P-D}$$

Then,

$$\frac{V_2}{V_1} = \frac{\beta \frac{K}{2\pi} 12 \sqrt{g} \sqrt{D}}{21.8^2 \sqrt{S_c}} \left(1 - \frac{D}{P}\right)$$

Substitute $K = 9.87$, $g = 32.2$, and $S = 1$, then

$$\frac{V_2}{V_1} = 0.225 \beta \sqrt{D} \left(1 - \frac{D}{P}\right)$$

Set limits on the range of $\frac{V_2}{V_1}$ making the following assumptions:

1. $3.3 \le \beta \le 9.9$
2. $.875 \le D \le 1.25$
3. $1.2 \le \frac{P}{D} \le 1.5$

Case 1. Set $\beta = 9.9$, $D = 1.25$, $\frac{P}{D} = 1.5$

$$\frac{V_2}{V_1} = 0.83$$

Case 2. Set $\beta = 3.3$, $D = .875$, $\frac{P}{D} = 1.2$

$$\frac{V_2}{V_1} = .12$$

The comparison is dependent upon the assumption that the bundle's velocity V_1 can be related to the trunk velocity by $V_1 = V_1^* \frac{P}{P-D}$. This will give conservative and high values for the velocity. Around the sides and at the bottom of the bundle this assumption becomes poor, with the result that the Connors and Westinghouse equations will compare more favorably.

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APPENDIX C

PART 2

Purpose: To calculate a reasonable lower limit on $\frac{m\delta}{\rho d^2}$ for condenser operation.

Summary: Assuming 2.85 Hz

$$\frac{m\delta}{\rho d^2} = 559$$

Calculation:

Let $\rho_T \equiv$ tube metal density
$\rho_H \equiv$ water density
$d_i \equiv$ inside dia

Then,

$$\frac{m\delta}{\rho d^2} = \frac{\left[\rho_T \frac{\pi}{4}(d^2 - d_i^2) + \rho_w \frac{\pi}{4} d_i^2\right]^{*} \delta}{\rho d^2}$$

$$\frac{m\delta}{\rho d^2} = \frac{\pi \delta \left[\rho_T + \left(\frac{d_i}{d}\right)^2 (\rho_w - \rho_T)\right]}{4\rho}$$

* The virtual mass due to steam on the outside of the tube is negligible and not included in this calculation.

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Title: Lower Limit on $\frac{m\delta}{\rho d^2}$

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Assume

$\delta = .036$
$\rho = 1/243.5 = .00411$; @ 2.5" Hg
$\rho_w = 1/.01613 = 62.00$; @ P=1atm + T=100°F
$\rho_T = 281.7$; titanium
$d = 1.25$ in
$d_i/d = .955$; 22 gage

Then, $\frac{m\delta}{\rho d^2} = 560$