ASME OM-2015
(Revision of ASME OM-2012)

Operation and Maintenance of Nuclear Power Plants

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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Two Park Avenue • New York, NY • 10016 USA

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The next edition of this Code is scheduled for publication in 2017.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Code. Interpretations are published on the Committee Web page and under go.asme.org/InterpsDatabase. Periodically certain actions of the ASME OM Committee may be published as Cases. Cases are published on the ASME Web site under the OM Committee Page at go.asme.org/OMcommittee as they are issued.

Errata to codes and standards may be posted on the ASME Web site under the Committee Pages to provide corrections to incorrectly published items, or to correct typographical or grammatical errors in codes and standards. Such errata shall be used on the date posted.

The Committee Pages can be found at http://cstools.asme.org/. There is an option available to automatically receive an e-mail notification when errata are posted to a particular code or standard. This option can be found on the appropriate Committee Page after selecting "Errata" in the "Publication Information" section.

The American Society of Mechanical Engineers
Two Park Avenue, New York, NY 10016-5990

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(A Detailed Contents Precedes Each Division)

FOREWORD

This document was developed and is maintained by the ASME Committee on Operation and Maintenance (OM Committee) of Nuclear Power Plants. The Committee operates under procedures accredited by the American National Standards Institute as meeting the criteria of consensus procedures for American National Standards.

Due to the additional time required to consolidate the OM Code and OM-S/G documents, the 2009 edition encompassed all material that would have been included in the 2007 edition, 2008 addenda, and 2009 addenda.

The 2012 edition of Operation and Maintenance of Nuclear Power Plants included revisions to various sections of Division 1, along with the addition of Mandatory Appendix V. Approved code cases and interpretations were also added.

The OM Committee develops, revises, and maintains codes, standards, and guides applicable to the safe and reliable operation and maintenance of nuclear power plants.

This publication, the 2015 edition of Operation and Maintenance of Nuclear Power Plants, was approved by the ASME Board on Nuclear Codes and Standards. ASME OM-2015 was approved by the American National Standards Institute on January 8, 2015.

PREPARATION OF TECHNICAL INQUIRIES TO THE COMMITTEE ON OPERATION AND MAINTENANCE OF NUCLEAR POWER PLANTS

INTRODUCTION

The ASME Committee on Operation and Maintenance of Nuclear Power Plants meets regularly to conduct standards development business. This includes consideration of written requests for interpretations, Code Cases, and revisions to the Operation and Maintenance Code and development of new requirements as dictated by technological development. This supplement provides guidance to Code users for submitting technical inquiries to the Committee. Technical inquiries include requests for revisions or additions to the Code requirements, requests for Code Cases, and requests for Code interpretations.

Code Cases may be issued by the Committee when the need is urgent. Code Cases clarify the intent of existing Code requirements or provide alternative requirements. Code Cases are written as a question and a reply, and are usually intended to be incorporated into the Code at a later date. Code interpretations provide the meaning or the intent of existing requirements in the Code and are also presented as a question and reply. Both Code Cases and Code interpretations are published by the Committee.

The Code requirements, Code Cases, and Code interpretations established by the Committee are not to be considered as approving, recommending, certifying, or endorsing any proprietary or specific design or as limiting in any way the freedom of manufacturers or constructors to choose any method of design or any form of construction that conforms to the Code requirements.

Moreover, ASME does not act as a consultant on specific engineering problems or on the general application or understanding of the Code requirements. If, based on the inquiry information submitted, it is the opinion of the Committee that the inquirer should seek assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

As an alternate to the requirements of this supplement, members of the Committee and its subcommittees, subgroups, and working groups may introduce requests for Code revisions or additions, Code Cases, and Code interpretations at their respective Committee meetings or may submit such requests to the secretary of a subcommittee, subgroup, or working group.

All inquiries that do not provide the information needed for the Committee's full understanding will be returned.

INQUIRY FORMAT

Submittals to the Committee shall include:

(a) Purpose. Specify one of the following:

(1) revision of present Code requirement(s)
(2) new or additional Code requirement(s)
(3) Code Case
(4) Code interpretation

(b) Background. Provide the information needed for the Committee's understanding of the inquiry, being sure to include reference to the applicable Code subsection, appendix, edition, addenda, paragraphs, figures, and tables. Preferably, provide a copy of the specific referenced portions of the Code.

(c) Presentations. The inquirer may desire or be asked to attend a meeting of the Committee to make a formal presentation or to answer questions from the Committee members with regard to the inquiry. Attendance at a committee meeting shall be at the expense of the inquirer. The inquirer's attendance or lack of attendance at a meeting shall not be a basis for acceptance or rejection of the inquiry by the Committee.

CODE REVISIONS AND ADDITIONS

Requests for Code revisions or additions shall provide the following:

(a) Proposed Revisions or Additions. For revisions, identify the requirements of the Code that require revision and submit a copy of the appropriate requirements as they appear in the Code, marked up with the proposed revision. For additions, provide the recommended wording, referenced to the existing Code requirements.

(b) Statement of Need. Provide a brief explanation of the need for the revision(s) or addition(s).

(c) Background Information. Provide background information to support the revision(s) or addition(s), including any data or changes in technology that form the basis for the request that will allow the Committee to adequately evaluate the proposed revision(s) or addition(s). Sketches, tables, figures, and graphs should be submitted as appropriate. When applicable, identify any pertinent paragraph in the Code that would be affected by the revision(s) or addition(s) and paragraphs in the Code that reference the paragraphs that are to be revised or added.

CODE CASES

Requests for Code Cases shall provide a *Statement of Need* and *Background Information* similar to that defined in subparas. (b) and (c) of the "Code Revisions and Additions" section. The proposed Code Case should identify the Code Section and Division, and be written as a *Question* and *Reply* in the same format as existing Code Cases. Requests for Code Cases should also indicate the applicable Code edition(s) and addenda to which the proposed Code Case applies.

CODE INTERPRETATIONS

Requests for Code interpretations shall provide the following:

(a) Inquiry. Provide a condensed and precise question, omitting superfluous background information and, when possible, composed in such a way that a "yes" or a "no" *Reply*, possibly with brief provisos, is acceptable. The question should be technically and editorially correct.

(b) Reply. Provide a proposed *Reply* that will clearly and concisely answer the *Inquiry* question. Preferably, the *Reply* should be "yes" or "no," possibly with brief provisos.

(c) Background Information. Provide any background information that will assist the Committee in understanding the proposed *Inquiry* and *Reply*.

SUBMITTALS

Submittals to and responses from the Committee shall meet the following:

(a) Submittal. Inquiries from Code users shall preferably be submitted in typewritten form; however, legible handwritten inquiries will also be considered. They shall include the name, address, telephone number, and fax number, if available, of the inquirer and be mailed to the following address:

Secretary
Committee on Operation and Maintenance of
Nuclear Power Plants
The American Society of Mechanical Engineers
Two Park Avenue
New York, NY 10016-5990

(b) Response. The Secretary of the Operation and Maintenance Committee shall acknowledge receipt of each properly prepared inquiry and shall provide a written response to the inquirer upon completion of the requested action by the Committee.

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PREFACE

GENERAL

In 2008, the OM Committee directed that the two separately published OM Code and the OM Standards and Guides (OM-S/G) publications be combined into one document. This was done to ensure all of our standards and guides documents were readily available to users of the OM Code products. Some of the standards and guides were originally developed as part of the current operating nuclear power plants pre-operational testing program conducted during the 1970s and 1980s. These standards and guides will be useful for power uprate projects and for new reactor design plant construction. Combining the OM Code and OM-S/G into one document makes the publication schedules for the Committee more efficient and easier to track.

ORGANIZATION

The consolidated code, standards, and guides for nuclear power plants, titled Operation and Maintenance of Nuclear Power Plants, are arranged into three distinct divisions. The titles of some of the sections were shortened to simplify the presentation purely for the user's ease of review and use. Reference to the individual published code, standard, or guide should be made for the specific title and the application requirements. Subsequent changes made to the Division contents will be detailed in future publications in separately listed summary of changes sections. Interpretations and Code Cases are included as a separate section following Division 3 for the user's convenience.

Division 1: OM Code: Section IST

Subsection ISTA	General Requirements
Subsection ISTB	Inservice Testing of Pumps — Pre-2000 Plants[1]
Subsection ISTC	Inservice Testing of Valves
Subsection ISTD	Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers)
Subsection ISTE	Risk-Informed Inservice Testing of Components
Subsection ISTF	Inservice Testing of Pumps — Post-2000 Plants[2]

Mandatory Appendices

I Inservice Testing of Pressure Relief Devices
II Check Valve Condition Monitoring Program
III Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies
IV Pneumatically and Hydraulically Operated Valves (to be provided at a later date)
V Pump Periodic Verification Test Program

Nonmandatory Appendices

A Preparation of Test Plans
B Dynamic Restraint Examination Checklist Items
C Dynamic Restraint Design and Operating Information
D Comparison of Sampling Plans for Inservice Testing of Dynamic Restraints
E Flowcharts for 10% and 37 Snubber Testing Plans
F Dynamic Restraints (Snubbers) Service Life Monitoring Methods
G Application of Table ISTD-4252-1, Snubber Visual Examination
H Test Parameters and Methods
J Check Valve Testing Following Valve Reassembly
K Sample List of Component Deterministic Considerations

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[1] *Pre-2000 plant:* a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

[2] *Post-2000 plant:* a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

Division 2: OM Standards

Division 3: OM Guides

ASME OM-2015
SUMMARY OF CHANGES

Following approval by the ASME Committee on Operation and Maintenance and ASME, and after public review, ASME OM-2015 was approved by the American National Standards Institute on January 8, 2015.

Changes given below are identified on the pages by a margin note, **(15)**, placed next to the affected area.

Page	*Location*	*Change*
7	ISTA-2000	Definitions of *cold shutdown outage* and *refueling outage* added
24, 25	ISTC-3521	Revised in its entirety
	ISTC-3522	Revised in its entirety
33	ISTD-1750	Revised
34	ISTD-2000	(1) Definitions of *fuel cycle, successful test campaign, test campaign, test interval,* and *unanticipated transient dynamic event* added (2) Definition of *inaccessible snubbers* revised
35	ISTD-3240	Added
38, 39	ISTD-5200	Revised
	ISTD-5240	Revised
	ISTD-5252	Revised
	ISTD-5262	Revised
	ISTD-5263	Revised
	ISTD-5271	Subparagraph (a) revised
41, 42	ISTD-5500	Revised
	ISTD-6200	Revised
	ISTD-9300	Subparagraph (b) revised
43	ISTE-1100	Footnote 1 added
44	ISTE-3100	(1) Previous subparagraph (e) deleted and subparagraph (f) redesignated as (e) (2) Last paragraph added
	ISTE-3210	(1) Revised (2) Footnote 2 (previously footnote 1) revised
46, 47	ISTE-4220	Subparagraph (d)(4)(e) relocated as (d)(3)(-d) and subsequent subparagraphs redesignated

Page	*Location*	*Change*
	ISTE-4240	Subparagraph (b) revised
49	ISTE-5300	Revised
	ISTE-5400	Revised in its entirety
60	I-1350	Subparagraph (a) revised
61	I-2000	Revised
	I-3000	Title revised
	I-3120	Revised
	I-3125	Added
62	I-3220	Revised
	I-3225	Added
	I-3250	Revised
63	I-3320	Revised
	I-3325	Added
64	I-3420	Title and subparagraphs (a) and (b) revised
	I-3425	Added
	I-3430	Subparagraphs (a) and (b) revised
65–67	I-4000	Title revised
	I-4110	Subparagraphs (a) and (g) revised
	I-4120	Subparagraph (h) revised
	I-4130	Subparagraph (g) revised
	I-5000	Title revised
68	Table I-4220-1	Title revised
	I-6000	Deleted
	I-7000	Deleted
	I-8000	Deleted
	I-9000	Deleted
69, 70	II-4000	Subparagraph (b)(1)(-f) revised
72	III-3610	Revised
125	Part 3, para. A-2.3.3	Second metric value corrected by errata to read 2 540 mm/s
139	Part 3, Nonmandatory Appendix I	Nomenclature for ϵ corrected by errata to read $\times\ 10^{-4}$
159–171	Part 16	Paragraphs 1 through 7.3 revised in their entirety and Table 1 added
175	Part 16, Fig. C-1	Callout revised
178	Part 16, Fig. C-4	Symbols for pressure corrected by errata to read $P_2 - P_3$ in two places
204, 205	Part 21, C-2.1.2.1	In subparagraph (b), first $R = 1$ corrected by errata to read $R \neq 1$

Page	*Location*	*Change*
209	Part 21, C-2.2.4.1	In subparagraph (b), first $R = 1$ corrected by errata to read $R \neq 1$
210	Part 21, C-2.2.6.1	In subparagraph (b), second $R = 0$ and $R =$ infinity corrected by errata to read $R \neq 0$ and $R \neq$ infinity
213, 217	Part 21, C-3.2	In equation (C-15) and its nomenclature, one h_j corrected by errata to read $\dot{h}_j$
227	Part 21, C-7.3	In second paragraph, m corrected by errata to read $\dot{m}$
285	Part 28, VI-3.5	Second cross-reference corrected by errata
286	Part 28, VI-3.5.2.1.1	In subparagraph (c), cross-reference corrected by errata
	Part 28, VI-3.5.2.1.4	In subparagraphs (a) and (b)(2), cross-references corrected by errata
287	Part 28, VI-3.5.2.2.1	Cross-references corrected by errata
	Part 28, VI-3.5.2.2.2	Cross-reference corrected by errata
293	Part 28, Fig. B-2	Previous drawing reinstated by errata
302, 303	Part 28, C-9.1.2.1	Second equation for β_T corrected by errata to read positive 4.5
364, 365	Part 11, B-2	First listing for l corrected by errata to read I
	Part 11, B-3	In equations (B-7) and (B-9), l corrected by errata to read I
388	Part 14, 3.1	OM-Code–1990 deleted by errata
414	Part 23, 3	OM-S/G–1993 deleted by errata

SPECIAL NOTE:

The Interpretations and Code Cases to ASME OM are included in this edition as a separate section at the end of this document for the user's convenience.

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DIVISION 1: OM CODE: SECTION IST

CONTENTS

Subsection ISTA
General Requirements

ISTA-1000 INTRODUCTION

ISTA-1100 Scope

Section IST establishes the requirements for preservice and inservice testing and examination of certain components to assess their operational readiness in light-water reactor nuclear power plants. It identifies the components subject to test or examination, responsibilities, methods, intervals, parameters to be measured and evaluated, criteria for evaluating the results, corrective action, personnel qualification, and record keeping. These requirements apply to

(a) pumps and valves that are required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident

(b) pressure relief devices that protect systems or portions of systems that perform one or more of the three functions identified in subpara. (a)

(c) dynamic restraints (snubbers) used in systems that perform one or more of the three functions identified in subpara. (a), or to ensure the integrity of the reactor coolant pressure boundary

ISTA-1200 Jurisdiction

The jurisdiction of Section IST covers individual components that have met all the requirements of the construction code commencing at the time when the construction code requirements have been met, irrespective of the physical location. When portions of systems or plants are completed at different times, the jurisdiction of this Section shall cover only those components on which all construction related to the components has been completed.

ISTA-1300 Application

ISTA-1310 Components Subject to Testing and Examination. Components identified in Section IST for testing or examination shall be included in the test plan (para. ISTA-3110). These components include nuclear power plant items such as pumps, valves, and dynamic restraints (snubbers).

ISTA-1320 Classifications. Optional construction of a component in a system boundary to a classification higher than the minimum class established in the component Design Specification (either upgrading from Class 2 to Class 1 or Class 3 to Class 2) shall not affect the overall system classification by which the applicable requirements of Section IST are determined.

ISTA-1400 Referenced Standards and Specifications

When standards and specifications are referenced in Section IST, their revision date or indicator shall be as shown in Table ISTA-1400-1.

ISTA-1500 Owner's Responsibilities

The responsibilities of the Owner of the nuclear power plant shall include the following:

(a) determination of the appropriate Code Class for each component of the plant, identification of the system boundaries for each class of components subject to test or examination, and the components exempt from testing or examination requirements.

(b) design and arrangement of system components to include allowance for adequate access and clearances for conduct of the tests and examinations. Refer to Nonmandatory Appendix M of this Division for guidance.

(c) preparation of plans and schedules.

(d) preparation of written test and examination instructions and procedures.

(e) qualification of personnel who perform and evaluate examinations and tests in accordance with the Owner's quality assurance program.

(f) performance of required tests and examinations.

(g) recording of required test and examination results that provide a basis for evaluation and facilitate comparison with the results of subsequent tests or examinations.

(h) evaluation of tests and examination results.

(i) maintenance of adequate test and examination records such as test and examination data and description of procedures used.

(j) retention of all test and examination records for the service lifetime of the component or system.

(k) documentation of a quality assurance program in accordance with either of the following:

(1) Title 10, Code of Federal Regulations, Part 50

(2) ASME NQA-1, Parts II and III

ISTA-1600 Accessibility

Provisions for examination shall include access for the examination personnel and equipment necessary to conduct the test or examination.

Table ISTA-1400-1 Referenced Standards and Specifications

Standard or Specification	Revision Date or Indicator
PTC 25	1994
API RP-527	3rd edition, 1991

(15) ## ISTA-2000 DEFINITIONS

cold shutdown outage: applies to each nonrefueling outage period in which the cold shutdown mode, as defined by plant technical specifications, is entered.

equipment dynamic restraint (snubber): device that provides restraint to a component or system during the sudden application of forces, but allows essentially free motion during thermal movement.

examination: observing, visual monitoring, or measuring to determine conformance to Owner-specified requirements.

exercising: demonstration based on direct visual or indirect positive indications that the moving parts of a component function.

inservice test: test to assess the operational readiness of a system, structure, or component after first electrical generation by nuclear heat.

instrument loop: two or more instruments or components working together to provide a single output.

instrument loop accuracy: accuracy of an instrument loop based on the square root of the sum of the squares of the inaccuracies of each instrument or component in the loop when considered separately. Alternatively, the allowable inaccuracy of the instrument loop may be based on the output for a known input into the instrument loop.

maintenance: replacement of parts, adjustments, and similar actions that do not change the design (configuration and material) of an item.

modification: alteration in the design of a system, structure, or component.

monitoring: continuous or periodic observation or measurement to ascertain the performance or obtain characteristics of a system, structure, or component.

nonintrusive testing: testing performed on a component without disassembly or disturbing the boundary of the component.

obturator: valve closure member (disk, gate, plug, etc.).

operational readiness: the ability of a component to perform its specified functions.

overpressure protection: the means by which components are protected from overpressure by the use of pressure-relieving devices or other design provisions as required by the BPV Code, Section III, or other applicable construction codes.

Owner: an organization owning or operating a facility where items are installed or used.

performance testing: a test to determine whether a system or component meets specified acceptance criteria.

plant operation: the conditions of startup, operation at power, hot standby, and reactor cooldown, as defined by plant technical specifications.

post-2000 plant: a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

pre-2000 plant: a nuclear power plant that was issued its construction permit, or combined license for construction and operation, by the applicable regulatory authority prior to January 1, 2000.

preservice test: test performed after completion of construction activities related to the component and before first electrical generation by nuclear heat, or in an operating plant, before the component is initially placed in service.

preservice test period: the period of time following completion of construction activities related to the component and before first electrical generation by nuclear heat, in which component and system testing takes place, or in an operating plant prior to the component being initially placed in service.

pump: a mechanical device used to move fluid.

qualitative testing: testing performed to establish parameters without determining the specific measure of the parameter.

quantitative testing: testing performed to establish the specific measure or limit of a parameter, such as that required to establish that a parameter is within a specified range.

reference point: a point of operation at which reference values are established and inservice test parameters are measured for comparison with applicable acceptance criteria.

reference values: one or more values of parameters as measured or determined when the equipment is known to be operating acceptably.

refueling outage: applies to the normally scheduled once-per-cycle outage period in which the refueling mode, as defined by plant technical specifications, is entered.

repair: the process of restoring a degraded item to its original design requirements.

routine servicing: performance of planned, preventive maintenance.

skid-mounted pumps and valves: pumps and valves integral to or that support operation of major components, even though these pumps and valves may not be located directly on the skid. In general, these pumps and valves are supplied by the manufacturer of the major component. Examples include

(a) diesel fuel oil pumps and valves

(b) steam admission and trip throttle valves for high-pressure coolant injection turbine-driven pumps

(c) steam admission and trip throttle valves for auxiliary feedwater turbine-driven pumps

(d) solenoid-operated valves provided to control an air-operated valve

system resistance: hydraulic resistance to flow.

trending: a comparison of current data to previous data obtained under similar conditions for the same equipment.

valves, active: valves that are required to change obturator position to accomplish a specific function in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, or mitigating the consequences of an accident.

valves, passive: valves that maintain obturator position and are not required to change obturator position to accomplish the required function(s) in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, or mitigating the consequences of an accident.

ISTA-3000 GENERAL REQUIREMENTS

ISTA-3100 Test and Examination Program

ISTA-3110 Test and Examination Plans. Test plans shall be prepared for the preservice test period, initial inservice, and subsequent inservice test intervals.[1] Each inservice test plan shall include the following:

(a) the edition and addenda of this Section that apply to the required tests and examinations

(b) the classification of the components and the boundaries of system classification

(c) identification of the components subject to tests and examination

(d) the Code requirements for each component and the test or examination to be performed

(e) the Code requirements for each component that are not being satisfied by the tests or examinations; and justification for substitute tests or examinations

(f) Code Cases proposed for use and the extent of their application

(g) test or examination frequency or a schedule for performance of tests and examinations, as applicable

ISTA-3120 Inservice Examination and Test Interval

(a) Examination and test frequency shall be in accordance with the requirements of Section IST.

(b) The examination and test interval shall be determined by calendar years following placement of the unit into commercial service.

(c) The examination and test intervals shall comply with the following, except as modified by subparas. (d) and (e):

(1) Initial Examination and Test Interval: 10 yr following initial start of unit commercial service

(2) Successive Examination and Test Intervals: 10 yr following the previous test interval

(d) Each of the inservice examination and test intervals may be extended or decreased by as much as 1 yr. Adjustments shall not cause successive intervals to be altered by more than 1 yr from the original pattern of intervals.

(e) In addition to subpara. (d), for units that are out of service continuously for 6 months or more, the examination and test interval during which the outage occurred may be extended for a period equivalent to the outage and the original pattern of intervals extended accordingly for successive intervals.

(f) The inservice examination and test intervals for component replacements, additions, and alterations that may be required during the service lifetime of the unit shall coincide with the remaining intervals, as determined by the calendar years of unit service at the time of replacement, addition, or alteration.

ISTA-3130 Application of Code Cases

(a) Code Cases to be used during a preservice or inservice test or examination shall be identified in the test plan.

(b) Code Cases shall be applicable to the edition and addenda specified in the test plan.

(c) Code Cases shall be in effect at the time the test plan is filed, except as provided in subpara. (d).

(d) Code Cases issued subsequent to filing the test plan may be proposed for use in amendments to the test plan.

ISTA-3140 Application of Revised Code Cases. Superseded Code Cases approved for use in accordance with para. ISTA-3130 may continue to be used.

ISTA-3150 Application of Annulled Code Cases. Code Cases approved for use in accordance with para. ISTA-3130 or ISTA-3140 may be used after annulment for the duration of that test plan.

ISTA-3160 Test and Examination Procedures. Tests and examinations shall be performed in accordance with written procedures. The procedures shall contain the Owner-specified reference values and acceptance criteria.

ISTA-3200 Administrative Requirements

(a) IST Plans shall be filed with the regulatory authorities having jurisdiction at the plant site.

[1] Guidance for the preparation of test plans is in Nonmandatory Appendix A of this Division.

(b) The selection of components included in the test plan is subject to review by the regulatory authorities having jurisdiction at the plant site.

(c) Application of the requirements of this Section shall be governed by group classification criteria of the regulatory authority having jurisdiction at the plant site.

(d) The use of any Code Case is subject to acceptance by the regulatory authorities having jurisdiction at the plant site.

(e) Revisions to a previously approved Code Case may be substituted for that Code Case with the acceptance of the regulatory authorities having jurisdiction at the plant site.

(f) Tests and examinations shall meet the requirements of the edition and addenda of this Section specified in the following paragraphs:

(1) *Preservice Test Period.* The test plan for the preservice test period shall comply with the latest edition and addenda of this Section that have been adopted by the regulatory authority 36 months prior to the docket date of the unit's construction permit, or the edition and addenda of the OM Code referenced in the unit's Combined License, as applicable. Alternatively, the test plan for the preservice test period shall comply with subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions and addenda may be used, provided all related requirements are met.

(2) *Initial Inservice Test Interval.* The test plan for the initial inservice test interval shall comply with the latest edition and addenda of the Section that have been adopted by the regulatory authority 12 months prior to the issuance of the operating license, or 12 months before the date scheduled for the initial loading of fuel under a Combined License, as applicable. Alternatively, the test plan for the initial inservice test interval shall comply with subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions or addenda may be used, provided all related requirements are met.

(3) *Successive Inservice Test Intervals.* The test plan for each successive inservice test interval shall comply with the edition and addenda of the Section that have been adopted by the regulatory authority 12 months prior to the start of the inservice test interval, or subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions or addenda may be used, provided all related requirements are met.

ISTA-3300 Corrective Actions

Corrective actions requiring repair/replacement activities shall be performed in accordance with ASME Section XI, as applicable. Other corrective actions shall be performed in accordance with the Owner's quality assurance program.

ISTA-4000 INSTRUMENTATION AND TEST EQUIPMENT

ISTA-4100 Range and Accuracy

Instrumentation and test equipment used in performing the examination and testing program shall have the range and accuracy necessary to demonstrate conformance to specific examination or test requirements.

ISTA-4200 Calibration

All instruments and test equipment used in performing the examination and testing program shall be calibrated and controlled in accordance with the Owner's administrative procedures or a quality assurance program approved by the Owner.

ISTA-5000 TO BE PROVIDED AT A LATER DATE

ISTA-6000 TO BE PROVIDED AT A LATER DATE

ISTA-7000 TO BE PROVIDED AT A LATER DATE

ISTA-8000 TO BE PROVIDED AT A LATER DATE

ISTA-9000 RECORDS AND REPORTS

ISTA-9100 Scope

The requirements for retention of records apply to those records generated in the course of performing preservice and inservice tests and examinations required by Section IST.

ISTA-9200 Requirements

ISTA-9210 Owner's Responsibility

(a) The Owner shall prepare plans for preservice and inservice tests and examinations to meet the requirements of Section IST.

(b) The Owner shall prepare and retain records of the preservice and inservice tests and examinations.

ISTA-9220 Preparation

(a) Test and examination records shall be prepared in accordance with the requirements of the Subsection applicable to the test and examination requirements.

(b) Plans shall have a cover sheet providing the following information:

(1) date of document completion
(2) name and address of Owner
(3) name and address of plant
(4) name and number designation of the unit
(5) commercial service date for the unit

ISTA-9230 Inservice Test and Examination Results. The results of tests and examinations shall be documented and shall include the following, as a minimum:

(a) component identification
(b) date of test or examination
(c) reason for test or examination (e.g., postmaintenance, routine inservice test or examination, establishing reference values, etc.)

(d) test or examination procedure used
(e) identification of test equipment used
(f) calibration records, or traceability to calibration records
(g) values of measured parameters
(h) comparison with allowable ranges of test and examination values, and analysis of deviations
(i) requirement for corrective action
(j) documentation of the person(s) responsible for conducting and analyzing the test or examination per the Owner's QA program

ISTA-9240 Record of Corrective Actions. The Owner shall maintain records of corrective action that shall include a summary of the corrective actions made, the subsequent inservice test or examination, confirmation of operational adequacy, and the printed (or typed) name and signature of the person(s) responsible for the corrective action and verification of results.

ISTA-9300 Retention

ISTA-9310 Maintenance of Records. The Owner shall retain records identified in para. ISTA-9330 as a minimum. The records shall be filed and maintained. The Owner shall provide suitable protection from deterioration and damage for all records, in accordance with the Owner's quality assurance program for the service lifetime of the component or system. Storage shall be either at the plant site or at another location that will meet the access and quality assurance program requirements.

ISTA-9320 Reproduction. Records shall be either the original or a legible copy.

ISTA-9330 Test and Examination Records. The Owner shall be responsible for designating the records to be maintained. Such records shall include the following as a minimum:
(a) an index to record file
(b) test plans (see para. ISTA-3110)
(c) test and examination results
(d) records of corrective actions

Subsection ISTB
Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants — Pre-2000 Plants[1]

ISTB-1000 INTRODUCTION

ISTB-1100 Applicability

The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.

ISTB-1200 Exclusions

The following are excluded from this Subsection:

(a) drivers, except where the pump and driver form an integral unit and the pump bearings are in the driver

(b) pumps that are supplied with emergency power solely for operating convenience

(c) skid-mounted pumps that are tested as part of the major component and are justified by the Owner to be adequately tested

ISTB-1300 Pump Categories

All pumps within the scope of paras. ISTA-1100 and ISTB-1100 shall be categorized as either a Group A or Group B pump.

ISTB-1400 Owner's Responsibility

In addition to the requirements of para. ISTA-1500, the Owner's responsibility includes

(a) providing in both the pumps and plant design all necessary valving, instrumentation, test loops, required fluid inventory, or other provisions that are required to fully comply with the requirements of this Subsection.

(b) identifying each pump to be tested in accordance with the rules of this Subsection, categorizing the pump as either a Group A or Group B pump, and listing the pumps in the plant records (see section ISTB-9000). A pump that meets both Group A and Group B pump definitions shall be categorized as a Group A pump.

(c) establishing a comprehensive pump test flow rate for each pump.

(d) establishing a pump periodic verification test program[2] in accordance with Division 1, Mandatory Appendix V.

[1] *Pre-2000 plant:* a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

[2] Reference Division 1, Mandatory Appendix V, Pump Periodic Verification Test Program.

ISTB-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection.

comprehensive pump test flow rate: the flow rate established by the Owner that is effective for detecting mechanical and hydraulic degradation during subsequent testing. The best efficiency point, system flow rates, and any other plant-specific flow rates shall be considered.

Group A pumps: pumps that are operated continuously or routinely during normal operation, cold shutdown, or refueling operations.

Group B pumps: pumps in standby systems that are not operated routinely except for testing.

vertical line shaft pump: a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.

ISTB-3000 GENERAL TESTING REQUIREMENTS

The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action.

The parameters to be measured during preservice and inservice testing are specified in Table ISTB-3000-1.

ISTB-3100 Preservice Testing

During the preservice test period or before implementing inservice testing, an initial set of reference values shall be established for each pump. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Except as specified in para. ISTB-3310, only one preservice test is required for each pump. A set of reference values shall be established in accordance with para. ISTB-3300 for each pump required to be tested by this Subsection. Preservice testing shall be performed in accordance with the requirements of the following paragraphs:

(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTB-5110

(b) vertical line shaft centrifugal pump tests in accordance with para. ISTB-5210

Table ISTB-3000-1 Inserviсe Test Parameters

Quantity	Preservice Test	Group A Test	Group B Test	Comprehensive Test	Pump Periodic Verification Test [Note (1)]	Remarks
Speed, N	X	X	X	X	X	If variable speed
Differential pressure, ΔP	X	X	X [Note (2)]	X	X	Centrifugal pumps, including vertical line shaft pumps
Discharge pressure, P	X	X	. . .	X	X	Positive displacement pumps
Flow rate, Q	X	X	X [Note (2)]	X	X	. . .
Vibration	X	X	. . .	X	. . .	Measure either V_d or V_v
Displacement, V_d	. . .	. . .	. . .	. . .	. . .	Peak-to-peak
Velocity, V_v	. . .	. . .	. . .	. . .	. . .	Peak

NOTES:
(1) Only required for those pumps identified in Division 1, Mandatory Appendix V.
(2) For positive displacement pumps, flow rate shall be measured or determined; for all other pumps, differential pressure or flow rate shall be measured or determined.

(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTB-5310

(d) reciprocating positive displacement pump tests in accordance with para. ISTB-5310

ISTB-3200 Inservice Testing

Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see para. ISTB-1100). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:

(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTB-5120

(b) vertical line shaft centrifugal pump tests in accordance with para. ISTB-5220

(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTB-5320

(d) reciprocating positive displacement pump tests in accordance with para. ISTB-5320

ISTB-3300 Reference Values

Reference values shall be obtained as follows:

(a) Initial reference values shall be determined from the results of testing meeting the requirements of para. ISTB-3100, Preservice Testing, or from the results of the first inservice test.

(b) New or additional reference values shall be established as required by para. ISTB-3310 or ISTB-3320, or subpara. ISTB-6200(c).

(c) Reference values shall be established only when the pump is known to be operating acceptably.

(d) Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests.

(e) Reference values shall be established in a region(s) of relatively stable pump flow.

(1) Reference values shall be established at the comprehensive pump test flow rate for the comprehensive test.

(2) Reference values shall be established at the comprehensive pump test flow rate for the Group A and Group B tests, if practicable. If not practicable, the reference point flow rate shall be established at the highest practical flow rate.

(f) All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with para. ISTB-3310 or ISTB-3320, or subpara. ISTB-6200(c).

(g) Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with para. ISTB-6400.

ISTB-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values. When a reference value or set of values may have been affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with para. ISTB-3300 or the previous value reconfirmed by a comprehensive or Group A test run before declaring the pump operable. The Owner shall determine whether the requirements of para. ISTB-3100, to reestablish reference values, apply. Deviations between the previous and new set of reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see section ISTB-9000).

ISTB-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable, for some reason other than stated in para. ISTB-3310, to establish an additional set of reference values, a Group A or comprehensive test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is acceptable per para. ISTB-6200, an additional set of reference values may be established as follows:

(a) For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in para. ISTB-5110 or

Table ISTB-3400-1 Inservice Test Frequency

Pump Group	Group A Test	Group B Test	Comprehensive Test	Pump Periodic Verification Test [Note (1)]
Group A	Quarterly	N/A	Biennially	Biennially
Group B	N/A	Quarterly	Biennially	Biennially

GENERAL NOTE: N/A = Not applicable.

NOTE:

(1) Only required for those pumps identified in Division 1, Mandatory Appendix V.

Table ISTB-3510-1 Required Instrument Accuracy

Quantity	Group A and Group B Test, %	Comprehensive and Preservice Tests, %
Pressure	±2	$\pm\frac{1}{2}$
Flow rate	±2	±2
Speed	±2	±2
Vibration	±5	±5
Differential pressure	±2	$\pm\frac{1}{2}$

ISTB-5210, as applicable. Vibration acceptance criteria shall be established by a Group A or comprehensive test at the new reference point. If vibration data was taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable.

(b) For positive displacement pumps, the additional set of reference values shall be established per para. ISTB-5310.

A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTB-9000). The requirements of para. ISTB-3300 apply.

ISTB-3400 Frequency of Inservice Tests

An inservice test shall be run on each pump as specified in Table ISTB-3400-1.

ISTB-3410 Pumps in Regular Use. Group A pumps that are operated more frequently than every 3 months need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 months at the reference conditions, and the quantities specified were determined, recorded, and analyzed per section ISTB-6000.

ISTB-3420 Pumps in Systems Out of Service. For a pump in a system declared inoperable or not required to be operable, the test schedule need not be followed. Within 3 months before the system is placed in an operable status, the pump shall be tested and the test schedule followed in accordance with the requirements of this Subsection. Pumps that can only be tested during plant operation shall be tested within 1 week following plant startup.

ISTB-3430 Pumps Lacking Required Fluid Inventory. Group B pumps lacking required fluid inventory (e.g., pumps in dry sumps) shall receive a comprehensive test at least once every 2 yr except as provided in para. ISTB-3420. The required fluid inventory shall be provided during this test. A Group B test is not required.

ISTB-3500 Data Collection

ISTB-3510 General

(a) Accuracy. Instrument accuracy shall be within the limits of Table ISTB-3510-1. If a parameter is determined by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of Table ISTB-3510-1 (e.g., flow rate determination shall be accurate to within ±2% of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.

(b) Range

(1) The full-scale range of each analog instrument shall be not greater than three times the reference value.

(2) Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument.

(3) Vibration instruments are excluded from the range requirements of subparas. (b)(1) and (b)(2).

(c) Instrument Location. The sensor location shall be established by the Owner, documented in the plant records (see section ISTB-9000), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be either permanently mounted, or provision shall be made to duplicate their position during each test.

(d) Fluctuations. Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines.

(e) Frequency Response Range. The frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.

ISTB-3520 Pressure

(a) Gage Lines. If the presence or absence of liquid in a gage line could produce a difference of more than 0.25% in the indicated value of the measured pressure, means shall be provided to ensure or determine the

presence or absence of liquid as required for the static correction used.

(b) Differential Pressure. When determining differential pressure across a pump, a differential pressure gage or a differential pressure transmitter that provides direct measurement of the pressure difference or the difference between the pressure at a point in the inlet and the pressure at a point in the discharge pipe shall be used.

ISTB-3530 Rotational Speed. Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of para. ISTB-3510.

ISTB-3540 Vibration

(a) On centrifugal pumps, except vertical line shaft pumps, measurements shall be taken in a plane approximately perpendicular to the rotating shaft in two approximately orthogonal directions on each accessible pump-bearing housing. Measurement shall also be taken in the axial direction on each accessible pump thrust bearing housing.

(b) On vertical line shaft pumps, measurements shall be taken on the upper motor-bearing housing in three approximately orthogonal directions, one of which is the axial direction.

(c) On reciprocating pumps, the location shall be on the bearing housing of the crankshaft, approximately perpendicular to both the crankshaft and the line of plunger travel.

(d) If a portable vibration indicator is used, the measurement points shall be clearly identified on the pump to permit subsequent duplication in both location and plane.

ISTB-3550 Flow Rate. When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. External recirculated flow is not required to be measured if it is not practical to isolate, has a fixed resistance, and has been evaluated by the Owner to not have a substantial effect on the results of the test.

ISTB-4000 TO BE PROVIDED AT A LATER DATE

ISTB-5000 SPECIFIC TESTING REQUIREMENTS

This Subsection defines requirements for preservice, Group A, Group B, and comprehensive tests.

(a) When a Group B test is required, a Group A, comprehensive, or preservice test may be substituted.

(b) When a Group A test is required, a comprehensive or preservice test may be substituted.

(c) When a comprehensive test is required, a preservice test may be substituted.

ISTB-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps)

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by Table ISTB-3000-1 shall be made and recorded.

(b) Bypass Loops

(1) A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300.

(2) A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5110 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1.

(a) In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least the comprehensive pump test flow rate. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTB-5120 Inservice Testing

ISTB-5121 Group A Test Procedure. Group A tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed +2% or −1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point

Table ISTB-5121-1 Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test [Notes (1), (2)]	N/A	Q	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	0.90 to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q, or	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	0.90 to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.94 to $1.06Q_r$	0.90 to $<0.94Q_r$	$<0.90Q_r$	$>1.06Q_r$
	N/A	ΔP	0.93 to $1.06\Delta P_r$	0.90 to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript *r* denotes reference value, the subscript *v* denotes vibration velocity reference value, and the subscript *d* denotes displacement.

NOTES:

(1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.

(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

with the variance not to exceed +1% or −2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5121-1 and corrective action taken as specified in para. ISTB-6200. Vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5121-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s) the pump is in the required action range.

ISTB-5122 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameter value identified in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The differential pressure or flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a point as close as practical to the reference point. If the reference point is flow rate, the variance from the reference point shall not exceed +2% or −1%. If the reference point is differential pressure, the variance from the reference point shall not exceed +1% or −2% of the reference point.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTB-5121-1 and corrective action taken as specified in para. ISTB-6200.

ISTB-5123 Comprehensive Test Procedure. Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed +2% or −1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5121-1 and corrective action taken as specified in para. ISTB-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5121-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5200 Vertical Line Shaft Centrifugal Pumps

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by Table ISTB-3000-1 shall be made and recorded.

(b) Bypass Loops

(1) A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300.

(2) A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5210 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1.

(a) In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least the comprehensive pump test flow rate. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTB-5220 Inservice Testing

ISTB-5221 Group A Test Procedure. Group A tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed +2% or −1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5221-1 and corrective action taken as specified in para. ISTB-6200. Vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5221-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5222 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this

Table ISTB-5221-1 Vertical Line Shaft Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test [Notes (1), (2)]	N/A	Q	0.95 to $1.10Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	ΔP	0.95 to $1.10\Delta P_r$	0.93 to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.10\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q, or	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	Δp	0.90 to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.95 to $1.06Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	ΔP	0.95 to $1.06\Delta P_r$	0.93 to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

(1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.

(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

paragraph. The test parameter value identified in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The differential pressure or flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a point as close as practical to the reference point. If the reference point is flow rate, the variance from the reference point shall not exceed +2% or −1%. If the reference point is differential pressure, the variance from the reference point shall not exceed +1% or −2% of the reference point.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTB-5221-1 and corrective action taken as specified in para. ISTB-6200.

ISTB-5223 Comprehensive Test Procedure. Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

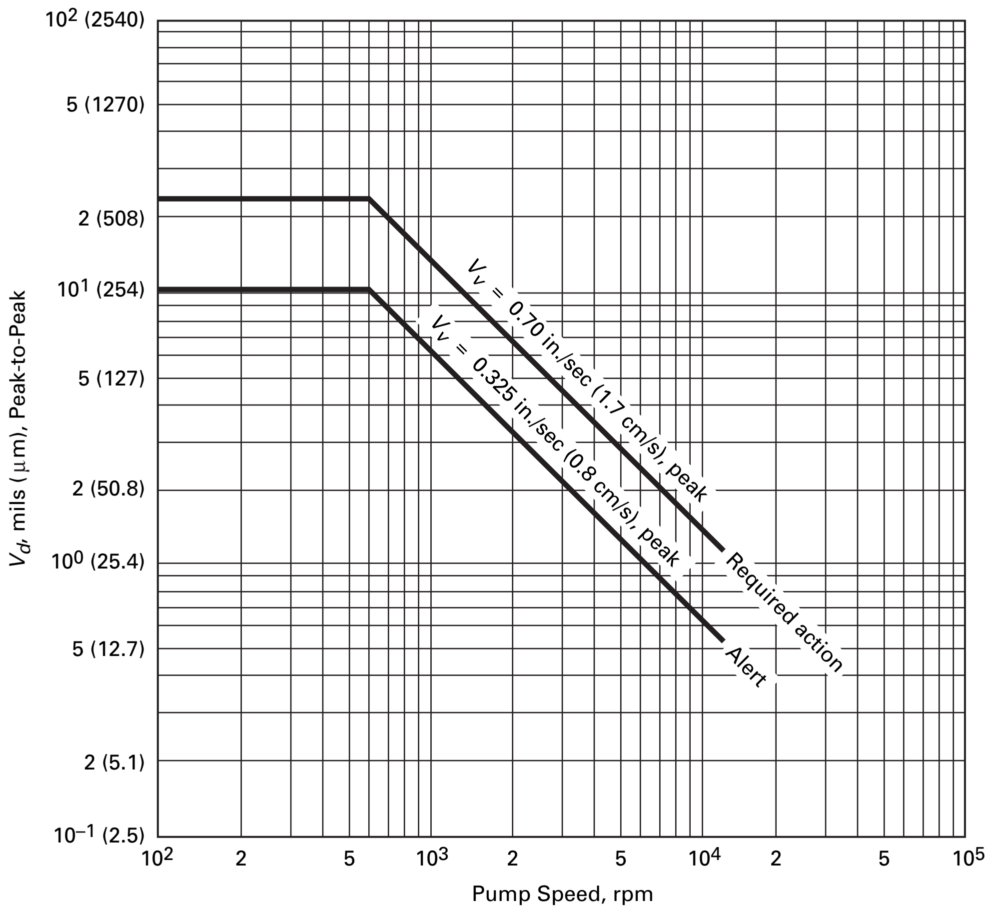
(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed +2% or −1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See Fig. ISTB-5223-1.)

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5221-1 and

Fig. ISTB-5223-1 Vibration Limits



corrective action taken as specified in para. ISTB-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5221-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5300 Positive Displacement Pumps

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by Table ISTB-3000-1 shall be made and recorded.

(b) Bypass Loops. A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300. A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5310 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1.

(a) For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in Table ISTB-3000-1.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTB-5320 Inservice Testing

ISTB-5321 Group A Test Procedure. Group A tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

Table ISTB-5321-1 Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test [Notes (1), (2)]	N/A	Q	0.95 to $1.10Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	P	0.93 to $1.10P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.10P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$<2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.95 to $1.06Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	P	0.93 to $1.06P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.06P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:
(1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.
(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

(b) The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in para. ISTB-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTB-5321-2. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5321-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5322 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameter value identified in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a point as close as practical to the reference point. The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in para. ISTB-6200.

ISTB-5323 Comprehensive Test Procedure. Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference

Table ISTB-5321-2 Reciprocating Positive Displacement Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test	N/A	Q	0.95 to $1.10Q_r$	0.93 to $< 0.95Q_r$	$< 0.93Q_r$	$> 1.10Q_r$
	N/A	P	0.93 to $1.10P_r$	0.90 to $< 0.93P_r$	$< 0.90P_r$	$> 1.10P_r$
	N/A	V_d or V_v	$\leq 2.5V_r$	$> 2.5V_r$ to $6V_r$	None	$> 6V_r$
Group B Test	N/A	Q	0.90 to $1.10Q_r$	None	$< 0.90Q_r$	$> 1.10Q_r$
Comprehensive Test	N/A	Q	0.95 to $1.06Q_r$	0.93 to $< 0.95Q_r$	$< 0.93Q_r$	$> 1.06Q_r$
	N/A	P	0.93 to $1.06P_r$	0.90 to $< 0.93P_r$	$< 0.90P_r$	$> 1.06P_r$
	N/A	V_d or V_v	$\leq 2.5V_r$	$> 2.5V_r$ to $6V_r$	None	$> 6V_r$

GENERAL NOTE: The subscript *r* denotes reference value, the subscript *v* denotes vibration velocity reference value, and the subscript *d* denotes displacement.

point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed +1% or −2% of the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in para. ISTB-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTB-5321-1. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5321-2. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-6000 MONITORING, ANALYSIS, AND EVALUATION

ISTB-6100 Trending

Test parameters shown in Table ISTB-3000-1, except for fixed values, shall be trended.

ISTB-6200 Corrective Action

(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the frequency of testing specified in para. ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. (c).

(b) Action Range. If the measured test parameter values fall within the required action range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. (c).

(c) Analysis. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, an analysis may be performed that supports the pump's continued use at the changed values. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The analysis shall also consider whether new reference values should be established and shall justify the adequacy of

the new reference values, if applicable. The results of this analysis shall be documented in the record of tests (see section ISTB-9000).

ISTB-6300 Systematic Error

When a test shows measured parameter values that fall outside of the acceptable range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.

ISTB-6400 Analysis of Related Conditions

If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed[3] and documented in the record of tests (see section ISTB-9000).

[3] Vibration measurements of pumps may be foundation, driver, or piping dependent. Therefore, if initial vibration readings are high and have no obvious relationship to the pump, then vibration measurements should be taken at the driver, at the foundation, and on the piping and analyzed to ensure that the reference vibration measurements are representative of the pump and the measured vibration levels will not prevent the pump from fulfilling its function.

ISTB-7000 TO BE PROVIDED AT A LATER DATE

ISTB-8000 TO BE PROVIDED AT A LATER DATE

ISTB-9000 RECORDS AND REPORTS

ISTB-9100 Pump Records

The Owner shall maintain a record that shall include the following for each pump covered by this Subsection:

(a) the manufacturer and the manufacturer's model and serial or other identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) a copy of the pump manufacturer's operating limits

(d) the comprehensive pump test flow rate basis (e.g., flow rate and associated differential or discharge pressure and speed for variable speed pumps)

ISTB-9200 Test Plans

In addition to the requirements of paras. ISTA-3110 and ISTA-3160, the test plans and procedures shall include the following:

(a) category of each pump

(b) the hydraulic circuit to be used

(c) the location and type of measurement for the required test parameters

(d) the method of determining test parameter values that are not directly measured by instrumentation

ISTB-9300 Record of Tests

See para. ISTA-9230.

ISTB-9400 Record of Corrective Action

See para. ISTA-9240.

Subsection ISTC Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants

ISTC-1000 INTRODUCTION

ISTC-1100 Applicability

The requirements of this Subsection apply to certain valves and pressure relief devices (and their actuating and position-indicating systems).

ISTC-1200 Exemptions

The following components are excluded from the testing requirements of this Subsection, provided that the components are not required to perform a specific function as described in para. ISTA-1100:

(a) valves used only for operating convenience such as vent, drain, instrument, and test valves

(b) valves used only for system control, such as pressure-regulating valves

(c) valves used only for system or component maintenance

Skid-mounted valves are excluded from this Subsection, provided they are tested as part of the major component and are justified by the Owner to be adequately tested.

External control and protection systems responsible for sensing plant conditions and providing signals for valve operation are excluded from the requirements of this Subsection.

Category A and Category B safety and relief valves are excluded from the requirements of para. ISTC-3500, Valve Testing Requirements and para. ISTC-3700, Position Verification Testing.

Nonreclosing pressure relief devices (rupture disks) used in BWR Scram Accumulators are excluded from the requirements of this Subsection.

ISTC-1300 Valve Categories

Valves within the scope of this Subsection shall be placed in one or more of the following categories. Where specified in Table ISTC-3500-1, when more than one distinguishing category characteristic is applicable, all requirements of each of the individual categories are applicable, although duplication or repetition of common testing requirements is not necessary.

(a) Category A: valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their required function(s), as specified in para. ISTA-1100.

(b) Category B: valves for which seat leakage in the closed position is inconsequential for fulfillment of the required function(s), as specified in para. ISTA-1100.

(c) Category C: valves that are self-actuating in response to some system characteristic, such as pressure (relief valves) or flow direction (check valves) for fulfillment of the required function(s), as specified in para. ISTA-1100.

(d) Category D: valves that are actuated by an energy source capable of only one operation, such as rupture disks or explosively actuated valves.

ISTC-1400 Owner's Responsibility

In addition to the requirements of para. ISTA-1500, it is the Owner's responsibility to

(a) include in the plant design all necessary instrumentation, test connections, flow instruments, or any other provisions that are required to fully comply with the requirements of this Subsection.

(b) categorize (see para. ISTC-1300), and list in the plant records (see section ISTC-9000) each valve to be tested in accordance with the rules of this Subsection, including Owner-specified acceptance criteria. The Owner shall specify test conditions.

(c) ensure that the application, method, and capability of each nonintrusive technique is qualified.

ISTC-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection:

full-stroke time: the time interval from initiation of the actuating signal to the indication of the end of the operating stroke.

power-operated relief valve (PORV): a power-operated valve that can perform a pressure-relieving function and is remotely actuated by either a signal from a pressure-sensing device or a control switch. A power-operated relief valve is not capacity certified under ASME Section III overpressure protection requirements.

reactor coolant system pressure isolation: that function that prevents intersystem overpressurization between the reactor coolant system and connected low pressure systems.

ISTC-3000 GENERAL TESTING REQUIREMENTS

ISTC-3100 Preservice Testing

Each valve shall be tested during the preservice test period as required by this Subsection. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Only one preservice test of each valve is required with these exceptions.

(a) Any valve that has undergone maintenance that could affect its performance after the preservice test shall be tested in accordance with para. ISTC-3310.

(b) Safety and relief valves and nonreclosing pressure relief devices shall meet the preservice test requirements of Mandatory Appendix I of this Division.

(c) Active motor-operated valves (MOV) shall meet the preservice test requirements of Mandatory Appendix III of this Division.

(d) For post-2000 plants, Category D explosively actuated valves shall be preservice tested as follows:

(1) Verify the operational readiness of the actuation logic and associated electrical circuits for each valve with its pyrotechnic charge removed from the valve. This must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available at the valve from each circuit that is relied upon to actuate the valve.

(2) Select a sample of at least 20% of the pyrotechnic charges in all valves to be tested. Test each selected charge either in the valve or a qualified test fixture to confirm the capability of each sampled charge to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping. The sampling must include at least one explosively actuated valve from each redundant safety train.

(3) Resolve any deficiencies identified in the operational readiness of the actuation logic or associated electrical circuits or the capability of a pyrotechnic charge. If a charge fails to fire or its capability is not confirmed, all charges with the same batch number shall be removed, discarded, and replaced with charges from a different batch number that has demonstrated successful 20% sampling of the charges.

ISTC-3200 Inservice Testing

Inservice testing in accordance with this Subsection shall commence when the valves are required to be operable to fulfill their required function(s) (see para. ISTA-1100).

ISTC-3300 Reference Values

Reference values shall be determined from the results of preservice testing or from the results of inservice testing. These tests shall be performed under conditions as near as practicable to those expected during subsequent inservice testing.

Reference values shall be established only when the valve is known to be operating acceptably. If the particular parameter being measured can be significantly influenced by other related conditions, then these conditions shall be analyzed.

ISTC-3310 Effects of Valve Repair, Replacement, or Maintenance on Reference Values. When a valve or its control system has been replaced, repaired, or has undergone maintenance[1] that could affect the valve's performance, a new reference value shall be determined or the previous value reconfirmed by an inservice test run before the time it is returned to service or immediately if not removed from service. This test is to demonstrate that performance parameters that could be affected by the replacement, repair, or maintenance are within acceptable limits. Deviations between the previous and new reference values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented in the record of tests (see para. ISTC-9120). Safety and relief valves and nonreclosing pressure relief devices shall be tested as required by the replacement, repair, and maintenance requirements of Mandatory Appendix I of this Division.

Active MOVs shall be tested as required by the replacement, repair, and maintenance requirements of Mandatory Appendix III of this Division.

ISTC-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable for some reason, other than stated in para. ISTC-3310, to establish additional reference values, an inservice test shall first be run at the conditions of an existing set of reference values, or, if impractical, at the conditions for which the new reference values are required, and the results analyzed. If operation is acceptable in accordance with the applicable requirements of para. ISTC-5100, a second test shall be performed under the new conditions as soon as practicable. The results of the second test shall establish the additional reference values. Whenever additional reference values are established, the reasons for doing so shall be justified and documented in the record of tests (see para. ISTC-9120).

ISTC-3400 To Be Provided at a Later Date

ISTC-3500 Valve Testing Requirements

Active and passive valves in the categories defined in para. ISTC-1300 shall be tested in accordance with the paragraphs specified in Table ISTC-3500-1 and the applicable requirements of paras. ISTC-5100 and ISTC-5200.

ISTC-3510 Exercising Test Frequency. Active Category A, Category B, and Category C check valves

[1] Adjustment of stem packing, limit switches, or control system valves, and removal of the bonnet, stem assembly, actuator, obturator, or control system components are examples of maintenance that could affect valve performance parameters.

Table ISTC-3500-1 Inservice Test Requirements

Category (See ISTC-1300)	Valve Function	Leakage Test Procedure and Frequency	Exercise Test Procedure and Frequency	Special Test Procedure [Note (1)]	Position Indication Verification and Frequency
A [Notes (1), (2)]	Active	See para. ISTC-3600	See para. ISTC-3510 [Note (3)]	None	See para. ISTC-3700 [Note (3)]
A [Note (2)]	Passive	See para. ISTC-3600	None	None	See para. ISTC-3700
B [Notes (1), (2)]	Active	None	See para. ISTC-3510 [Note (3)]	None	See para. ISTC-3700 [Note (3)]
B [Note (2)]	Passive	None	None	None	See para. ISTC-3700
C (safety and relief) [Notes (2), (4)]	Active	None	See paras. ISTC-5230, ISTC-5240	None	See para. ISTC-3700
C (check valve) [Notes (2), (5)]	Active	None	See para. ISTC-3510	None	See para. ISTC-3700
D	Active	None	None	See paras. ISTC-5250, ISTC-5260	None

NOTES:
(1) Note additional requirement for fail-safe valves, para. ISTC-3560.
(2) When more than one distinguishing category characteristic is applicable, all requirements of each of the individual categories are applicable, although duplication or repetition of common testing requirements is not necessary.
(3) For active MOVs, see Mandatory Appendix III of this Division per para. ISTC-5120.
(4) Leak test as required for Mandatory Appendix I.
(5) If a check valve used for a pressure relief device is capacity certified, then it shall be classified as a pressure or vacuum relief device. If a check valve used to limit pressure is not capacity certified, then it shall be classified as a check valve.

shall be exercised nominally every 3 months, except as provided by paras. ISTC-3520, ISTC-3540, ISTC-3550, ISTC-3570, ISTC-5221, and ISTC-5222. Power-operated relief valves shall be exercise tested once per fuel cycle.

ISTC-3520 Exercising Requirements

(15) **ISTC-3521 Category A and Category B Valves.** Category A and Category B valves shall be tested as follows:

(a) full-stroke exercising of Category A and Category B valves during operation at power to the position(s) required to fulfill its function(s).

(b) if full-stroke exercising during operation at power is not practicable, it may be limited to part-stroke during operation at power and full-stroke during cold shutdown outages.

(c) if exercising is not practicable during operation at power, it may be limited to full-stroke exercising during cold shutdown outages.

(d) if exercising is not practicable during operation at power and full-stroke during cold shutdown outages is also not practicable, it may be limited to part-stroke during cold shutdown outages, and full-stroke during refueling outages.

(e) if exercising is not practicable during operation at power or cold shutdown outages, it may be limited to full-stroke during refueling outages.

(f) valves exercised during cold shutdown outages shall be exercised during each cold shutdown outage, except as specified in subpara. (g). Such exercise is not required if the time period since the previous exercise is less than 3 months. During extended shutdowns, valves that are required to perform their intended function (see para. ISTA-1100) shall be exercised every 3 months, if practicable.

(g) valve exercising during cold shutdown outages shall commence within 48 hr of achieving the cold shutdown mode and continue until all testing is complete, with the following exceptions:

(1) The plant is ready to return to operation at power.

(2) For extended outages, testing need not be commenced within 48 hr, provided all valves required to be tested during cold shutdown outages will be tested before or as part of plant startup.

(3) For shorter duration outages, tests not completed in previous cold shutdown outage(s) should be preferentially selected for testing during subsequent cold shutdown outage(s) as plant conditions allow.

(4) As appropriate, valves may be tested upon the commencement of power reduction, while decreasing plant modes to the cold shutdown mode, during the cold shutdown mode, or while increasing plant modes to operation at power.

(5) If in the cold shutdown mode for less than 48 hr, no cold shutdown outage testing is required to be completed.

(h) all valve testing required to be performed during a refueling outage may begin upon the commencement

of power reduction, as appropriate, but shall be completed before returning the plant to operation at power.

(15) **ISTC-3522 Category C Check Valves.** Category C check valves shall be exercised as follows:

(a) During operation at power, each check valve shall be exercised or examined in a manner that verifies obturator travel by using the methods in para. ISTC-5221.

Each check valve exercise test shall include open and close tests. Open and close tests need only be performed at an interval when it is practicable to perform both tests. Test order (e.g., whether the open test precedes the close test) shall be determined by the Owner. Open and close tests are not required to be performed at the same time if they are both performed within the same interval.

(b) If exercising is not practicable during operation at power, it shall be performed during cold shutdown outages.

(c) If exercising is not practicable during operation at power and cold shutdown outages, it shall be performed during refueling outages.

(d) Valves exercised during cold shutdown outages shall be exercised during each cold shutdown, except as specified in subpara. (e). Such exercise is not required if the interval since the previous exercise is less than 3 months. During extended shutdowns, valves that are required to perform their intended function (see para. ISTA-1100) shall be exercised every 3 months, if practicable.

(e) Valve exercising during cold shutdown outages shall commence within 48 hr of achieving the cold shutdown mode and continue until all testing is complete, with the following exceptions:

(1) The plant is ready to return to operation at power.

(2) For extended outages, testing need not be commenced within 48 hr, provided all valves required to be tested during cold shutdown outages will be tested before or as part of plant startup.

(3) For shorter duration outages, tests not completed in previous cold shutdown outage(s) should be preferentially selected for testing during subsequent cold shutdown outage(s) as plant conditions allow.

(4) As appropriate, valves may be tested upon the commencement of power reduction, while decreasing plant modes to the cold shutdown mode, during the cold shutdown mode, or while increasing plant modes to operation at power.

(5) If in the cold shutdown mode for less than 48 hr, no cold shutdown outage testing is required to be completed.

(f) All valve testing required to be performed during a refueling outage may begin upon the commencement of power reduction, as appropriate, but shall be completed before returning the plant to operation at power.

ISTC-3530 Valve Obturator Movement. The necessary valve obturator movement shall be determined by exercising the valve while observing an appropriate indicator, such as indicating lights that signal the required changes of obturator position, or by observing other evidence, such as changes in system pressure, flow rate, level, or temperature, that reflects change of obturator position.

ISTC-3540 Manual Valves. Manual valves shall be full-stroke exercised at least once every 2 yr, except where adverse conditions[2] may require the valve to be tested more frequently to ensure operational readiness. Any increased testing frequency shall be specified by the Owner. The valve shall exhibit the required change of obturator position.

ISTC-3550 Valves in Regular Use. Valves that operate in the course of plant operation at a frequency that would satisfy the exercising requirements of this Subsection need not be additionally exercised, provided that the observations otherwise required for testing are made and analyzed during such operation and recorded in the plant record at intervals no greater than specified in para. ISTC-3510.

ISTC-3560 Fail-Safe Valves. Valves with fail-safe actuators shall be tested by observing the operation of the actuator upon loss of valve actuating power in accordance with the exercising frequency of para. ISTC-3510.

ISTC-3570 Valves in Systems Out of Service. For a valve in a system declared inoperable or not required to be operable, the exercising test schedule need not be followed. Within 3 months before placing the system in an operable status, the valves shall be exercised and the schedule followed in accordance with requirements of this Subsection.

ISTC-3600 Leak Testing Requirements

ISTC-3610 Scope of Seat Leakage Rate Test. Category A valves shall be leakage tested, except that valves that function in the course of plant operation in a manner that demonstrates functionally adequate seat leak-tightness need not be additionally leakage tested. In such cases, the valve record shall provide the basis for the conclusion that operational observations constitute satisfactory demonstration.

ISTC-3620 Containment Isolation Valves. Containment isolation valves with a leakage rate requirement based on Appendix J program commitment shall be tested in accordance with the Owner's 10 CFR 50, Appendix J program. Containment isolation valves with a leakage requirement based on other functions shall be

[2] Harsh service environment, lubricant hardening, corrosive or sediment-laden process fluid, or degraded valve components are some examples of adverse conditions.

tested in accordance with para. ISTC-3630. Examples of these other functions are reactor coolant system pressure isolation valves and certain Owner-defined system functions such as inventory preservation, system protection, or flooding protection.

ISTC-3630 Leakage Rate for Other Than Containment Isolation Valves. Category A valves with a leakage requirement not based on an Owner's 10 CFR 50, Appendix J program, shall be tested to verify their seat leakages within acceptable limits. Valve closure before seat leakage testing shall be by using the valve operator with no additional closing force applied.

(a) Frequency. Tests shall be conducted at least once every 2 yr.

(b) Differential Test Pressure. Valve seat tests shall be made with the pressure differential in the same direction as when the valve is performing its function, with the following exceptions:

(1) Globe-type valves may be tested with pressure under the seat.

(2) Butterfly valves may be tested in either direction, provided their seat construction is designed for sealing against pressure on either side.

(3) Double-disk gate valves may be tested by pressurizing between the disks.

(4) Leakage tests involving pressure differential lower than function pressure differentials are permitted in those types of valves in which service pressure will tend to diminish the overall leakage channel opening, as by pressing the disk into or onto the seat with greater force. Gate valves, check valves, and globe-type valves, having function pressure differential applied over the seat, are examples of valve applications satisfying this requirement. When leakage tests are made in such cases using pressures lower than function maximum pressure differential, the observed leakage shall be adjusted to the function maximum pressure differential value. The adjustment shall be made by calculation appropriate to the test media and the ratio between the test and function pressure differential, assuming leakage to be directly proportional to the pressure differential to the one-half power.

(5) Valves not qualifying for reduced pressure testing as defined above shall be tested at full maximum function pressure differential.

(c) Seat Leakage Measurement. Valve seat leakage shall be determined by one of the following methods:

(1) measuring leakage through a downstream telltale connection while maintaining test pressure on one side of the valve

(2) measuring the feed rate required to maintain test pressure in the test volume or between two seats of a gate valve, provided the total apparent leakage rate is charged to the valve or valve combination or gate valve seat being tested and the conditions required by subpara. (b) are satisfied

(3) determining leakage by measuring pressure decay in the test volume, provided the total apparent leakage rate is charged to the valve or valve combination or gate valve seat being tested and the conditions required by subpara. (b) are satisfied

(d) Test Medium. The test medium shall be specified by the Owner.

(e) Analysis of Leakage Rates. Leakage rate measurements shall be compared with the permissible leakage rates specified by the plant Owner for a specific valve or valve combination. If leakage rates are not specified by the Owner, the following rates shall be permissible:

(1) for water, $0.5D$ gal/min ($12.4d$ mL/s) or 5 gal/min (315 mL/s), whichever is less, at function pressure differential

(2) for air, at function pressure differential, $7.5D$ standard ft^3/day ($58d$ std. cc/min)

where
D = nominal valve size, in.
d = nominal valve size, cm

(f) Corrective Action. Valves or valve combinations with leakage rates exceeding the valves specified by the Owner per subpara. (e) shall be declared inoperable and either repaired or replaced. A retest demonstrating acceptable operation shall be performed following any required corrective action before the valve is returned to service.

ISTC-3700 Position Verification Testing

Valves with remote position indicators shall be observed locally at least once every 2 yr to verify that valve operation is accurately indicated. Where practicable, this local observation should be supplemented by other indications such as use of flow meters or other suitable instrumentation to verify obturator position. These observations need not be concurrent. Where local observation is not possible, other indications shall be used for verification of valve operation.

Position verification for active MOVs shall be tested in accordance with Mandatory Appendix III of this Division.

ISTC-3800 Instrumentation

Instrumentation accuracy shall be considered when establishing valve test acceptance criteria.

ISTC-4000 TO BE PROVIDED AT A LATER DATE

ISTC-5000 SPECIFIC TESTING REQUIREMENTS

ISTC-5100 Power-Operated Valves (POVs)

All valves shall be tested in accordance with the applicable requirements of section ISTC-3000, and as identified below, except for power-operated control valves that only have a fail-safe safety function.

For power-operated control valves that only have a fail-safe safety function, the requirements for valve stroke-time measurement testing, the associated stroke-time test acceptance criteria, and any corrective actions that would result from stroke-time testing need not be met. For these valves, all other applicable requirements of section ISTC-3000, and as identified below, shall be met.

ISTC-5110 Power-Operated Relief Valves (PORVs). Power-operated relief valves shall meet the requirements of para. ISTC-5100 for the specific Category B valve type and para. ISTC-5240 for Category C valves.

ISTC-5111 Valve Testing Requirements

(a) Testing shall be performed in the following sequence or concurrently. If testing in the following sequence is impractical, it may be performed out of sequence, and a justification shall be documented in the record of tests for each test or in the test plan:

(1) leakage testing

(2) stroke testing

(3) position indication testing

(b) The pressure-sensing device shall be calibrated in accordance with the Owner's quality assurance program.

ISTC-5112 Leak Testing. Seat tightness of the PORV shall be verified by leak testing in accordance with the requirements of Mandatory Appendix I of this Division.

ISTC-5113 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with para. ISTC-3500.

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) The stroke time of all valves shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see para. ISTC-9120), and an evaluation shall be made regarding need for corrective action.

(e) Stroke testing shall be performed during normal operating conditions for temperature and pressure if practicable.

ISTC-5114 Stroke Test Acceptance Criteria. Test results shall be compared to the reference values established in accordance with para. ISTC-3300, ISTC-3310, or ISTC-3320.

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than ±25% change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than ±50% change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from subpara. (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5115 Corrective Action

(a) If a valve fails the applicable leak test acceptance criteria, to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see subpara. ISTC-5113(b)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of para. ISTC-5114 shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see para. ISTC-9120).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see para. ISTC-9120).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5120 Motor-Operated Valves Active MOVs shall meet the requirements of Mandatory Appendix III of this Division.

ISTC-5130 Pneumatically Operated Valves

ISTC-5131 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with para. ISTC-3500.

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) The stroke time of all valves shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see para. ISTC-9120), and an evaluation shall be made regarding need for corrective action.

ISTC-5132 Stroke Test Acceptance Criteria. Test results shall be compared to the reference values established in accordance with para. ISTC-3300, ISTC-3310, or ISTC-3320.

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than ±25% change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than ±50% change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from subpara. (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5133 Stroke Test Corrective Action

(a) If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see subpara. ISTC-5131(b)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of para. ISTC-5132 shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see para. ISTC-9120).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see para. ISTC-9120).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5140 Hydraulically Operated Valves

ISTC-5141 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with para. ISTC-3500.

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) The stroke time of all valves shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see para. ISTC-9120), and an evaluation shall be made regarding need for corrective action.

ISTC-5142 Stroke Test Acceptance Criteria. Test results shall be compared to reference values established in accordance with para. ISTC-3300, ISTC-3310, or ISTC-3320.

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than ±25% change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than ±50% change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from subpara. (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5143 Stroke Test Corrective Action

(a) If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see subpara. ISTC-5141(b)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of para. ISTC-5142 shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see para. ISTC-9120).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see para. ISTC-9120).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5150 Solenoid-Operated Valves

ISTC-5151 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with para. ISTC-3500.

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) Stroke time shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see para. ISTC-9120), and an evaluation shall be made regarding need for corrective action.

ISTC-5152 Stroke Test Acceptance Criteria. Test results shall be compared to reference values established in accordance with para. ISTC-3300, ISTC-3310, or ISTC-3320.

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than ±25% change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than ±50% change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from subpara. (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5153 Stroke Test Corrective Action

(a) If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see subpara. ISTC-5151(b)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of para. ISTC-5152 shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see para. ISTC-9120).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see para. ISTC-9120).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5200 Other Valves

ISTC-5210 Manually Operated Valves. Valve testing shall be in accordance with para. ISTC-3500. If a valve fails to exhibit the required change of obturator position, the valve shall be immediately declared inoperable. Valves equipped with remote position indication shall be tested in accordance with para. ISTC-3700.

ISTC-5220 Check Valves

ISTC-5221 Valve Obturator Movement

(a) The necessary valve obturator movement during exercise testing shall be demonstrated by performing both an open and a close test.

(1) Check valves that have a safety function in both the open and close directions shall be exercised by initiating flow and observing that the obturator has traveled to either the full open position or to the position required to perform its intended function(s) (see para. ISTA-1100), and verify that on cessation or reversal of flow, the obturator has traveled to the seat.

(2) Check valves that have a safety function in only the open direction shall be exercised by initiating flow and observing that the obturator has traveled either the full open position or to the position required to perform its intended function(s) (see para. ISTA-1100), and verify closure.

(3) Check valves that have a safety function in only the close direction shall be exercised by initiating flow and observing that the obturator has traveled at least the partially open position,[3] and verify that on cessation or reversal of flow, the obturator has traveled to the seat.

Observations shall be made by observing a direct indicator (e.g., a position-indicating device) or by other positive means (e.g., changes in system pressure, flow rate, level, temperature, seat leakage, testing, or nonintrusive testing results).

(b) If a mechanical exerciser is used to exercise the valve, the force(s) or torque(s) required to move the obturator and fulfill its safety function(s) shall meet the acceptance criteria specified by the Owner.[4]

(1) Exercise test(s) shall detect a missing obturator, sticking (closed or open), binding (throughout obturator movement), and the loss or movement of any weight(s). Both an open and close test may not be required.

(2) Acceptance criteria shall consider the specific design, application, and historical performance.

(3) If impracticable to detect a missing obturator or the loss or movement of any weight(s) using a mechanical exerciser, other positive means may be used [e.g., seat leakage tests and visual observations to detect obturator loss and the loss or movement of external weight(s), respectively].

(c) If the test methods in subparas. (a) and (b) are impractical for certain check valves, or if sufficient flow cannot be achieved or verified, a sample disassembly examination program shall be used to verify valve obturator movement. If maintenance is performed on one of these valves that could affect its performance, the postmaintenance testing shall be conducted in accordance with subpara. (c)(4).

The sample disassembly examination program shall group check valves of similar design, application, and service condition and require a periodic examination of one valve from each group. The details and bases of the sampling program shall be documented and recorded in the test plan (see para. ISTC-9200).

(1) Grouping[5] of check valves for the sample disassembly examination program shall be technically justified and shall consider, as a minimum,[6] valve manufacturer, design, service, size, materials of construction, and orientation.

(2) During the disassembly process, the full-stroke motion of the obturator shall be verified. Full-stroke motion of the obturator shall be reverified immediately

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[3] The partially open position should correspond to the normal or expected system flow.

[4] If practicable, the force(s) or torque(s) required to move the obturator and fulfill any nonsafety function should be evaluated to detect abnormality or erratic action for corrective action.

[5] Maintenance and modification history should be considered in the grouping process.

[6] Valve grouping should also consider potential flow instabilities, required degree of disassembly, and the need for tolerance or critical dimension checks.

prior to completing reassembly. Check valves[7] that have their obturator disturbed before full-stroke motion is verified shall be examined to determine if a condition exists that could prevent full opening or reclosure of the obturator.

(3) At least one valve from each group shall be disassembled and examined at each refueling outage; all valves in each group shall be disassembled and examined at least once every 8 yr.

(4) Before return to service, valves that were disassembled for examination or that received maintenance that could affect their performance, shall be exercised full- or part-stroke, if practicable, with flow in accordance with para. ISTC-3520.[7] Those valves shall also be tested for other requirements (e.g., closure verification or leak rate testing) before returning them to service.

ISTC-5222 Condition-Monitoring Program. As an alternative to the testing or examination requirements of paras. ISTC-3510, ISTC-3520, ISTC-3530, ISTC-3550, and ISTC-5221, the Owner may establish a condition-monitoring program. The purpose of this program is both to improve valve performance[8] and to optimize testing, examination, and preventive maintenance activities[9] in order to maintain the continued acceptable performance of a select group of check valves. The Owner may implement this program on a valve or a group of similar valves. The program shall be implemented in accordance with this Division's Mandatory Appendix II, Check Valve Condition-Monitoring Program. If the condition-monitoring program for a valve or valve group is discontinued, then the requirements of Subsection ISTC shall apply.

ISTC-5223 Series Valves in Pairs.[10] If two check valves are in a series configuration without provisions to verify individual reverse flow closure (e.g., keepfill pressurization valves) and the plant safety analysis assumes closure of either valve (but not both), the valve pair may be operationally tested closed as a unit.

If the plant safety analysis assumes that a specific valve or both valves of the pair close to perform the safety function(s), the required valve(s) shall be tested to demonstrate individual valve closure.

ISTC-5224 Corrective Action. If a check valve fails to exhibit the required change of obturator position, it shall be declared inoperable. A retest showing acceptable performance shall be run following any required corrective action before the valve is returned to service.

Check valves in a sample disassembly program that are not capable of full-stroke movement (i.e., due to binding) or have failed or have unacceptably degraded valve internals, shall have the cause of failure analyzed and the condition corrected. Other check valves in the sample group that may also be affected by this failure mechanism shall be examined or tested during the same refueling outage to determine the condition of internal components and their ability to function.[11]

Series valve pairs tested as a unit in accordance with para. ISTC-5223 that fail to prevent reverse flow shall be declared inoperable, and both valves shall be either repaired or replaced.

ISTC-5230 Vacuum Breaker Valves. Vacuum breakers shall meet the applicable inservice test requirements of para. ISTC-5220 and Mandatory Appendix I of this Division.

ISTC-5240 Safety and Relief Valves. Safety and relief valves shall meet the inservice test requirements of Mandatory Appendix I of this Division.

ISTC-5250 Rupture Disks. Rupture disks shall meet the requirements for nonreclosing pressure relief devices of Mandatory Appendix I of this Division.

ISTC-5260 Explosively Actuated Valves

(a) A record of the service life of each charge in each valve shall be maintained. This record shall include the date of manufacture, batch number, installation date, and the date when service life expires based on manufacturer's recommendations. In no case shall the service life exceed 10 yr.

(b) Concurrent with the first test and at least once every 2 yr, the service life records of each valve shall be reviewed to verify that the service lives of the charges have not been exceeded and will not be exceeded before the next refueling. The Owner shall take appropriate actions to ensure charge service lives are not exceeded.

(c) At least 20% of the charges in explosively actuated valves shall be fired and replaced at least once every

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[7] Examples are spring-loaded lift check valves, or check valves with the obturator supported from the bonnet.

[8] Examples of candidates for improved valve performance are check valves that

(a) have an unusually high failure rate during inservice testing or operations

(b) cannot be exercised under normal operating conditions or during shutdown

(c) exhibit unusual, abnormal, or unexpected behavior during exercising or operation, or

(d) the Owner elects to monitor for improved valve performance.

[9] Examples of candidates for optimization of testing, examination, and preventive maintenance activities are check valves with documented acceptable performance that

(a) have had their performance improved under the Condition Monitoring Program

(b) cannot be exercised or are not readily exercised during normal operating conditions or during shutdown

(c) can only be disassembled and examined, or

(d) the Owner elects to optimize all of the associated activities of the valve group in a consolidated program.

[10] ISTC-5223 is only applicable to pre-2000 plants whose construction permit was issued January 1, 2000, or earlier.

[11] An evaluation should be made to determine if there are valves outside of the sampling group that could be affected by the failure mechanism. Valves that are determined to be directly affected by the failure mechanism should be examined or tested.

2 yr. If a charge fails to fire, all charges with the same batch number shall be removed, discarded, and replaced with charges from a different batch.

(d) Replacement charges shall be from batches from which a sample charge shall have been tested satisfactorily and with a service life such that the requirements of subpara. (b) are met.

(e) In addition to the requirements specified in Table ISTC-3500-1 (including requirements in ISTC-5260), post-2000 plants shall satisfy the following requirements for explosively actuated valves after commencement of commercial operation:

(1) At least once every 2 yr, each valve shall undergo visual examination of external surfaces and internal surfaces and parts.

(-a) Visual examination shall include documentation of the presence of fluids or other contaminants.

(-b) Any identified fluids or other contaminants within the internal mechanism that could potentially interfere with the function of the valve shall be removed, and their presence shall be evaluated to determine the impact on the operational readiness of the valve and its actuator.

(-c) This examination shall include verification of the initial operating position of the internal actuating mechanism.

(-d) Proper operation of remote position indicators shall be confirmed.

(2) At least once every 2 yr, one valve of each size shall be disassembled for internal examination of the valve and actuator.

(-a) This examination will verify the operational readiness of the valve assembly by evaluating the internal components for their operational functionality, ensuring the integrity of individual components, and removing any foreign material, fluid, or corrosion in accordance with the Owner's examination procedures.

(-b) All valves shall be disassembled for internal examination at least once every 10 yr.

(3) For the valves selected in the test sample for subpara. (c), the operational readiness of the actuation logic and associated electrical circuits must be verified for each sampled valve following removal of its charge. This verification must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available for each actuation circuit.

(4) For the valves selected in the test sample for subpara. (c), the sampling must select at least one explosively actuated valve from each redundant safety train every 2 yr. Each sampled pyrotechnic charge shall be tested in the valve or a qualified test fixture to confirm the capability of the charge to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping.

(5) Corrective action shall be taken in accordance with the Owner's corrective action requirements to resolve any deficiencies identified.

(-a) during examinations with postmaintenance testing conducted in accordance with subpara. ISTC-3100(d)

(-b) in the capability of a pyrotechnic charge in accordance with subpara. ISTC-3100(d) or

(-c) in the actuation logic or associated electrical circuits

(6) If deficiencies are identified that would prevent specified operation, the valve shall be declared inoperable in accordance with the Owner's requirements. Deficiencies shall be addressed for other explosively actuated valves, such as by internal examination or pyrotechnic charge and circuitry testing, as applicable, with appropriate actions based on those findings. Postmaintenance testing shall be conducted in accordance with subpara. ISTC-3100(d).

ISTC-6000 MONITORING, ANALYSIS, AND EVALUATION

To be provided at a later date.

ISTC-7000 TO BE PROVIDED AT A LATER DATE

ISTC-8000 TO BE PROVIDED AT A LATER DATE

ISTC-9000 RECORDS AND REPORTS

ISTC-9100 Records

ISTC-9110 Valve Records. The Owner shall maintain a record that shall include the following for each valve covered by this Subsection:

(a) the manufacturer and manufacturer's model and serial or other unique identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) preservice test results

(d) limiting value of full-stroke time specified in subparas. ISTC-5113(b), ISTC-5131(b), ISTC-5141(b), and ISTC-5151(b)

ISTC-9120 Record of Tests. See para. ISTA-9230.

ISTC-9130 Record of Corrective Action. See para. ISTA-9240.

ISTC-9200 Test Plans

In addition to the requirements of para. ISTA-3110, the Owner shall maintain a record of test plans that shall include the following:

(a) category of each valve

(b) justification for deferral of stroke testing in accordance with para. ISTC-3520

(c) details and bases of the check valve sample disassembly examination program, such as grouping characteristics, frequency, and justification for not performing an exercise test to at least a partially open position after reassembly or periodic exercising in accordance with para. ISTC-3520

(d) bases for testing series check valve pairs as a unit in accordance with para. ISTC-5223

Subsection ISTD Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants

ISTD-1000 INTRODUCTION

ISTD-1100 Applicability

The requirements of this Subsection apply to certain dynamic restraints (snubbers, pin to pin, inclusive).

ISTD-1110 Exclusions. Examination of support structures and attachments is outside the scope of this Code.[1]

ISTD-1400 Owner's Responsibility

In addition to the requirements of para. ISTA-1500, it is the Owner's responsibility to

(a) make available design and operating information necessary for the performance of the examination and testing program. Nonmandatory Appendix C contains a list of typical information that may be useful.

(b) identify and maintain a list of each snubber to be examined and tested in accordance with the rules of this Subsection.

(c) specify acceptance criteria for examination and testing.

ISTD-1500 Snubber Maintenance or Repair

Snubber repair activities shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, as applicable.

ISTD-1510 Maintenance or Repair Before Examination or Testing. Snubbers shall not be adjusted, maintained, or repaired before an examination or test specifically to meet the examination or test requirements.

ISTD-1520 Post-Maintenance or Repair Examination and Testing. Snubbers that are maintained or repaired by removing or adjusting a snubber part that can affect the results of tests required by para. ISTD-5120 shall be tested in accordance with the applicable requirements of para. ISTD-5120 before returning to service. Additionally, the requirements of para. ISTD-4110 shall be met. The requirements selected shall ensure that the parameters that may have been affected are verified to be acceptable by suitable examination and tests.[2]

ISTD-1600 Snubber Modification and Replacement

Snubber replacement activities shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, as applicable.

ISTD-1610 Suitability. Replacement or modified snubber(s) shall have a proven suitability for the application and environment.

ISTD-1620 Examination and Testing. Replacement or modified snubbers shall be examined and tested in accordance with written procedures. The applicable requirements of paras. ISTD-4100, ISTD-4200, ISTD-5200, and ISTD-5500 shall be included in these procedures. The requirements selected shall ensure that the criteria of paras. ISTD-4110, ISTD-4230, and ISTD-5210 can be satisfied.

ISTD-1700 Deletions of Unacceptable Snubbers

Snubbers may be deleted from the plant based on analysis of the affected piping system. When an unacceptable snubber is deleted, the deleted snubber shall nevertheless be considered in its respective examination population, examination category, or failure mode group (FMG) for determining the corrective action.

ISTD-1750 Transient Dynamic Event. If an unanticipated transient dynamic event that may affect snubber operational readiness occurs and is identified outside the scope and performance of para. ISTD-4200 or ISTD-5200, then the affected snubbers and systems shall be reviewed and any appropriate corrective action taken. Any action so taken shall be considered independent of the requirements of paras. ISTD-4200 and ISTD-5200. (15)

[1] Examination requirements for support structures and attachments can be found in Section XI of the ASME Boiler and Pressure Vessel Code.

[2] Examples of parts and activities that can affect the test results of para. ISTD-5120 are as follows:

(a) mechanical or hydraulic snubber internal moving parts

(b) hydraulic snubber internal seals (i.e., where bypass can affect test results)

(c) activities that can permit air to be entrapped in the main cylinder or the control valve of a hydraulic snubber

(d) hydraulic control valve adjustment

ISTD-1800 Supported Component(s) or System Evaluation

An evaluation shall be performed of the system(s) or components of which an unacceptable snubber is a part, for possible damage to the supported system or component.

(15) ISTD-2000 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms as used in this Subsection.

activation: the change of condition from passive to active, in which the snubber resists rapid displacement of the attached pipe or component.

application-induced failures: failures resulting from environmental conditions or application of the snubber for which it has not been designed or qualified.

defined test plan group (DTPG): a population of snubbers from which samples are selected for testing.

design or manufacturing failure: failures resulting from a potential defect in manufacturing or design that give cause to suspect other similar snubbers. This includes failures of any snubber that fails to withstand the environment or application for which it was designed.

diagnostic testing: testing to determine the cause or mechanism associated with failure, degradation, or performance anomaly of a snubber.

drag force: the force that will sustain low-velocity snubber movement without activation throughout the working range of the snubber stroke.

failure mode group (FMG): a group of snubbers that have failed and those other snubbers that have similar potential for similar failure.

fuel cycle: time period beginning with the start of the reactor until the completion of the next refuel outage and subsequent restart.

hydraulic snubbers: dynamic restraint devices in which load is transmitted through a hydraulic fluid.

inaccessible snubbers: snubbers that are in a high radiation area or other conditions that would render it impractical for the snubbers to be examined/tested under normal plant operating conditions without exposing plant personnel to undue hazards.

maintenance, repair, and installation-induced failures: failures that result from damage during maintenance, repair, or installation activities, the nature of which causes other snubbers to be suspect.

mechanical snubbers: dynamic restraint devices in which load is transmitted entirely through mechanical components.

normal operating conditions: operating conditions during reactor startup, operating at power, hot standby, reactor cooldown, and cold shutdown.

operating temperature: the temperature of the environment surrounding a snubber at its installed plant location during the phase of plant operation for which the snubber is required.

operational readiness testing: measurement of the parameters that verify snubber operational readiness.

release rate: the rate of the axial snubber movement under a specified load after activation of the snubber takes place.

replacement snubber: any snubber other than the snubber immediately previously installed at a given location.

service life: the period of time an item is expected to meet the operational readiness requirements without maintenance.

service life population: those snubbers for which the same service life has been established.

successful test campaign: campaign completed without having to test the entire defined test plan group (DTPG) population.

swing clearance: the movement envelope within which the snubber must operate without restriction, from the cold installed position to the hot operating position.

test campaign: the series of actions required to complete the testing of DTPG samples per ISTD-5200, ISTD-5300, and ISTD-5400, as applicable.

test interval: the period between completed test campaigns for a given DTPG.

test temperature: the temperature of the environment surrounding the snubber at the time of the test.

transient dynamic event failure: inability of a snubber to perform its intended function due to an unanticipated transient dynamic event.

unacceptable snubbers: snubbers that do not meet examination or testing requirements.

unanticipated transient dynamic event: any unforeseen or unanalyzed event, such as (but not limited to) a steam hammer, water hammer, void collapse, or seismic event greater than design basis.

unexplained failure: failure for which the cause has not been determined.

ISTD-3000 GENERAL REQUIREMENTS

ISTD-3100 General Examination Requirements

The following requirements apply to both the preservice and inservice examination programs.

ISTD-3110 Examination Boundary. The examination boundaries shall include the snubber assembly from pin to pin, inclusive.

ISTD-3120 Visual Examination. Snubbers shall be visually examined as specified in para. ISTD-4000.

ISTD-3200 General Testing Requirements

The following requirements apply to both the preservice and inservice testing programs.

ISTD-3210 Operational Readiness Testing Loads. Snubbers shall be tested at a load sufficient to verify the test parameters specified in paras. ISTD-5100 and ISTD-5200, ISTD-5300, or ISTD-5400 and ISTD-5500. Testing at less than rated load must be correlated to test parameters at rated load.

ISTD-3220 Test Correction Factors. This Subsection recognizes that there may be differences between the installed operating conditions and the conditions under which a snubber is tested. In such cases, correction factors shall be established and test results shall be correlated to operating conditions, as appropriate.

ISTD-3230 Snubber Test Parameters and Methods. Guidelines for establishing snubber functional test methods are given in this Division's Nonmandatory Appendix H, Test Parameters and Methods.

(15) **ISTD-3240 Test Acceptance Criteria.** The Owner shall establish and document test acceptance criteria for each applicable preservice and inservice test parameter specified in ISTD-5120 and ISTD-5210. Snubbers not meeting the established criteria shall be considered unacceptable in accordance with paras. ISTD-5320 and ISTD-5420. Criteria shall be established prior to initiation of a test campaign and shall not be revised for the duration of that test campaign.

ISTD-3300 General Service-Life Monitoring Requirements

Service life of snubbers shall be established and monitored per para. ISTD-6000.

ISTD-4000 SPECIFIC EXAMINATION REQUIREMENTS

ISTD-4100 Preservice Examination

ISTD-4110 Preservice Examination Requirements. A preservice examination shall be performed on all snubbers during initial plant startup. For new and modified systems, preservice examination shall be performed after placing the systems in service. For operating plants implementing Subsection ISTD, these requirements shall not be applicable if preservice examinations have been performed. Typical items to be considered are listed in Nonmandatory Appendix B of this Division. The initial examination shall, as a minimum, verify the following:

(a) No visible signs of damage or impaired operational readiness exist as a result of storage, handling, or installation.

(b) The snubber load rating, location, orientation, position setting, and configuration (e.g., attachments and extensions) are in accordance with design drawings and specifications. Installation records (based on physical examinations) of verification that the snubbers were installed according to the design drawings and specifications shall be acceptable in meeting this requirement.

(c) Adequate swing clearance is provided to allow snubber movement.

(d) If applicable, fluid is at the recommended level, and fluid is not leaking from the snubber system.

(e) Structural connections, such as pins, bearings, studs, fasteners, lock nuts, tabs, wire, and cotter pins, are installed correctly.

ISTD-4120 Reexamination. If the period between the preservice examination and initial system preoperational test exceeds 6 months, reexamination shall be performed in accordance with subparas. ISTD-4110(a), ISTD-4110(d), and ISTD-4110(e). This reexamination may be accomplished in conjunction with para. ISTD-4130.

ISTD-4130 Preservice Thermal Movement Examination Requirements. Snubber thermal movement shall be verified as indicated in paras. ISTD-4131 through ISTD-4133.

ISTD-4131 Incremental Movement Verification. During system heatup and cooldown at temperature plateaus specified by the Owner, record the thermal movement. Verify that the snubber movement during the thermal movement examination is within the design-specified range. Any discrepancies or inconsistencies shall be evaluated to determine the movement acceptability before proceeding to the next specified plateau.

ISTD-4132 Swing Clearance. Verify that swing clearance exists at specified heatup and cooldown plateaus.

ISTD-4133 Total Movement Verification. The total thermal movement from cold to hot at full operating temperature shall be recorded. This value may be measured directly if maximum operating temperature was attained, or it may be extrapolated from lower temperature readings. The cold or hot position setting shall be evaluated and adjusted if necessary, to ensure adequate snubber clearance from fully extended or retracted positions.

ISTD-4140 Preservice Examination Corrective Action. Snubbers that are installed incorrectly or otherwise fail to meet the requirements of para. ISTD-4110 shall be installed correctly, adjusted, repaired, or replaced. The installation-corrected, adjusted, repaired, or replacement snubber shall be examined in accordance with, and shall meet the requirements of para. ISTD-4110. Also, replacement snubbers shall meet the requirements of para. ISTD-5120.

ISTD-4200 Inservice Examination

Snubbers shall be visually examined on the required schedule and evaluated to determine their operational readiness.

ISTD-4210 Method and Objective. Inservice examination shall be a visual examination to identify physical damage, leakage, corrosion, or degradation that may have been caused by environmental exposure or operating conditions. External characteristics that may indicate operational readiness of the snubber shall be examined. An examination checklist shall be used. Typical items are listed in Nonmandatory Appendix B of this Division.

ISTD-4220 Snubber Categorization

(a) All of the snubbers shall be categorized as one population for examination or they may be categorized as accessible and inaccessible populations.

(b) The decision to categorize the snubbers as one population or as separate populations may be made during or after the examination.

(c) If combining accessible and inaccessible populations into one population, the shorter interval shall be used for subsequent examination.

ISTD-4230 Visual Examination Requirements. Snubber installations shall meet all of the requirements of paras. ISTD-4231 through ISTD-4233.

ISTD-4231 Restrained Movement. Snubbers shall be installed so they are capable of restraining movement when activated. Examinations shall include observations for the following and the conditions shall be evaluated when found:

(a) loose fasteners, or members that are corroded or deformed

(b) disconnected components or other conditions that might interfere with the proper restraint of movement

Snubbers evaluated to be incapable of restraining movement shall be classified unacceptable.

ISTD-4232 Thermal Movement. Snubber installations shall not restrain thermal movement to an extent that unacceptable stresses could develop in the snubber, the pipe, or other equipment that the snubber is designed to protect or restrain. This requirement is satisfied if no indication of binding, misalignment, or deformation of the snubber is observed.

ISTD-4233 Design-Specific Characteristics. Snubbers shall be free of defects that may be generic to particular designs as may be detected by visual examination. For example, fluid supply or content for hydraulic snubbers shall be observed. An observation that the fluid level is equal to or greater than the minimum specified amount that is sufficient for actuation at its operating extension is considered to satisfy this requirement. If the fluid is less than the minimum amount, the installation shall be identified as unacceptable, unless a test establishes that the performance of the snubber is within specified limits. Tests shall be performed in accordance with para. ISTD-5210.

ISTD-4240 Operational Readiness Test Evaluation. A snubber that requires further evaluation or is classified as unacceptable during inservice examination may be tested in accordance with the requirements of para. ISTD-5210. Results that satisfy the operational readiness test criteria of para. ISTD-5210 shall be used to accept the snubber, provided the test demonstrates that the unacceptable condition did not affect operational readiness.

ISTD-4250 Inservice Examination Intervals

ISTD-4251 Initial Examination Interval. The initial examination interval of snubbers shall begin no sooner than 2 months after attaining 5% reactor power operation and shall be completed by the end of first refueling outage. The initial interval shall not extend longer than 24 months after attaining 5% reactor power operation.

ISTD-4252 Subsequent Examination Intervals

(a) Subsequent examination intervals shall begin at the end of the previous examination interval, and conclude at the end of the next refueling outage.

(b) Intervals prior to the completion of the second refueling outage shall not exceed one fuel cycle in duration.

(c) The duration of examination intervals following the completion of the second refueling outage shall be in accordance with Table ISTD-4252-1. Examples of the application of Table ISTD-4252-1 are provided in Nonmandatory Appendix G.

(d) When examinations have been performed after the first refueling outage in accordance with a schedule requirement other than those in Table ISTD-4252-1, the interval preceding the most recently completed examination shall be used as the previous interval for the first application of Table ISTD-4252-1.

(e) Snubbers determined to be unacceptable based on the visual examination acceptance criteria at any time during the interval shall be counted in determining the subsequent examination interval in accordance with Table ISTD-4252-1.

ISTD-4260 Inservice Examination Sample Size. Inservice examination of snubbers required by paras. ISTD-4251 and ISTD-4252 shall include all snubbers based either on the whole population or on the accessibility categories, as established according to the provisions of para. ISTD-4220.

ISTD-4270 Inservice Examination Failure Evaluation. Snubbers that do not meet examination requirements of para. ISTD-4230 shall be evaluated to determine the cause of the unacceptability.

Table ISTD-4252-1 Visual Examination Table

Population or Category [Note (1)]	Number of Unacceptable Snubbers Column A for Extended Interval [Notes (2), (3)]	Column B for Interval Same as Previous [Notes (2), (4), (5)]	Column C for Interval Reduction to $^2/_3$ [Notes (2), (5), (6)]
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
≥1000	29	56	109

NOTES:
(1) Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. The next lower integer shall be used when interpolation results in a fraction.
(2) The basic interval shall be the normal fuel cycle up to 24 months. The examination interval may be as great as twice, the same, or as small as fractions of the previous interval as required by the following notes. The examination interval may vary ±25% only to accommodate an extended outage or an unplanned event during the examination interval. The ±25% variance is specifically not to be used to extend an examination for an additional refueling cycle.
(3) If the number of unacceptable snubbers is equal to or less than the number in Column A, then the next examination interval may be increased to twice the previous examination interval, not to exceed 48 months [±25% of the current interval as defined in Note (2) above]. In that case, the next examination according to the previous interval may be skipped.
(4) If the number of unacceptable snubbers exceeds the number in Column A, but is equal to or less than the number in Column B, then the next visual examination shall be conducted at the same interval as the previous interval.
(5) If the number of unacceptable snubbers exceeds the number in Column B, but is equal to or less than the number in Column C, then the next examination interval shall be decreased to two-thirds of the previous examination interval or, in accordance with the interpolation between Columns B and C, in proportion to the exact number of unacceptable snubbers.
(6) If the number of unacceptable snubbers exceeds the number in Column C, then the next examination interval shall be decreased to two-thirds of the previous interval.

ISTD-4280 Inservice Examination Corrective Action. Unacceptable snubbers shall be adjusted, repaired, modified, or replaced. Additional action regarding the examination interval shall be taken as indicated in Table ISTD-4252-1.

ISTD-5000 SPECIFIC TESTING REQUIREMENTS

ISTD-5100 Preservice Operational Readiness Testing

ISTD-5110 General. Preservice operational readiness testing shall be performed on all snubbers. Testing may be performed at the manufacturer's facility.

ISTD-5120 Test Parameters. Tests shall verify the following:

(a) activation is within the specified range of velocity or acceleration in tension and in compression.

(b) release rate, when applicable, is within the specified range in tension and in compression. For units specifically required not to displace under continuous load, ability of the snubber to withstand load without displacement.

(c) for mechanical snubbers, drag force is within specified limits in tension and in compression.

(d) for hydraulic snubbers, if required to verify proper assembly, drag force is within specified limits in tension and in compression.

ISTD-5130 Preservice Operational Readiness Testing Failures Corrective Action

ISTD-5131 Test Failure Evaluations. Snubbers that fail the preservice operational readiness test shall be evaluated for the cause(s) of failure(s).

ISTD-5132 Design Deficiency. If a design deficiency in a snubber is found, it shall be corrected by changing the design or specification, or by other appropriate means.

ISTD-5133 Other Deficiencies. Other deficiencies shall be resolved by adjustment, modification, repair, replacement, or other appropriate means.

ISTD-5134 Retest Requirements. Adjusted, modified, repaired, or replacement snubbers shall be tested to meet the requirements of para. ISTD-5120.

(15) ISTD-5200 Inservice Operational Readiness Testing

Snubbers shall be tested for operational readiness during each fuel cycle as defined in para. ISTD-5240. Test campaigns are required to be in accordance with a specified sampling plan as defined in para. ISTD-5260. Testing may be performed during normal system operation, or during system or plant outages. The Owner's administrative procedures shall govern removing snubbers from operable system(s).

ISTD-5210 Test Parameters. Snubber operational readiness tests shall verify the following:

(a) activation is within the specified range of velocity or acceleration in tension and in compression.

(b) release rate, when applicable, is within the specified range in tension and in compression. For units specifically required not to displace under continuous load, ability of the snubber to withstand load without displacement.

(c) for mechanical snubbers, drag force is within specified limits, in tension and in compression.

ISTD-5220 Test Methods

ISTD-5221 Test as Found. Snubbers shall be tested in their as-found condition regarding the parameters to be tested to the fullest extent practicable.

ISTD-5222 Restriction. Test methods shall not alter the condition of a snubber to the extent that the results do not represent the as-found snubber condition.

ISTD-5223 In-Place Test. Snubbers may be tested in their installed location by using Owner-approved test methods and equipment.

ISTD-5224 Bench Test. Snubbers may be removed and bench tested in accordance with Owner-approved procedures. After reinstallation, the snubbers shall meet the requirements of subparas. ISTD-4110(a) and ISTD-4110(c) through ISTD-4110(e). Also, the position setting shall be verified.

ISTD-5225 Subcomponent Test. When snubber size, test equipment limitations, or inaccessibility prevents use of methods in paras. ISTD-5223 and ISTD-5224, snubber subcomponents that control the parameters to be verified shall be examined and tested in accordance with Owner-approved test methods. Reassembly shall be in accordance with approved procedures that include the requirements of subparas. ISTD-4110(a), ISTD-4110(d), and ISTD-4110(e). Service life monitoring requirements are specified in para. ISTD-6400.

ISTD-5226 Correlation of Indirect Measurements. When test methods are used that either measure parameters indirectly, or measure parameters other than those specified, the results shall be correlated with specified parameters through established methods.

ISTD-5227 Parallel and Multiple Installations. Each snubber in a parallel or multiple installation shall be identified and counted individually.

ISTD-5228 Fractional Sample Sizes. Fractional sample sizes shall be rounded up to the next integer.

ISTD-5240 Test Frequency. An inservice test campaign shall be conducted every fuel cycle. Testing associated with each test campaign shall begin no earlier than 60 days before a scheduled refueling outage and shall be completed prior to completion of that refueling outage. (15)

ISTD-5250 Defined Test Plan Group (DTPG)

ISTD-5251 DTPGs General Requirement. The DTPGs shall include all snubbers except replacement snubbers and snubbers repaired or adjusted as a result of not meeting the examination acceptance requirements of para. ISTD-4200. These snubbers shall be exempt for the concurrent test interval.

ISTD-5252 DTPG Alternatives. Except as required by para. ISTD-5253, the total snubber population may be considered one DTPG, or alternatively, differences in design, application, size, or type may be considered in establishing DTPGs. DTPGs shall not be changed after initiating a test campaign. (15)

ISTD-5253 Additional DTPG Requirements for Pressurized Water Reactors. Snubbers attached to the steam generator and snubbers attached to the reactor coolant pump shall be at least one, separate DTPG.

ISTD-5260 Testing Sample Plans

ISTD-5261 Sample Plans. The snubbers of each DTPG shall be tested using either of the following:

(a) the 10% testing sample plan

(b) the 37 testing sample plan

Nonmandatory Appendix D of this Division includes a comparison of sample plans. Snubber testing plans are presented in flowchart form in Nonmandatory Appendix E of this Division.

ISTD-5262 Plan Selection. A test plan shall be selected for each DTPG before the scheduled test campaign begins. (15)

ISTD-5263 Plan Application. The test plan selected for a DTPG shall be used throughout the test campaign (15) for that DTPG and any failure mode group (FMG) that is derived from it.

ISTD-5270 Continued Testing. For unacceptable snubber(s), the additional testing shall continue in the DTPG or FMG per para. ISTD-5330 or ISTD-5430.

(15) **ISTD-5271 Test Failure Evaluation.** Snubbers that do not meet test requirements specified in para. ISTD-5210 shall be evaluated to determine the cause of the failure.

(a) The evaluation shall include review of information related to other unacceptable snubbers found during that test campaign.

(b) The evaluation results should be used, if applicable, to determine FMGs to which snubbers may be assigned. Evaluation information may be used to assign previously unexplained unacceptable snubbers to an appropriate FMG.

ISTD-5272 FMGs. Snubbers found unacceptable according to operational readiness test requirements may be assigned to FMGs. FMGs shall include all unacceptable snubbers with the same failure mode and all other snubbers with similar potential for similar failure. The following FMGs should be considered:

(a) design or manufacturing
(b) application induced
(c) maintenance, repair, or installation
(d) transient dynamic event

ISTD-5273 FMG Boundaries

(a) When snubbers have been tested as a part of DTPG test requirements and found to be unacceptable, and evaluation establishes an FMG based on the failure of certain snubbers, the number of those unacceptable snubbers shall be used in determining testing in the FMG in accordance with paras. ISTD-5320 and ISTD-5330, or paras. ISTD-5420 and ISTD-5430. However, those snubbers shall be counted only in the value of N of subpara. ISTD-5331(a) or ISTD-5431(a) as completed tests in the DTPG.

(b) When snubbers have been found to be acceptable when tested as part of DTPG test requirements and subsequent evaluation establishes an FMG that would include those snubbers, those snubbers shall not be counted in the value of N_F in subpara. ISTD-5331(b) or ISTD-5431(b) when counting FMG tests.

(c) An FMG shall remain as defined until corrective action is complete.

ISTD-5274 Snubbers in More Than One FMG. When a snubber is assigned to more than one FMG, it shall be counted in each of those FMGs and shall be included in corrective action for each of those FMGs.

ISTD-5275 Additional FMG Review. After the requirements of paras. ISTD-5250, ISTD-5260, ISTD-5270, ISTD-5320, and ISTD-5420 are satisfied for a DTPG, any separate and additional FMG review or testing does not require additional tests in the DTPG.

ISTD-5280 Corrective Action. Unacceptable snubbers shall be adjusted, repaired, modified, or replaced. The provisions of paras. ISTD-1620 and ISTD-1700 also apply. Snubbers that do not meet the test requirements of para. ISTD-5210 shall be tested in accordance with para. ISTD-5320 or ISTD-5420, as applicable.

ISTD-5300 The 10% Testing Sample

ISTD-5310 The 10% Testing Sample Plan, Sample Size, and Composition

ISTD-5311 Initial Sample Size and Composition. The initial sample shall be 10% of the DTPG, composed according to either subpara. (a) or (b).

(a) As practicable, the sample shall include representation from the DTPG based on the significant features (i.e., the various designs, configurations, operating environments, sizes, and capacities) and based on the ratio of the number of snubbers of each significant feature, to the total number of snubbers in the DTPG. Selection of the representative snubbers shall be random.

(b) The sample shall be generally representative as specified in subpara. (a), but may also be selected from snubbers concurrently scheduled for seal replacement or other similar activity related to service life monitoring. The snubbers shall be tested on a generally rotational basis to coincide with the service life monitoring activity.

ISTD-5312 Additional Sample Size. When additional samples are required by para. ISTD-5320, they shall be at least one-half the size of the initial sample from that DTPG.

ISTD-5313 Additional DTPG Sample Composition. When an unacceptable snubber has not been assigned to an FMG, the additional sample required by para. ISTD-5320 shall be taken from the DTPG. As practicable, the additional sample shall include the following:

(a) snubbers of the same manufacturer's design
(b) snubbers immediately adjacent to those found unacceptable
(c) snubbers from the same piping system
(d) snubbers from other piping systems that have similar operating conditions such as temperature, humidity, vibration, and radiation
(e) snubbers that are previously untested

ISTD-5314 FMG Sample Composition. When samples from an FMG are required, they shall be selected randomly from untested snubbers in the FMG.

ISTD-5320 The 10% Testing Sample Plan Additional Testing

ISTD-5321 DTPG Testing. When an applicable FMG has not been established, the number of unacceptable snubbers shall determine the additional testing samples in accordance with paras. ISTD-5312 and ISTD-5330.

ISTD-5323 FMG Testing. The following actions shall apply for FMG testing:

(a) Transient Dynamic Event FMG. The operational readiness of all snubbers in this FMG shall be evaluated by stroking or testing. All snubbers in this FMG that are determined to be operationally ready by stroking remain eligible for selection and tests for other appropriate FMGs and the DTPG in accordance with paras. ISTD-5313 and ISTD-5314. However, snubbers that are determined to be operationally ready by testing shall not be eligible for such tests.

(b) Other FMGs. Tests in each FMG shall be based both on the number of unacceptable snubbers found in the DTPG and determined by the evaluation of para. ISTD-5271 to be appropriate for establishing the FMG, and on the number of unacceptable snubbers subsequently found in the FMG. Testing shall continue until the mathematical expression of subpara. ISTD-5331(b) is satisfied or all snubbers in the FMG have been tested. Failures in an FMG shall require additional tests within the FMG unless the failure evaluation indicates that an additional and separate FMG is appropriate for additional tests from the DTPG.

ISTD-5330 The 10% Testing Sample Plan Completion. The snubbers of each DTPG and FMG shall be tested as required. Testing is complete when the mathematical expressions of para. ISTD-5331 are satisfied, or all snubbers in the DTPG or FMG have been tested.

ISTD-5331 Testing Plan Mathematical Expression. Testing shall satisfy the mathematical expressions as follows:

(a) for each DTPG

$$N \geq 0.1n + C(0.1n/2)$$

where

C = total number of unacceptable snubbers found in the DTPG (excluding those counted for FMG tests)
N = total number of snubbers tested that were selected from the DTPG
n = number of snubbers in the DTPG

(b) for each FMG

$$N_F \geq C_F(0.1n/2)$$

where

C_F = total number of unacceptable snubbers in the FMG, plus those found in the DTPG and used to establish the FMG
N_F = all snubbers selected and tested from the FMG after the FMG was established from the DTPG
n = number of snubbers in the DTPG

ISTD-5400 The 37 Testing Sample Plan

ISTD-5410 The 37 Testing Sample Plan, Sample Size, and Composition

ISTD-5411 Initial Sample Size and Composition. An initial sample of 37 snubbers shall be selected randomly from each 37 plan DTPG.

ISTD-5412 Additional Sample Size. When additional samples are required by para. ISTD-5420, the samples shall be either 18 or 19 snubbers to satisfy the requirement of para. ISTD-5431.

ISTD-5413 Additional Sample Selection. Additional samples, if required, shall be selected randomly from the remaining population of the DTPG, or from untested snubbers of the FMG as applicable.

ISTD-5420 The 37 Testing Sample Plan Additional Testing

ISTD-5421 DTPG Testing. When an applicable FMG has not been established, the number of unacceptable snubbers shall determine additional samples in accordance with para. ISTD-5412. The additional samples shall be selected randomly from the remaining untested snubbers of the DTPG.

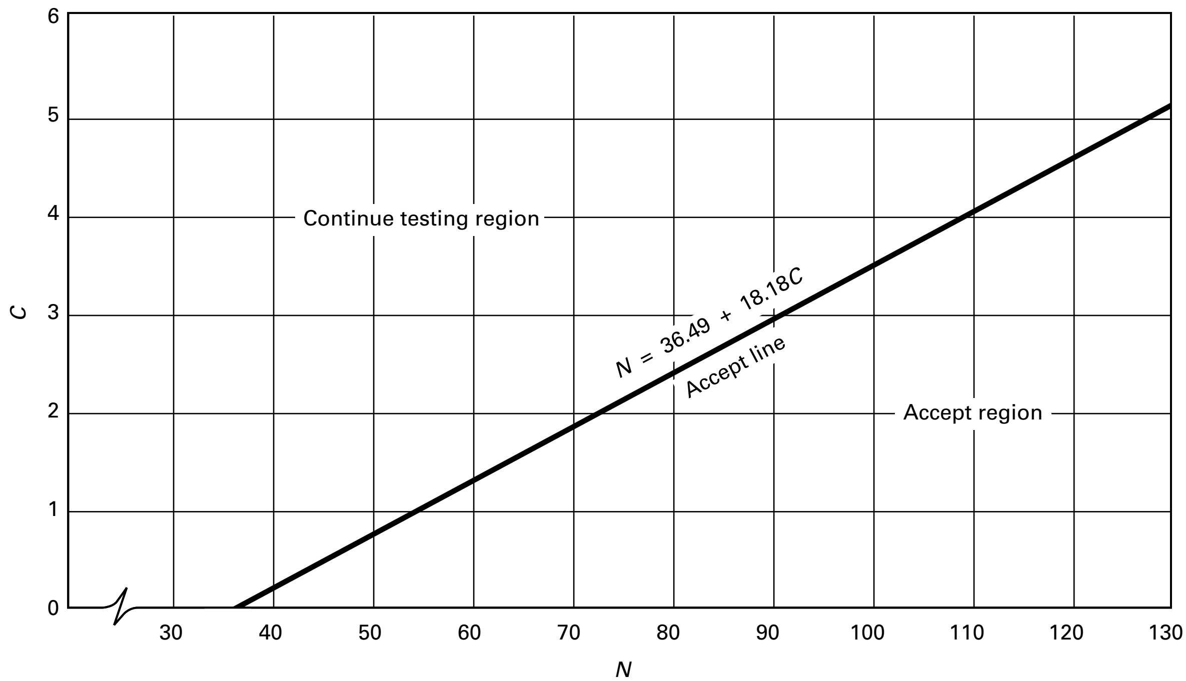
ISTD-5423 FMG Testing. The following actions shall apply for FMG testing:

(a) Transient Dynamic Event FMG. The operational readiness of all snubbers in this FMG shall be evaluated by stroking or testing. All snubbers in this FMG that are determined to be operationally ready by stroking remain eligible for selection and tests for other appropriate FMGs and the DTPG in accordance with para. ISTD-5413. However, snubbers that are determined to be operationally ready by testing shall not be eligible for such tests.

(b) Other FMGs. Tests in each FMG shall be based both on the number of unacceptable snubbers found in the DTPG and determined by the evaluation of para. ISTD-5271 to be appropriate for establishing the FMG, and on the number of unacceptable snubbers subsequently found in the FMG. Testing shall continue until the mathematical expression of subpara. ISTD-5431(b) is satisfied or all snubbers in the FMG have been tested. Failures in an FMG shall require additional tests within the FMG unless the failure evaluation indicates that an additional and separate FMG is appropriate for additional tests from the DTPG.

(c) Additional DTPG Testing Requirements. A supplemental sample shall be tested from the applicable DTPG for each FMG established to satisfy subpara. ISTD-5431(a). Failures in a supplemental sample require additional tests in the DTPG unless the failure evaluation indicates that an additional FMG is appropriate.

Fig. ISTD-5431-1 The 37 Testing Sample Plan



ISTD-5430 The 37 Testing Sample Plan Completion. The snubbers of each DTPG and FMG shall be tested as required. Testing is complete when the mathematical expressions of para. ISTD-5431 are satisfied, or all snubbers in the DTPG or FMG have been tested.

ISTD-5431 Testing Plan Mathematical Expressions. Testing shall satisfy the mathematical expressions as follows:

(a) for each DTPG

$$N \geq 36.49 + 18.18C \text{ (Fig. ISTD-5431-1)}$$

where

C = total number of unacceptable snubbers found in the DTPG (excluding those counted in FMG tests), plus one for each FMG established

N = total number of snubbers tested that were selected from the DTPG

(b) for each FMG requiring additional tests

$$N_F \geq 18.18C_F$$

where

C_F = total number of unacceptable snubbers in the FMG, plus those found in the DTPG and used to establish the FMG

N_F = all snubbers selected and tested after the FMG was established from DTPG

ISTD-5500 Retests of Previously Unacceptable Snubbers (15)

Snubbers placed in the same location as snubbers that failed during the previous test campaign shall be retested at the time of the subsequent test campaign unless the cause of the failure is clearly established and corrected so as to preclude reoccurrence. Any retest in accordance with this paragraph shall not be considered a part of the test campaign sample selection requirements of para. ISTD-5200, ISTD-5300, or ISTD-5400. In addition, failures found by these retests shall not require additional testing in accordance with para. ISTD-5320 or ISTD-5420, but shall be evaluated for appropriate corrective action.

ISTD-6000 SERVICE LIFE MONITORING

ISTD-6100 Predicted Service Life

Initial snubber service life shall be predicted based on manufacturer's recommendation or design review. Methods for predicting service life are given in Nonmandatory Appendix F of this Division.

ISTD-6200 Service Life Evaluation (15)

The service life for each location where a snubber is installed shall be reevaluated at least once each fuel cycle. Reevaluation shall be based on examination, maintenance, performance, and operating service-life history data associated with representative snubbers that have been in service in the plant, as well as other information related to service life. Completion of this reevaluation shall be documented in accordance with ISTD-9300(b). Examples of methods that can be used to obtain such data are described in Nonmandatory Appendix F of this Division. Based on the results of the reevaluation, each snubber's service life shall be increased, decreased, or left unchanged.

If any snubber's reevaluated service life will be exceeded before the next scheduled system or plant outage, one of the following actions shall be taken prior to the start of the cycle:

(a) the snubber shall be replaced with a snubber for which the service life will not be exceeded before the next scheduled system or plant outage

(b) technical justification shall be documented for extending the service life to or beyond the next scheduled system or plant outage

(c) the snubber shall be reconditioned such that its service life is extended to or beyond the next scheduled system or plant outage

ISTD-6300 Cause Determination

Causes for any snubber failures (regardless of the means or time of discovery) shall be determined, documented, and considered in establishing or reestablishing service life.

ISTD-6400 Additional Monitoring Requirements for Snubbers That Are Tested Without Applying a Load to the Snubber Piston Rod

The service life evaluation, for hydraulic snubbers that are tested without applying a load to the snubber piston rod, shall consider the results of the following requirements:

(a) monitoring the particulate, viscosity, and moisture content of one or more samples of hydraulic fluid from the main cylinder of the snubber. This may be accomplished using snubbers of the same design in a similar or more severe environment.

(b) monitoring of piston seal, piston rod seal, and cylinder seal integrity. If seal integrity is monitored by pressurization, pressures less than the snubber's rated load pressure may be used. Minimum pressure allowed shall be specified by the Owner.

ISTD-6500 Testing for Service Life Monitoring Purposes

If testing is conducted specifically for service life monitoring purposes, the results of such testing do not require testing of additional snubbers in accordance with para. ISTD-5320 or ISTD-5420, but shall be evaluated for appropriate corrective action.

ISTD-7000 TO BE PROVIDED AT A LATER DATE

ISTD-8000 TO BE PROVIDED AT A LATER DATE

ISTD-9000 RECORDS AND REPORTS

ISTD-9100 Snubber Records

The Owner shall maintain records that shall include the following for each snubber covered by this Subsection:

(a) the name of the manufacturer, and the manufacturer's model and serial numbers or other unique identification number

(b) a copy or summary of the manufacturer's acceptance test report, preservice test report, or current inservice test report

ISTD-9200 Test Plans

In addition to the applicable requirements of para. ISTA-3110, the Owner shall maintain a record of examination plans (accessible or inaccessible snubbers) and test plans (entire population or DTPGs) for all the snubbers.

ISTD-9300 Record of Tests (15)

(a) In addition to the requirements of para. ISTA-9230, the results of examination and test data shall include the manufacturer's model number, serial number, type, and unique location identification or the Owner's identification of the snubber, as applicable.

(b) Records of predicted service life of all snubbers and service life reevaluations shall be maintained.

ISTD-9400 Record of Corrective Action

See para. ISTA-9240.

Subsection ISTE
Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants

ISTE-1000 INTRODUCTION

(15) ISTE-1100 Applicability

This Subsection establishes the component safety categorization methodology and process[1] for dividing the population of pumps and valves, as identified in the IST Program Plan, into high safety significant component (HSSC) and low safety significant component (LSSC) categories.

ISTE-1200 Alternative

This Subsection specifies alternative inservice test requirements for certain pumps and valves, as identified in the IST Program Plan.

ISTE-1300 General

All the requirements of Subsections ISTA, ISTB, and ISTC apply, except as identified in Subsection ISTE. Valves for which test requirements are not specified in para. ISTE-5000 shall be tested in accordance with Subsection ISTC.

ISTE-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection.

aggregate risk: the risk due to programmatic changes in the IST program (test method effectiveness and/or testing interval) as measured by CDF or LERF.

basic event: an event in a fault tree model that requires no further development, because appropriate limit of resolution has been reached.

common cause failure (CCF): a failure of two or more components during a short period of time as a result of a single shared cause.

core damage: uncovery and heatup of the reactor core to the point at which prolonged oxidation and severe fuel damage is anticipated and involving enough of the core to cause a significant release.

core damage frequency (CDF): expected number of core damage events per unit of time. (A Level 1 PRA identifies accident sequences that can lead to core damage, calculates the frequency of each sequence, and sums those frequencies to obtain CDF.)

decision criteria: the quantitative and qualitative factors that influence a decision. These include both quantitative screening criteria (for PRA model) and the evaluation of other qualitative (or deterministic) factors that influence the results of an application.

defense in depth: considerations in an RI-IST Program that are maintained by consideration of CCF modes, consideration of appropriate failure modes, consideration of multiple risk metrics including CDF and LERF, consideration of test strategies, and assessment of aggregate risk.

Expert Panel: the team of experts responsible for categorizing affected components as either HSSCs or LSSCs.

figures-of-merit: the quantitative value, obtained from a PRA analysis, used to evaluate the results of an application (e.g., CDF or LERF).

Fussell-Vesely (F-V) Importance Measure: for a specified basic event, Fussell-Vesely importance is the fractional contribution to the total of the selected figure of merit for all accident sequences containing that basic event.

high safety significant components (HSSCs): components that have been designated as more important to plant safety by a blended process of PRA risk ranking and Plant Expert Panel evaluation.

importance measure: a mathematical expression that defines a quantity of interest. The most common importance measures are F-V and RAW.

initiating event: any event either internal or external to the plant that perturbs the steady state operation of the plant, if operating, thereby initiating an abnormal event such as transient or LOCA within the plant. Initiating events trigger sequences of events that challenge plant control and safety systems whose failure could potentially lead to core damage or large early release.

large early release: the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such there is a potential for early health effects.

[1] Component safety categorization methodology and process may result iin additional components being included in the IST program, since there may be components that are required for safe shutdown and accident mitigation that are not ASME Code Classes 1, 2, and 3.

large early release frequency (LERF): expected number of large early releases per unit of time. (A Level 2 PRA identifies accident sequences that can lead to radioactivity release, calculates the frequency of each sequence, and sums these frequencies to obtain LERF.)

living PRA: a plant-specific PRA that is maintained up to date, such that plant modifications, plant operation changes (including procedure changes), component performance, and other technical information significantly affecting the model are reflected in the model.

low safety significant components (LSSCs): components that have been designated as less important to plant safety by a blended process of PRA risk ranking and Plant Expert Panel evaluation.

PRA failure rate: the conditional probability of failure of a component on the next demand (for standby component) or in the next hour of operation (for operating component), given that it has not already failed.

probabilistic risk assessment (PRA): a qualitative and quantitative assessment of the risk associated with plant operation and maintenance that is measured in terms of frequency of occurrence of risk metrics, such as core damage or a radioactive material release and its effects on the health of the public [also referred to as a probabilistic safety assessment (PSA)]. In general the scope of a PRA is divided into three categories: Level 1, Level 2, and Level 3. A Level 1 maps from initiating events to plant damage states, including their aggregate, core damage. Level 2 includes Level 1 mapping from initiating events to release categories (source term). A Level 3 includes Level 2 and uses the source term of Level 2 to quantify sequences, the most common of which are health effects and property damage in terms of cost.

risk achievement worth (RAW): for a specified basic event, the increase in a selected figure of merit when an SSC is assumed to be unable to perform its function due to testing, maintenance, or failure. It is the ratio or interval of the figure of merit, evaluated with the SSC's basic event probability set to one, to the base case figure of merit.

risk significance: importance of plant components, based on their functions, using PRA methods only (i.e., without deterministic or other qualitative information as might be used by the Plant Expert Panel).

safety margin: considerations in an RI-IST Program shall be maintained by performance criteria for the components, Plant Expert Panel utilization, and monitoring/trending/analysis/evaluation.

safety significance: an item's contribution to plant risk using a blended process of PRA methods and Plant Expert Panel evaluation.

testing effectiveness: the ability of a test to determine key performance attributes of a component without damaging the component or adversely affecting plant safety. (Testing effectiveness can be determined by a type of test that is nondestructive, does not remove the component from service, identifies appropriate functional failure modes, detects precursors to malfunction; and predicts degradation leading to failure.)

truncation limits: the numerical cutoff value of probability or frequency below which results are not retained in quantitative PRA model or used in subsequent calculations (such limits can apply to accident sequences/cut sets, system level cut sets, and sequence/cut set database retention).

ISTE-3000 GENERAL REQUIREMENTS

ISTE-3100 Implementation (15)

The requirements of this Subsection shall be implemented for all IST components of the same type. Component types are defined as

(a) centrifugal pumps, including vertical line shaft pumps

(b) positive displacement pumps

(c) motor-operated valves (MOVs)

(d) pneumatically operated valves (AOVs)

(e) check valves (CVs)

Other types of components (e.g., manual valves, solenoid valves, hydraulically operated valves, pressure relief valves) shall be tested in accordance with the requirements of the applicable subsection.

ISTE-3200 Probabilistic Risk Assessment

ISTE-3210 Plant-Specific PRA. The Owner is responsible for demonstrating the technical adequacy of any PRA used as the basis to perform component risk ranking. PRA technical adequacy shall be assessed against ASME/ANS RA-S–2008[2] or a set of acceptance criteria that is endorsed by the regulatory agency having jurisdiction over the plant site. (15)

ISTE-3220 Living PRA. The PRA shall be maintained up to date.

ISTE-3300 Integrated Decision Making

ISTE-3310 Plant Expert Panel. A Plant Expert Panel shall be designated to perform the blended safety evaluation of probabilistic and deterministic engineering information for each component.

ISTE-3320 Integrated Effects. Components can be affected by more than one risk-informed application (e.g., risk-informed inservice testing, risk-informed inservice inspection, graded quality assurance). Integrated effects of multiple risk-informed applications

[2] ASME/ANS RA-S–2008, with the RA-Sa–2009 Addenda, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications.

(including risk-informed applications outside of the ASME scope) shall be evaluated.

ISTE-3330 Determination of HSSC and LSSC. The Plant Expert Panel shall evaluate each component and categorize it as HSSC or LSSC, using PRA quantitative information (if component is modeled) and engineering qualitative information (for both modeled and not modeled components).

ISTE-3400 Evaluation of Aggregate Risk

The aggregate risk impact of changes to the IST program shall be evaluated by the Owner (e.g., Plant Expert Panel). Decision criteria, quantitative evaluations, and qualitative assessments are a part of this aggregate risk impact evaluation.

ISTE-3500 Feedback and Corrective Actions

Feedback and corrective action processes are required elements of this Subsection as specified in para. ISTE-6200.

ISTE-4000 SPECIFIC COMPONENT CATEGORIZATION REQUIREMENTS

In addition to requirements of para. ISTE-3000, the following requirements apply to component categorization into HSSC and LSSC categories, and to an RI-IST program based on those categories.

ISTE-4100 Component Risk Categorization

This paragraph establishes requirements for separating components into HSSC or LSSC categories, performing PRA sensitivity studies to ensure that assumptions in the PRA are not masking the importance of a component, and determining how to treat components not modeled.

ISTE-4110 Appropriate Failure Modes. Component risk categorization shall be based on basic events that include failure modes representing functions addressed by inservice testing (e.g., pump failure to run, valve failure to open, common cause failure).

ISTE-4120 Importance Measures

(a) As a minimum, two importance measures, F-V and RAW, shall be calculated for those components modeled in the PRA.

(b) Importance measures should be evaluated for both CDF and LERF, if available.

ISTE-4130 Screening Criteria. For those components modeled in the PRA,

(a) a threshold value of F-V >0.005 or lower based on either CDF or LERF should be initially considered as HSSC

(b) a threshold value of RAW >2 based on either CDF or LERF should be initially considered as HSSC

ISTE-4140 Sensitivity Studies

(a) The following sensitivity studies shall be performed:

(1) Data and Uncertainties. Failure probabilities of components, within the PRA models for those IST components that have initially very high or very low values, shall be selectively increased and/or decreased to determine if the results are sensitive to changes in the failure data. If sensitivities are indicated, steps shall be taken to determine if uncertainty ranges can be reduced and to validate the failure probabilities included in the models.

(2) Human Recovery Actions. The PRA shall be requantified, and the F-V and RAW importance measures recalculated, after human actions modeled in the PRA, to recover from specific component failures, are adjusted in the models (e.g., the probability of successful recovery due to human intervention is adjusted by factor of 10).

(3) Test and Maintenance Unavailabilities. The PRA models shall be requantified with test and maintenance unavailabilities adjusted, and the importance measures recalculated.

(4) LSSC Failure Rates. Failure rates for components initially ranked LSSC shall be increased by a factor representing the upper bound (95%) of the failure rate and the PRA models requantified. The importance measures shall then be recalculated.

(5) Truncation Limits. If the PRA has not been quantified with a truncation limit 10^{-4} *below the baseline PRA CDF,* the PRA model shall be requantified with the truncation limit lowered to this value. The importance measures shall then be recalculated.

(6) Common Cause. Sensitivity analyses shall be used to determine the impact of increased or decreased common cause failure rates. Importance measures shall then be recalculated.

(b) The results of these sensitivity studies and any others that are performed shall be documented. In addition to the magnitude of the changes to the CDF or LERF, all insights obtained from the results shall be described.

The results and insights of these sensitivity studies shall be provided to the Plant Expert Panel for their consideration in the final categorization of the components.

ISTE-4150 Qualitative Assessments. Qualitative assessments shall be performed for all LSSCs, modeled and not modeled in the PRA, to determine whether there are other bases for categorizing IST components.

(a) The following qualitative assessments shall be performed:

(1) impact of initiating events (e.g., the impact of failure or degradation as it might result in an initiator, component contribution to initiating events represented by point estimates)

(2) potential consequences of shutdown (outage) conditions

(3) response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding, etc.)

(4) impact of LERF, if not used in subpara. ISTE-4120(b)

(b) Qualitative assessments shall be performed for plant-specific design bases conditions and events not modeled in a PRA.

(c) Qualitative assessments shall consider the impacts upon the plant to

(1) prevent or mitigate accident conditions

(2) reach and/or maintain safe shutdown conditions

(3) preserve the reactor primary coolant pressure boundary integrity

(4) maintain containment integrity

(d) Qualitative assessments shall also consider

(1) safety function being satisfied by the component's operation

(2) level of redundancy existing at the plant to fulfill the component's function

(3) ability to recover from a failure of the component

(4) performance history of the component

(5) plant technical specifications requirements applicable to the component

(6) emergency operating procedure instructions that use the component(s)

(7) design and current licensing basis information relevant to RI-IST component function

(e) The cumulative impacts of combinations of component unavailability, which could impact an entire system (e.g., multi-train impacts) or critical safety function (e.g., multi-system impacts), shall also be considered.

(f) These qualitative assessments and the Plant Expert Panel's disposition of them shall be documented.

(g) These qualitative assessments shall be available to the Plant Expert Panel for their decision of component safety categorization.

ISTE-4160 Components Not Modeled. If IST components not modeled in the PRA are subsequently determined by the Plant Expert Panel to have an impact upon the ability of the facility to respond to analyzed events, consideration should be given to updating the PRA model to incorporate the effects of the component(s), then using the updated model to provide a quantified basis for categorization (either HSSC or LSSC).

ISTE-4200 Component Safety Categorization

This paragraph provides requirements for the Plant Expert Panel's review and evaluation process for categorizing IST components relative to their safety significance, using both deterministic and probabilistic insights.

ISTE-4210 Plant Expert Panel Utilization. The Plant Expert Panel shall blend deterministic and probabilistic information to classify IST components into HSSC or LSSC categories.

(a) PRA Insights. The results of PRA analyses shall be used by the Plant Expert Panel to help determine the safety significance of components within the scope of RI-IST and PRA programs. Information contained in PRAs relative to the role of components in mitigating or preventing core damage events or radiological release events shall be considered. The scope of the PRA and depth of probabilistic analyses shall be assessed, evaluated, and documented. As a minimum, the following shall be documented:

(1) the level of plant specific PRA analysis available for assessing the applicability of PRA information relative to IST programs. For example, written documentation shall describe the level of plant specific PRA analysis such as Level 1 PRA (assessment of core damage frequency) and/or Level 2 PRA (assessment of core damage frequency plus containment performance).

(2) scope of initiating events considered (internal, external, both).

(3) typical failure modes considered (e.g., hardware failures, testing/maintenance failures, common cause failures, and human errors).

(4) PRA scope for plant configurations (e.g., low power risk, shutdown risk, transition mode risk, at-power risk) reviewed relative to the applicability of PRA information and IST component function(s).

(b) Deterministic Insights. The Plant Expert Panel shall also consider deterministic factors when assessing the safety significance of components within the scope of IST programs (see Nonmandatory Appendix K of this Division for a sample list of deterministic considerations).

ISTE-4220 Plant Expert Panel Requirements (15)

(a) Plant Procedure. An approved plant procedure shall describe the process, including

(1) designated members and alternates

(2) designated chairperson and alternate

(3) quorum

(4) attendance records

(5) agendas

(6) motions for approval

(7) process for decision making

(8) documentation and resolution of differing opinions

(9) minutes

(10) implementation of feedback/corrective actions

(11) feedback to the PRA

(12) required training

(b) *Training.* The Plant Expert Panel shall be trained and indoctrinated by the Owner in the specific requirements to be used for this Subsection. Training and indoctrination shall include the application of risk analysis methods and techniques used for this Subsection. At a minimum, the risk methods and techniques should include

(1) PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty)

(2) use of risk importance measures

(3) assessment of failure modes

(4) reliability versus availability

(5) risk thresholds

(6) expert judgment elicitation

Each of the aforementioned topics shall be covered in the indoctrination to the extent necessary to provide the Plant Expert Panel with a level of knowledge needed to adequately evaluate and approve the scope of the IST selections, using both probabilistic and deterministic information.

(c) *Expertise.* Member expertise levels shall be documented and maintained.

(d) *Membership*

(1) There shall be at least five experts designated as members of the Plant Expert Panel. Members may be experts in more than one field; however, excessive reliance on any one member's judgment shall be avoided.

(2) The chairperson shall be familiar with this Subsection and shall facilitate Plant Expert Panel activities, to ensure that the requirements of this Subsection are satisfied.

(3) Expertise in the following functions shall be represented on the Plant Expert Panel:

(-a) operation

(-b) safety analysis engineering

(-c) probabilistic risk assessment

(-d) ASME inservice testing

(4) Additional members of the Plant Expert Panel who have the following plant expertise may be selected:

(-a) systems performance

(-b) maintenance

(-c) licensing

(-d) component performance

(-e) quality assurance

(-f) design engineering

(5) Alternate members to the Plant Expert Panel may be designated on a temporary basis; however, vacancies in the Plant Expert Panel membership should be filled within a reasonable period of time. Alternate members must meet the same requirements as permanent members.

(6) Other plant or nuclear industry experts may be invited to attend some or all of the sessions of the Plant Expert Panel as visitors to provide observations, opinions, or recommendations.

ISTE-4230 Plant Expert Panel Decision Criteria. Plant Expert Panel decision criteria for categorizing components as HSSC and LSSC shall be documented.

ISTE-4240 Reconciliation. Decisions of the Plant Expert Panel shall be arrived at by consensus. Differing opinions shall be documented and resolved, if possible. (15)

(a) If a resolution cannot be achieved concerning the safety significance classification of a component, then the component shall be classified HSSC.

(b) If components have a high initial ranking from the PRA (i.e., RAW >2 or F-V >0.005) but are ultimately ranked as LSSCs, the Plant Expert Panel decisions shall provide justification and shall be documented.

ISTE-4300 Testing Strategy Formulation

(a) Testing strategies for HSSCs and LSSCs shall be developed following the requirements specified in para. ISTE-5000.

(b) After testing strategies are developed, the planned changes (e.g., test frequency, testing effectiveness, and out-of-service duration) shall be provided for input to the evaluation of aggregate risk.

ISTE-4400 Evaluation of Aggregate Risk

ISTE-4410 Decision Criteria

(a) Appropriate decision criteria for aggregate risk effects shall be established and documented.

(1) Decision criteria shall be based on thresholds for aggregate risk limits using standard figures-of-merit (e.g., CDF, LERF). (Nonmandatory Appendix L of this Division provides guidance.)

(2) Performance criteria used for other regulatory requirements may be taken into consideration when developing decision criteria for aggregate risk effects.

(b) Decision criteria may be determined both qualitatively and quantitatively.

ISTE-4420 Quantitative Assessment

(a) An aggregate risk evaluation shall be performed prior to implementation, as applicable, using the PRA.

(1) Quantitative attributes associated with this Subsection shall be considered and included in the quantitative evaluation, as appropriate, and within the scope of the PRA.

(2) Each applicable quantitative IST attribute shall be incorporated into the quantitative evaluation, as appropriate, until all proposed changes have been dispositioned (i.e., incorporated or not incorporated).

(3) Once all appropriate inputs have been incorporated, the PRA shall be rerun to assess the overall risk impact.

(4) Proposed IST program changes shall be assessed to determine compliance with approved

decision criteria and to quantitatively determine if any adjustments or compensatory measures are warranted.

(b) Types of quantitative attributes that should be considered in the quantitative evaluation include changes in

(1) testing frequency
(2) out-of-service duration
(3) failure rates
(4) failure modes
(5) common cause failure susceptibility
(6) compensatory measures
(7) testing scheme (staggered or simultaneous testing)

Compensatory measures include both those specifically incorporated into plant programs and those developed for specific situations. Management-directed compensatory measures should also be included in the quantitative assessment, as appropriate. Documented failure rates shall be used in the quantification process for IST component.

(c) Testing effectiveness shall be evaluated by periodic assessments or when new failure modes are identified that impact risk quantification.

(1) New failure modes shall be incorporated in accordance with risk management and corrective action programs into the quantitative evaluation, as appropriate.

(2) Changes resulting from programs that significantly affect the reliability or availability of components that perform important safety functions shall be assessed, and, if appropriate, incorporated into the PRA for requantification.

Such assessments may be performed in conjunction with the plant specific Maintenance Rule (10 CFR 50.65) requirements.

ISTE-4430 Qualitative Evaluation

(a) Aggregate risk effects shall be qualitatively evaluated (i.e., risk decreases as well as risk increases) for IST program changes (e.g., testing effectiveness).

(b) Pertinent performance indicators, industry programs, or other scrutable methods for establishing aggregate risk effects shall be identified and monitored.

(c) Feedback processes and corrective action programs as described in para. ISTE-6200 shall be considered in the evaluation of aggregate risk.

ISTE-4440 Defense in Depth. The IST aspects of defense in depth shall be maintained.

ISTE-4450 Safety Margins. The IST aspects of safety margin shall be maintained.

ISTE-4500 Inservice Testing Program

ISTE-4510 Maximum Testing Interval. The maximum testing interval shall be based on the more limiting of the following:

(a) the results of the aggregate risk

(b) performance history of the component

ISTE-4520 Implementation Schedule. A schedule shall be developed for implementing the testing strategies as specified in para. ISTE-5000.

ISTE-4530 Assessment of Aggregate Risk. Once the test schedule has been developed, the schedule shall be assessed against the assumptions of the aggregate risk evaluation.

ISTE-4540 Transition Plan. A transition plan shall be developed for each component type to ensure adequate information is collected to support justification of stepwise test interval extension up to and including the maximum allowable interval. Staggered test intervals may be used for implementing a stepwise test interval extension.

ISTE-5000 SPECIFIC TESTING REQUIREMENTS

ISTE-5100 Pumps

ISTE-5110 High Safety Significant Pump Testing. Pumps categorized as HSSCs shall meet all requirements of Subsections ISTA and ISTB or ISTF.

ISTE-5120 Low Safety Significant Pump Testing

ISTE-5121 Low Safety Significant Pump Testing — Pre-2000 Plants[3]

(a) Group A and Group B pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTB, except that the testing requirements identified in this paragraph and in Table ISTE-5121-1 may be substituted for those in para. ISTB-3400 (Table ISTB-3400-1).

(b) All Group A and Group B LSSC pumps shall receive an initial Group A test conducted within ±20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.

Table ISTE-5121-1 LSSC Pump Testing

Pump Group	Group A Test [Note (1)]	Group B Test	Comprehensive Test
Group A (routinely or continuously operated pumps)	6 months [Note (2)]	Not required	Not required
Group B (standby pumps)	2 yr	6 months [Note (2)]	Not required

NOTES:
(1) This column also applies if using Subsection ISTF.
(2) To meet vendor recommendations, pump operation may be required more frequently than the specified test frequency.

[3] *Pre-2000 plant:* a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

(c) Thereafter, all Group A and Group B LSSC pumps shall be Group A tested within ±20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.

ISTE-5122 Low Safety Significant Pump Testing — Post-2000 Plants[4]

(a) Pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTF, except that the testing requirements identified in this paragraph and in Table ISTE-5121-1 may be substituted for those in para. ISTF-3400.

(b) All LSSC pumps shall receive an initial test conducted within ±20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.

(c) Thereafter, the LSSC pumps shall be tested every 6 months in accordance with Subsection ISTF and within ±20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.

ISTE-5130 Maximum Test Interval — Pre-2000 Plants. If the maximum test interval as determined from para. ISTE-4510 for a specific pump is more limiting than the interval of para. ISTE-5110 or para. ISTE-5120 (as applicable), the most limiting interval shall be used for that pump. A Group A or Group B test, as applicable, shall be performed to satisfy the increased test frequency requirements.

ISTE-5200 Check Valves

In lieu of meeting the inservice exercising test requirements for Category C check valves as specified in para. ISTC-3522, the following alternative may be applied.

ISTE-5210 High Safety Significant Check Valve Testing. HSSC check valves shall be placed in a Condition Monitoring Program and tested in accordance with Mandatory Appendix II of this Division. The Condition Monitoring Program shall include identification and trending of attributes indicative of degradation that could lead to the occurrence of the failure mode(s) that resulted in HSSC categorization.

ISTE-5220 Low Safety Significant Check Valve Testing. LSSC check valves shall be tested in accordance with para. ISTC-3522 or placed in a Condition Monitoring Program and tested in accordance with Mandatory Appendix II of this Division.

(15) ISTE-5300 Motor-Operated Valve Assemblies

In lieu of the rules for preservice and inservice testing to assess the operational readiness of certain electric motor-operated valve assemblies in light-water reactor power plants in OM Code Subsection ISTC, HSSC and LSSC MOVs shall meet the requirements of Mandatory Appendix III of this Division, except as provided in para. ISTE-5320 below. The Leak Testing Requirements of para. ISTC 4.3 (1995 Edition with the 1996 and 1997 Addenda) or para. ISTC-3600 (1998 Edition and later) continue to apply, as applicable.

ISTE-5310 High Safety Significant MOVs. HSSC MOVs shall be tested in accordance with Mandatory Appendix III of this Division, using established test frequencies and utilizing a mix of static and dynamic MOV performance testing.

ISTE-5320 Low Safety Significant MOVs. In lieu of meeting the inservice test frequency requirements of Mandatory Appendix III of this Division, the following alternative rules may be applied:

(a) LSSC MOVs grouping shall be technically justified, but need not comply with all the requirements of Mandatory Appendix III of this Division.

(b) LSSC MOVs shall be associated with an established group of other MOVs wherever possible. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with Mandatory Appendix III of this Division and applied to all LSSCs associated with that group.

(c) LSSC MOVs that are not able to be associated with an established group, shall be inservice tested in accordance with Mandatory Appendix III of this Division using an initial test frequency of three refueling cycles or 5 yr (whichever is longer) until sufficient data exists to determine a more appropriate test frequency.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with Mandatory Appendix III of this Division.

ISTE-5400 Pneumatically Operated Valves (15)

ISTE-5410 High Safety Significant Pneumatically Operated Valve Assemblies Testing

(a) HSSC AOVs shall meet all the requirements of Subsections ISTA and ISTC, except as provided in subpara. (b) below.

(b) HSSC AOVs shall be tested in accordance with Mandatory Appendix IV of this Division, which is in the course of preparation.

ISTE-5420 Low Safety Significant Pneumatically Operated Valve Assemblies Testing

(a) LSSC AOVs shall meet all the requirements of Subsections ISTA and ISTC, except as provided in subpara. (b) below.

(b) LSSC AOVs shall meet all the requirements of Mandatory Appendix IV of this Division, which is in the course of preparation.

[4] *Post-2000 plant:* a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

ISTE-5500 To Be Provided at a Later Date

ISTE-6000 MONITORING, ANALYSIS, AND EVALUATION

ISTE-6100 Performance Monitoring

ISTE-6110 HSSC Attribute Trending. For HSSCs, a set of attributes to be tested shall be established and compared to acceptance criteria in accordance with para. ISTE-5000, and a trending program shall be implemented for those attributes selected for monitoring.

ISTE-6120 LSSC Performance Trending. For LSSCs, the inservice testing specified in para. ISTE-5000 shall be supplemented by performance monitoring. The performance of the LSSCs shall be trended to ensure the component failure rates do not increase to unacceptable levels.

ISTE-6200 Feedback and Corrective Actions

ISTE-6210 Feedback

(a) A feedback process incorporating elements of both conditional and periodic feedback shall be established such that component performance information is directed to both the IST and PRA programs. Conditional feedback shall occur in a timely fashion following component failure. Periodic feedback shall be considered for maintenance of the PRA.

(b) Each program shall assimilate performance information to ensure the appropriate unavailability information is reflected in decision making.

(c) A feedback process shall be established so IST programmatic changes are directed to the PRA program.

(d) Feedback frequency should not exceed two refueling cycles.

ISTE-6220 Corrective Action. In addition to the requirements in the IST Code of Record with respect to Corrective Actions, a Corrective Action Program shall be established that identifies and tracks to resolution all failures of similar types of components within an RI-IST Program incorporating risk insights, including evaluation of generic implications.

ISTE-6230 Component Safety Significance Recategorization. The component's operational readiness is not changed by recategorization.

ISTE-7000 TO BE PROVIDED AT A LATER DATE

ISTE-8000 TO BE PROVIDED AT A LATER DATE

ISTE-9000 RECORDS AND REPORTS

In addition to the requirements in the Code of Record with respect to records, the Plant Expert Panel and component records listed in paras. ISTE-9100 and ISTE-9200, respectively, shall be maintained:

ISTE-9100 Plant Expert Panel Records

(a) membership and attendance

(b) member expertise representation and training per subpara. ISTE-4220(b)

(c) member experience (years of experience in each of the expertise categories)

(d) meeting agendas

(e) meeting minutes

(f) plant procedure

ISTE-9200 Component Records

(a) risk significance based on PRA importance measures

(b) additional PRA quantitative information

(c) deterministic information

(d) Plant Expert Panel categorization decisions of HSSC or LSSC

(e) basis for the HSSC/LSSC decision

Subsection ISTF
Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants — Post-2000 Plants[1]

ISTF-1000 INTRODUCTION

ISTF-1100 Applicability

The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.

ISTF-1200 Exclusions

The following are excluded from this Subsection:

(a) drivers, except where the pump and driver form an integral unit and the pump bearings are in the driver

(b) pumps that are supplied with emergency power solely for operating convenience

(c) skid-mounted pumps that are tested as part of the major component and are justified by the Owner to be adequately tested

ISTF-1300 Owner's Responsibility

In addition to the requirements of para. ISTA-1500, it is the Owner's responsibility to

(a) include in both the pumps and plant design all necessary valving, instrumentation, test loops, required fluid inventory, or other provisions that are required to fully comply with the requirements of this Subsection. Testing capability shall be possible irrespective of plant mode.

(b) identify each pump to be tested in accordance with the rules of this Subsection.

ISTF-2000 SUPPLEMENTAL DEFINITIONS

The following is provided to ensure a uniform understanding of selected terms used in this Subsection:

vertical line shaft pump: a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.

ISTF-3000 GENERAL TESTING REQUIREMENTS

The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action.

The parameters to be measured during preservice and inservice testing are specified in Table ISTF-3000-1.

ISTF-3100 Preservice Testing

During the preservice test period or before implementing inservice testing, an initial set of reference values shall be established for each pump. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Except as specified in para. ISTF-3310, only one preservice test is required for each pump. A set of reference values shall be established in accordance with para. ISTF-3300 for each pump required to be tested by this Subsection. Preservice testing shall be performed in accordance with the requirements of the following paragraphs:

(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTF-5110

(b) vertical line shaft centrifugal pump tests in accordance with para. ISTF-5210

(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTF-5310

(d) reciprocating positive displacement pump tests in accordance with para. ISTF-5310

ISTF-3200 Inservice Testing

Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see para. ISTF-1100). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:

(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTF-5120

(b) vertical line shaft centrifugal pump tests in accordance with para. ISTF-5220

(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTF-5320

(d) reciprocating positive displacement pump tests in accordance with para. ISTF-5320

ISTF-3300 Reference Values

Reference values shall be obtained as follows:

(a) Initial reference values shall be determined from the results of testing meeting the requirements of

[1] *Post-2000 plant:* a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

Table ISTF-3000-1 Inservice Test Parameters

Quantity	Preservice Test	Inservice Test	Remarks
Speed, N	X	X	If variable speed
Differential pressure, ΔP	X	X	Centrifugal pumps, including vertical line shaft pumps
Discharge pressure, P	X	X	Positive displacement pumps
Flow rate, Q	X	X	. . .
Vibration	X	X	Measure either V_d or V_v
Displacement, V_d	. . .	. . .	Peak-to-peak
Velocity, V_v	. . .	. . .	Peak

para. ISTF-3100, Preservice Testing, or from the results of the first inservice test.

(b) New or additional reference values shall be established as required by para. ISTF-3310 or ISTF-3320, or subpara. ISTF-6200(c).

(c) Reference values shall be established only when the pump is known to be operating acceptably.

(d) Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests.

(e) Reference values shall be established in a region(s) of relatively stable pump flow.

(1) Reference values shall be established within ±20% of pump design flow rate for the inservice test.

(2) Reference values shall be established within ±20% of pump design flow.

(f) All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with para. ISTF-3310 or ISTF-3320, or subpara. ISTF-6200(c).

(g) Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with para. ISTF-6400.

ISTF-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values. When a reference value or set of values may have been affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with para. ISTF-3300, or the previous value reconfirmed by an inservice test run before declaring the pump operable. The Owner shall determine whether the requirements of para. ISTF-3100, to reestablish reference values, apply. Deviations between the previous and new set of reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see section ISTF-9000).

ISTF-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable, for some reason other than stated in para. ISTF-3310, to establish an additional set of reference values, an inservice test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is acceptable per para. ISTF-6200, an additional set of reference values may be established as follows:

(a) For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in para. ISTF-5110 or ISTF-5210, as applicable. Vibration acceptance criteria shall be established by an inservice test at the new reference point. If vibration data was taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable.

(b) For positive displacement pumps, the additional set of reference values shall be established per para. ISTF-5310.

A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTF-9000). The requirements of para. ISTF-3300 apply.

ISTF-3400 Frequency of Inservice Tests

An inservice test shall be run on each pump quarterly.

ISTF-3410 Pumps in Regular Use. Pumps that are operated more frequently than every 3 months need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 months at the reference conditions, and the quantities specified were determined, recorded, and analyzed per section ISTF-6000.

ISTF-3420 Pumps in Systems Out of Service. For a pump in a system declared inoperable or not required to be operable, the test schedule need not be followed. Within 3 months before the system is placed in an operable status, the pump shall be tested and the test schedule followed in accordance with the requirements of this Subsection.

ISTF-3500 Data Collection

ISTF-3510 General

(a) *Accuracy.* Instrument accuracy shall be within the limits of Table ISTF-3510-1. If a parameter is determined

Table ISTF-3510-1 Required Instrument Accuracy

Quantity	Preservice and Inservice Tests, %
Pressure	±$\frac{1}{2}$
Flow rate	±2
Speed	±2
Vibration	±5
Differential pressure	±$\frac{1}{2}$

by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of Table ISTF-3510-1 (e.g., flow rate determination shall be accurate to within ±2% of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.

(b) Range

(1) The full-scale range of each analog instrument shall be not greater than 3 times the reference value.

(2) Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument.

(3) Vibration instruments are excluded from the range requirements of subparas. (b)(1) and (b)(2).

(c) Instrument Location. The sensor location shall be established by the Owner, documented in the plant records (see section ISTF-9000), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be either permanently mounted, or provision shall be made to duplicate their position during each test.

(d) Fluctuations. Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines.

(e) Frequency Response Range. The frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.

ISTF-3520 Pressure

(a) Gage Lines. If the presence or absence of liquid in a gage line could produce a difference of more than 0.25% in the indicated value of the measured pressure, means shall be provided to ensure or determine the presence or absence of liquid as required for the static correction used.

(b) Differential Pressure. When determining differential pressure across a pump, a differential pressure gage or a differential pressure transmitter that provides direct measurement of the pressure difference or the difference between the pressure at a point in the inlet and the pressure at a point in the discharge pipe shall be used.

ISTF-3530 Rotational Speed. Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of para. ISTF-3510.

ISTF-3540 Vibration

(a) On centrifugal pumps, except vertical line shaft pumps, measurements shall be taken in a plane approximately perpendicular to the rotating shaft in two approximately orthogonal directions on each accessible pump-bearing housing. Measurement shall also be taken in the axial direction on each accessible pump-thrust-bearing housing.

(b) On vertical line shaft pumps, measurements shall be taken on the upper motor-bearing housing in three approximately orthogonal directions, one of which is the axial direction.

(c) On reciprocating pumps, the location shall be on the bearing housing of the crankshaft, approximately perpendicular to both the crankshaft and the line of plunger travel.

(d) If a portable vibration indicator is used, the measurement points shall be clearly identified on the pump to permit subsequent duplication in both location and plane.

ISTF-3550 Flow Rate. When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. External recirculated flow is required to be measured if such flow is present during the design function of the pump.

ISTF-4000 TO BE PROVIDED AT A LATER DATE

ISTF-5000 SPECIFIC TESTING REQUIREMENTS

A preservice test may be substituted for any inservice test.

ISTF-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps)

(a) Duration of Tests. For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTF-3000-1 shall be made and recorded.

(b) Bypass Loops. A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in para. ISTF-3300.

ISTF-5110 Preservice Testing. The parameters to be measured are specified in Table ISTF-3000-1.

Table ISTF-5120-1 Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range Low	Required Action Range High
Inservice Test [Notes (1), (2)]	N/A	Q	0.94 to $1.06Q_r$	0.90 to $<0.94Q_r$	$<0.90Q_r$	$>1.06Q_r$
	N/A	ΔP	0.93 to $1.06\Delta P_r$	0.90 to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

(1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.

(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

(a) Flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTF-5120 Inservice Testing. Inservice tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTF-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) For centrifugal and vertical line shaft pumps, the resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTF-5120-1 and corrective action taken as specified in para. ISTF-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTF-5120-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-5200 Vertical Line Shaft Centrifugal Pumps

(a) Duration of Tests. For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTF-3000-1 shall be made and recorded.

(b) Bypass Loops. A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in para. ISTF-3300.

ISTF-5210 Preservice Testing. The parameters to be measured are specified in Table ISTF-3000-1.

(a) Flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point shall be used to compare the results of inservice tests.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTF-5220 Inservice Testing. Tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTF-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

Table ISTF-5220-1 Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range Low	Required Action Range High
Inservice Test [Notes (1), (2)]	N/A	Q	0.95 to $1.06Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	ΔP	0.95 to $1.06\Delta P_r$	0.93 to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript *r* denotes reference value, the subscript *v* denotes vibration velocity reference value, and the subscript *d* denotes displacement.

NOTES:

(1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.

(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

(b) The resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See Fig. ISTB-5223-1.)

(d) All deviations from the reference values shall be compared with the ranges of Table ISTF-5220-1 and corrective action taken as specified in para. ISTF-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTF-5220-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-5300 Positive Displacement Pumps

(a) Duration of Tests. For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTF-3000-1 shall be made and recorded.

(b) Bypass Loops. A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in para. ISTF-3300.

ISTF-5310 Preservice Testing. The parameters to be measured are specified in Table ISTF-3000-1.

(a) For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in Table ISTF-3000-1.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTF-5320 Inservice Testing. Tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTF-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives.

(b) The resistance of the system shall be varied until the discharge pressure equals the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTF-5320-1 or Table ISTF-5320-2, as applicable, and corrective action taken as specified in para. ISTF-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTF-5320-1. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required

Table ISTF-5320-1 Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice Test [Notes (1), (2)]	N/A	Q	0.95 to 1.06Q_r	0.93 to <0.95Q_r	<0.93Q_r	>1.06Q_r
	N/A	P	0.93 to 1.06P_r	0.90 to <0.93P_r	<0.90P_r	>1.06P_r
	<600 rpm	V_d or V_v	≤ 2.5V_r	>2.5V_r to 6V_r or >10.5 to 22 mils (266.7 to 558.8 μm)	None	>6V_r or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	≤2.5V_r	>2.5V_r to 6V_r or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	>6V_r or >0.7 in./sec (1.7 cm/s)

GENERAL NOTE: The subscript *r* denotes reference value, the subscript *v* denotes vibration velocity reference value, and the subscript *d* denotes displacement.

NOTES:
(1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.
(2) Refer to Fig. ISTB-5223-1 to establish displacement limits for pumps with speeds ≥600 rpm or velocity limits for pumps with speeds <600 rpm.

Table ISTF-5320-2 Reciprocating Positive Displacement Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice Test	N/A	Q	0.95 to 1.06Q_r	0.93 to < 0.95Q_r	< 0.93Q_r	> 1.06Q_r
	N/A	P	0.93 to 1.06P_r	0.90 to < 0.93P_r	< 0.90P_r	> 1.06P_r
	N/A	V_d or V_v	≤ 2.5V_r	> 2.5V_r to 6V_r	None	> 6V_r

GENERAL NOTE: The subscript *r* denotes reference value, the subscript *v* denotes vibration velocity reference value, and the subscript *d* denotes displacement.

action ranges of Table ISTF-5320-2. For example, if vibration exceeds either 6V_r or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-6000 MONITORING, ANALYSIS, AND EVALUATION

ISTF-6100 Trending

Test parameters shown in Table ISTF-3000-1, except for fixed values, shall be trended.

ISTF-6200 Corrective Action

(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, the frequency of testing specified in para. ISTF-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. (c).

(b) Action Range. If the measured test parameter values fall within the required action range of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. (c).

(c) Analysis. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, an analysis may be performed that supports the pump's continued use at the changed values. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The analysis shall also consider whether new reference values should be established and shall justify the adequacy of the new reference values, if applicable. The results of this analysis shall be documented in the record of tests (see section ISTF-9000).

ISTF-6300 Systematic Error

When a test shows measured parameter values that fall outside of the acceptable range of Table ISTF-5120-1,

Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.

ISTF-6400 Analysis of Related Conditions

If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed[2] and documented in the record of tests (see section ISTF-9000).

ISTF-7000 TO BE PROVIDED AT A LATER DATE

ISTF-8000 TO BE PROVIDED AT A LATER DATE

[2] Vibration measurements of pumps may be foundation, driver, or piping dependent. Therefore, if initial vibration readings are high and have no obvious relationship to the pump, then vibration measurements should be taken at the driver, at the foundation, and on the piping and analyzed to ensure that the reference vibration measurements are representative of the pump and the measured vibration levels will not prevent the pump from fulfilling its function.

ISTF-9000 RECORDS AND REPORTS

ISTF-9100 Pump Records

The Owner shall maintain a record that shall include the following for each pump covered by this Subsection:

(a) the name of the manufacturer, and the manufacturer's model and serial numbers or other identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) a copy of the pump manufacturer's operating limits

ISTF-9200 Test Plans

In addition to the requirements of paras. ISTA-3110 and ISTA-3160, the test plans and procedures shall include the following:

(a) type of each pump

(b) the hydraulic circuit to be used

(c) the location and type of measurement for the required test parameters

(d) the method of determining test parameter values that are not directly measured by instrumentation

ISTF-9300 Record of Tests

See para. ISTA-9230.

ISTF-9400 Record of Corrective Action

See para. ISTA-9240.

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Division 1, Mandatory Appendix I[1]
Inservice Testing of Pressure Relief Devices in Light-Water Reactor Nuclear Power Plants

I-1000 GENERAL REQUIREMENTS

I-1100 Applicability

The requirements of this Mandatory Appendix apply to certain pressure relief devices (included in Section III of the ASME Boiler and Pressure Vessel Code, hereinafter known as the BPV Code).

I-1120 Limitations

(a) The requirements of this Mandatory Appendix recognize differences between the installed operating conditions and the conditions under which a pressure relief device may be tested. For a specific pressure relief device design, if the parameter to be tested is dependent on conditions not specifically addressed by these requirements, the installed operating condition and the test condition shall be comparable, or proven correlations shall be applied.

(b) The requirements of this Mandatory Appendix apply only to pressure relief devices required for overpressure protection.

(c) The requirements of this Mandatory Appendix are not intended to demonstrate conformance to design specification requirements.

(d) The requirements of this Mandatory Appendix are not intended to verify or demonstrate all aspects of pressure relief device operation.

I-1200 Definitions

The following definitions are provided to ensure a uniform understanding of select terms used in this Mandatory Appendix. Definitions for other related pressure relief device terms can be found in Appendix I of ASME PTC 25, Pressure Relief Devices.

ambient temperature: the temperature range of the environment surrounding a pressure relief device at its installed plant location during the phase(s) of plant operation for which the device is required for overpressure protection.

assist device: a pneumatic, hydraulic, or mechanical device applied to a pressure relief valve for set-pressure testing to assist inlet static pressure in opening the valve.

auxiliary actuating device: a device requiring an external energy source to provide inservice remote actuation capability of a pressure relief valve with inlet static pressure below set-pressure.

bellows alarm switch: an electropneumatic switch used in pilot-operated pressure relief valves to detect a failure of the pressure integrity of the pilot bellows, the failure of which may prevent opening of the primary valve.

control rings: internal rings used to adjust the opening characteristic, blowdown, and lift of a pressure relief valve.

gag: a mechanical device installed on a pressure relief valve to restrict or prevent lift.

historical data form: a form for recording test results and maintenance history of a pressure relief device.

normal system operating conditions (fluid, pressure, temperature): system fluid, pressure, and temperature range during the phase(s) of plant operation for which that system is intended to function.

overpressure protection: the means by which components are protected from overpressure by the use of pressure relieving devices or other design provisions as required by the BPV Code, Section III, or other applicable construction codes.

power-actuated relief valve: a relief valve in which the major relieving device is combined with and controlled by a device requiring an external source of energy.

remote actuation: actuation of a pressure relief device through a generated signal rather than by inlet static pressure.

thermal relief application: a relief device whose only overpressure protection function is to protect isolated components, systems, or portions of systems from fluid expansion caused by changes in fluid temperature.

valve group: valves of the same manufacturer, type, system application, and service media.

I-1300 Guiding Principles

I-1310 General

(a) Operation and Maintenance Instructions. Complete operation and maintenance instructions shall be available for each device. This Mandatory Appendix shall

[1] This Mandatory Appendix contains requirements to augment the rules of Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants.

be supplemented by these operating and maintenance instructions.

(b) Valve Testing Frequency. A frequency for valve testing is required by this Mandatory Appendix to provide assurance of the valve operational readiness.

(c) Valve Disassembly. This Mandatory Appendix does not require valves or accessories to be disassembled or removed from their installed position.

(d) Visual Examination. Visual examinations shall be performed in accordance with the Owner's examination procedures and shall be documented.

(e) Acceptance Criteria. The Owner, based upon system and valve design basics or technical specification, shall establish and document acceptance criteria for tests required by this Mandatory Appendix.

I-1320 Test Frequencies, Class 1 Pressure Relief Valves

(a) 5-Yr Test Interval. Class 1 pressure relief valves shall be tested at least once every 5 yr, starting with initial electric power generation. No maximum limit is specified for the number of valves to be tested within each interval; however, a minimum of 20% of the valves from each valve group shall be tested within any 24-month interval. This 20% shall consist of valves that have not been tested during the current 5-yr interval, if they exist. The test interval for any installed valve shall not exceed 5 yr. The 5-yr test interval shall begin from the date of the as-left set-pressure test for each valve.

(b) Replacement With Pretested Valves. The Owner may satisfy testing requirements by installing pretested valves to replace valves that have been in service, provided that

(1) for replacement of a partial complement of valves, the valves removed from service shall be tested prior to resumption of electric power generation or

(2) for replacement of a full complement of valves, the valves removed from service shall be tested within 12 months of removal from the system

(c) Requirements for Testing Additional Valves. Additional valves shall be tested in accordance with the following requirements:

(1) For each valve tested for which the as-found set-pressure (first test actuation) exceeds the greater of either the plus/minus tolerance limit of the Owner-established set-pressure acceptance criteria of subpara. I-1310(e) or ±3% of valve nameplate set-pressure, two additional valves shall be tested from the same valve group.

(2) If the as-found set-pressure of any of the additional valves tested in accordance with subpara. (c)(1) exceeds the criteria noted therein, then all remaining valves of that same valve group shall be tested.

(3) The Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria established in subpara. (c)(1) or the Owner-established acceptance criteria for other required tests, e.g., the acceptance of auxiliary actuating devices, compliance with Owner's seat-tightness criteria, etc. Based upon this evaluation, the Owner shall determine the need for testing in addition to the minimum tests specified in subpara. (c) to address any generic concerns that could apply to valves in the same or other valve groups.

I-1330 Test Frequency, Class 1 Nonreclosing Pressure Relief Devices. Class 1 nonreclosing pressure relief devices shall be replaced every 5 yr unless historical data indicates a requirement for more frequent replacement.

I-1340 Test Frequency, Class 1 Pressure Relief Valves That Are Used for Thermal Relief Application. Tests shall be performed in accordance with para. I-1320, Test Frequencies, Class 1 Pressure Relief Valves.

I-1350 Test Frequency, Classes 2 and 3 Pressure Relief Valves Except PWR Main Steam Safety Valves (15)

(a) Test Interval

(1) The maximum allowable time between tests for any valve, with the exception of PWR main steam safety valves, shall not exceed 10 yr, starting with initial electric power generation.

(2) For valve groups containing only one valve, the valve shall be tested at least every 48 months.

(3) For valve groups containing more than one valve, a minimum of 20% of the valves from each valve group shall be tested within any 48-month interval. This 20% shall consist of valves that have not been tested during the current 10-yr test interval, if they exist.

The test interval shall begin from the date of the as-left set-pressure test for each valve. PWR main steam safety valves shall be tested in accordance with para. I-1320.

(b) Replacement With Pretested Valves. The Owner may satisfy testing requirements by installing pretested valves to replace valves that have been in service, provided that

(1) for replacement of a partial complement of valves, the valves removed from service shall be tested within 3 months of removal from the system or before resumption of electric power generation, whichever is later or

(2) for replacement of a full complement of valves, the valves removed from service shall be tested within 12 months of removal from the system

(c) Requirements for Testing Additional Valves. Additional valves shall be tested in accordance with the following requirements:

(1) For each valve tested for which the as-found set-pressure (first test actuation) exceeds the greater of either the ±tolerance limit of the Owner-established set-pressure acceptance criteria of subpara. I-1310(e) or ±3% of valve nameplate set-pressure, two additional valves shall be tested from the same valve group.

(2) If the as-found set-pressure of any of the additional valves tested in accordance with subpara. (c)(1)

exceeds the criteria noted therein, then all remaining valves of that same valve group shall be tested.

(3) The Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria established in subpara. (c)(1) or the Owner-established acceptance criteria for other required tests, such as the acceptance of auxiliary actuating devices, compliance with the Owner's seat-tightness criteria, etc. Based upon this evaluation, the Owner shall determine the need for testing in addition to the minimum tests specified in subpara. (c) to address any generic concerns that could apply to valves in the same or other valve groups.

I-1360 Test Frequency, Classes 2 and 3 Nonreclosing Pressure Relief Devices. Classes 2 and 3 nonreclosing pressure relief devices shall be replaced every 5 yr, unless historical data indicates a requirement for more frequent replacement.

I-1370 Test Frequency, Classes 2 and 3 Primary Containment Vacuum Relief Valves

(a) Tests shall be performed on all Classes 2 and 3 containment vacuum relief valves at each refueling outage or every 2 yr, whichever is sooner, unless historical data requires more frequent testing.

(b) Leak tests shall be performed on all Classes 2 and 3 containment vacuum relief valves at a frequency designated by the Owner in accordance with Table ISTC-3500-1.

I-1380 Test Frequency, Classes 2 and 3 Vacuum Relief Valves, Except for Primary Containment Vacuum Relief Valves. All Classes 2 and 3 vacuum relief valves shall be tested every 2 yr, unless performance data suggest the need for a more appropriate test interval.

I-1390 Test Frequency, Classes 2 and 3 Pressure Relief Devices That Are Used for Thermal Relief Application. Tests shall be performed on all Classes 2 and 3 relief devices used in thermal relief application every 10 yr, unless performance data indicate more frequent testing is necessary. In lieu of tests the Owner may replace the relief devices at a frequency of every 10 yr, unless performance data indicate more frequent replacements are necessary.

I-1400 Instrumentation

I-1410 Set-Pressure Measurement Accuracy. Test equipment (e.g., gages, transducers, load cells, calibration standards) used to determine valve set-pressure, shall have an overall combined accuracy not to exceed ±1% of the indicated (measured) set-pressure.

(15) I-2000 INTRODUCTION

Sections I-3000, I-4000, and I-5000 define the requirements for performance testing of pressure relief devices for boiling water reactor (BWR) and pressurized water reactor (PWR) nuclear power plants. The valves subject to examination and tests are categorized. Responsibilities, examination methods, examination techniques, test methods, examination and test frequencies, records, and maintenance requirements are defined. Replacement valves of the same valve group shall be tested to the requirements of paras. I-3100 and I-3400. Replacement valves, not of the same valve group previously used, shall be tested to the requirements of paras. I-3100 and I-3200.

I-3000 PRESSURE RELIEF DEVICE TESTING (15)

I-3100 Testing Before Initial Installation

I-3110 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for subparas. (b) through (d), provided the valve passes visual examination in accordance with the Owner's examination procedures:

(a) visual examination

(b) set-pressure determination

(c) accessories [see subparas. I-3310(d) through (h)]

(d) determination of compliance with the Owner's seat-tightness criteria

I-3120 Class 1 Safety Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for subparas. (b), (c), and (d), provided the valve passes visual examination in accordance with the Owner's examination procedures: (15)

(a) visual examination

(b) set-pressure determination

(c) testing of acccessories [see subparas. I-3320(d) through (f)]

(d) determination of compliance with the Owner's seat-tightness criteria

I-3125 Class 1 Power-Actuated Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for subparas. (b), (c), and (d), provided the valve passes visual examination in accordance with the Owner's examination procedures: (15)

(a) visual examination

(b) determination of functional capability

(c) testing of acccessories [see subparas. I-3325(d) and (e)]

(d) determination of compliance with the Owner's seat-tightness criteria

I-3130 Other Class 1 Pressure Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for subparas. (b) and (c), provided the valve passes visual examination in accordance with the Owner's examination procedures:

(a) visual examination

(b) set-pressure determination

(c) determination of compliance with the Owner's seat-tightness criteria

I-3140 Class 1 Nonreclosing Pressure Relief Devices. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3150 Classes 2 and 3 Pressure Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for subparas. (b) and (c), if the valve passes visual examination in accordance with the Owner's examination procedures:

(a) visual examination

(b) set-pressure determination

(c) determination of compliance with the Owner's seat-tightness criteria

I-3160 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The devices shall pass visual examination in accordance with the Owner's examination procedures.

I-3170 Classes 2 and 3 Vacuum Relief Valves. The valves shall pass visual examination in accordance with the Owner's examination procedures.

I-3200 Testing Before Initial Electric Power Generation

I-3210 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. After installation, safety valves and pilot-operated pressure relief valves equipped with auxiliary actuating devices shall be remotely actuated at reduced or normal system operating pressure to verify open and close capability. Set-pressure verification is not required. Actuation pressure of the auxiliary actuating device sensing element, where applicable, and electrical continuity shall have been verified.

(15) **I-3220 Class 1 Safety Valves.** Within 6 months before initial reactor criticality, each valve shall have its set pressure verified. For PWRs, set-pressure verification shall be determined by pressurizing the system up to the valve set pressure and opening the valve, or the valve may be tested at or below normal system operating pressures with an assist device.

(15) **I-3225 Class 1 Power-Actuated Relief Valves.** After installation, each valve shall be remotely actuated at normal system operating pressure to verify open and close capability.

I-3230 Other Class 1 Pressure Relief Valves. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3240 Class 1 Nonreclosing Pressure Relief Devices. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3250 Classes 2 and 3 Pressure Relief Valves (15)

(a) *PWR Main Steam Safety Valves.* Either before or after installation and within 6 months before initial reactor criticality, each valve shall be subjected to the following tests:

(1) verification of compliance with the Owner's set-pressure criteria

(2) verification of compliance with the Owner's seat-tightness criteria

(b) *Other Pressure Relief Valves.* Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3260 Classes 2 and 3 Nonreclosing Pressure Relief Devices. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3270 Classes 2 and 3 Vacuum Relief Valves

(a) After installation, these valves shall be actuated to verify open and close capability and performance of any pressure- and position-sensing accessories.

(b) Compliance with the Owner's seat-tightness criteria shall be verified.

I-3300 Periodic Testing

Periodic testing of all pressure relief devices is required. No maintenance, adjustment, disassembly, or other activity that could affect "as found" set-pressure or seat-tightness data is permitted prior to testing. Control ring adjustment is permitted per subparas. I-4110(g) and I-4120(g). Test frequencies are specified in paras. I-1320, I-1330, I-1340, I-1350, I-1360, I-1370, I-1380, and I-1390. When on-line testing is performed to satisfy periodic testing requirements, visual examination may be performed out of sequence.

I-3310 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. Tests before maintenance or set-pressure adjustment, or both, shall be performed for subparas. (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustments.

(a) visual examination

(b) seat-tightness determination,[2] if practicable

(c) set-pressure determination

(d) determination of electrical characteristics and pressure integrity of solenoid valve(s)

[2] This test need not be performed at the same pressure as the final seat tightness test. This test may be quantitative or qualitative, dependent on the observed condition. This test is primarily for gross determination of "as found" seat tightness.

(e) determination of pressure integrity and stroke capability of air actuator

(f) determination of operation and electrical characteristics of position indicators

(g) determination of operation and electrical characteristics of bellows alarm switch

(h) determination of actuating pressure of auxiliary actuating device sensing element, where applicable, and electrical continuity

(i) determination of compliance with the Owner's seat-tightness criteria

(15) **I-3320 Class 1 Safety Valves.** Tests before maintenance or set-pressure adjustment, or both, shall be performed for subparas. (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

(a) visual examination

(b) seat-tightness determination,[2] if practicable

(c) set-pressure determination

(d) determination of operation and electrical characteristics of bellows alarm switch

(e) verification of the integrity of the balancing device on balanced valves

(f) determination of operation and electrical characteristics of position indicators

(g) determination of compliance with the Owner's seat-tightness criteria

(15) **I-3325 Class I Power-Actuated Relief Valves.** Tests before maintenance shall be performed for subparas. (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

(a) visual examination

(b) seat-tightness determination, if practicable

(c) set-pressure determination

(d) verification of the integrity of the balancing device on balanced valves

(e) determination of operation and electrical characteristics of position indicators

(f) determination of compliance with the Owner's seat-tightness criteria

I-3330 Other Class 1 Pressure Relief Valves. Tests before maintenance or set-pressure adjustment, or both, shall be performed for subparas. (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

(a) visual examination

(b) seat-tightness determination,[2] if practicable

(c) set-pressure determination

(d) verification of the integrity of the balancing device on balanced valves

(e) determination of operation and electrical characteristics of position indicators

(f) determination of compliance with the Owner's seat-tightness criteria

I-3340 Class 1 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with para. I-1330. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3350 Classes 2 and 3 Pressure Relief Valves. Tests before maintenance or set-pressure adjustment, or both, shall be performed for subparas. (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

(a) visual examination

(b) seat-tightness determination,[2] if practicable

(c) set-pressure determination

(d) verification of the integrity of the balancing device on balanced valves

(e) determination of compliance with the Owner's seat-tightness criteria

I-3360 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with para. I-1360. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3370 Classes 2 and 3 Vacuum Relief Valves

(a) The valves shall be actuated to verify open and close capability, set-pressure, and performance of any pressure and position-sensing accessories.

(b) Compliance with the Owner's seat-tightness criteria shall be determined.

I-3400 Disposition After Testing or Maintenance

I-3410 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing, except as required by subpara. (d).

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced, in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of subpara. I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in para. I-3310, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Each valve with an auxiliary actuating device that has been removed for maintenance or testing and reinstalled after meeting the requirements of para. I-3310, shall have the electrical and pneumatic connections verified either through mechanical/electrical inspection or test prior to the resumption of electric

power generation. Main disk movement and set-pressure verification are not required.

(e) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

(15) **I-3420 Class 1 Safety Valves**

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of subpara. I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in para. I-3320, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

(15) **I-3425 Class I Power-Actuated Relief Valves**

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedure. Valves shall be adjusted to meet the acceptance criteria of subpara. 1-1310(e).

(c) Refurbished equipment shall be subjected to test(s) specified in para. I-3325, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3430 Other Class 1 Pressure Relief Valves (15)

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of subpara. I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in para. I-3330, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3440 Class 1 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with para. I-1330. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3450 Classes 2 and 3 Pressure Relief Valves

(a) Valves that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of subpara. I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in para. I-3350, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3460 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with para. I-1360. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3470 Classes 2 and 3 Vacuum Relief Valves

(a) Valves that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of subpara. I-1310(e).

(c) Valves that have been refurbished shall be subjected to the test(s) specified in para. I-3370.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

(15) I-4000 TEST METHODS

I-4100 Set-Pressure Testing

(15) I-4110 Steam Service

(a) Test Media. Valves designed to operate on steam, including safety valves designed for saturated steam service that are installed on a water-filled loop seal, shall be set-pressure tested with saturated steam. Alternative compressive fluids may be used as the test media, if correlation data between the alternative fluid and steam have been established. The requirements of para. I-4300 shall apply for testing with alternative test media.

(b) Accumulator Volume. The volume of the accumulator drum and the pressure source flow rate shall be sufficient to determine the valve set-pressure. Valves may have their lifts restricted during set-pressure testing.

(c) Assist Devices. Assist devices may be used for set-pressure testing, provided the accuracy complies with the requirements of para. I-1400.

(d) Thermal Equilibrium. Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) Ambient Temperature. The ambient temperature of the operating environment shall be simulated during the set-pressure test. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the operating and testing ambient temperatures shall comply with the requirements of paras. I-4320 and I-4330.

(f) Superimposed Back Pressure

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) Control Rings. Adjustment of control rings to ensure valve action is permitted. For set-pressure acceptance testing, control ring positions shall not be altered between successive openings. Adjusted control rings shall be returned to their proper operating position prior to return to service, as documented by the Owner.

(h) Time Between Valve Openings. A minimum of 5 min shall elapse between successive openings.

(i) Number of Tests. The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Any subsequent openings at the same set-point adjustment shall be within acceptance criteria.

I-4120 Compressible Fluid Services Other Than Steam (15)

(a) Test Media. Valves shall be tested with the normal system operating conditions. The test media temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. Alternative compressible fluids and different temperatures may be used, provided the requirements of para. I-4300 are met. Air or nitrogen may be substituted at the same temperature without alternative media testing per para. I-4300.

(b) Accumulator Volume. The volume of the accumulator drum and the pressure source flow rate shall be sufficient to determine the valve set-pressure. Valves may have their lifts restricted during set-pressure testing.

(c) Assist Devices. Assist devices may be used for set-pressure testing, provided the accuracy complies with the requirements of para. I-1400.

(d) Thermal Equilibrium. Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) Ambient Temperature. The ambient temperature of the operating environment shall be simulated during the set-pressure test. The ambient temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the operating and testing ambient temperatures shall comply with the requirements of paras. I-4320 and I-4330.

(f) Superimposed Back Pressure

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) Control Rings. Adjustment of control rings to ensure valve action is permitted. For set-pressure acceptance testing, control ring positions shall not be altered between successive openings. Adjusted control rings shall be returned to their proper operating position prior to return to service, as documented by the Owner.

(h) Time Between Valve Openings

(1) There is no required minimum time between openings when the temperatures of the test medium, valve body, and ambient conditions all are within 10°F (5.5°C) of each other.

(2) A minimum of 5 min shall elapse between successive openings for all other tests.

(i) Number of Tests. The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Any subsequent openings at the same set-point adjustment shall be within acceptance criteria.

I-4130 Liquid Service (15)

(a) Test Media. Valves shall be tested with the normal system operating conditions. The test media temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. Alternative liquids and different temperatures may be used, provided the requirements of para. I-4300 are met.

(b) Accumulator Volume. There is no requirement of minimum accumulator volume; however, the pressure tap for determining set-pressure shall be located at the valve inlet.

(c) Assist Devices. Assist devices to determine set-pressure are not permitted for liquid service pressure relief valves.

(d) Thermal Equilibrium. Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) Ambient Temperature. The ambient temperature of the operating environment shall be simulated during the set-pressure test. The ambient temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the operating and testing ambient temperatures shall comply with the requirements of paras. I-4320 and I-4330.

(f) Superimposed Back Pressure

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) Time Between Valve Openings

(1) There is no required minimum time between openings when the temperatures of the test medium, valve body, and ambient conditions all are within 10°F (5.5°C) of each other.

(2) A minimum of 5 min shall elapse between successive openings for all other tests.

(h) Number of Tests. The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Unless otherwise stated in the test procedure, valve opening pressure shall be that inlet pressure when a continuous, unbroken stream of liquid is emanating from the valve outlet.

I-4200 Seat Tightness Testing

Seat tightness testing shall be performed in accordance with the Owner's valve test procedure. Consideration shall be given to test media, temperature stability, and ambient temperature, as required in para. I-4100.

Seat tightness testing shall be performed using the same fluid used for set-pressure testing, except as provided by para. I-4300.

I-4210 Inlet Pressure. The inlet pressure for seat leak testing shall be in accordance with one of the following:

(a) maximum system operating pressure

(b) 90% of spring setting or 5 psig (34 kPa) below spring setting for valves having a spring set-pressure less than 50 psig (344 kPa)

(c) pressure established in Owner's valve test procedure

I-4220 Acceptable Seat Tightness Testing Methods. Table I-4220-1 provides acceptable methods. Other methods may be determined by the Owner.

I-4230 Acceptance Criteria for Seat Leakage Testing. Either the original valve equipment design specification criteria or acceptance criteria established by the Owner in the valve test procedure shall be used for valve seat leakage acceptance criteria.

I-4300 Alternative Test Media

Pressure relief devices may be subjected to set-pressure tests and seat-tightness tests using a test medium (fluid and temperature) other than that for which they are designed, provided the testing complies with paras. I-4310, I-4320, and I-4330.

I-4310 Correlation. Correlation of pressure relief device operation, with respect to the parameter under test, shall be established for the specified alternative media, as compared with the operating media.

I-4320 Certification of Correlation Procedure. The Owner shall ensure that the correlation established in accordance with the procedure will be of sufficient accuracy such that the pressure relief devices tested or adjusted, or both, using the alternate media, will comply with the acceptance criteria of the following:

(a) subparagraph I-1320(c) or I-1350(c) for determining the need to test additional valves

(b) subparagraph I-4110(i), I-4120(i), or I-4130(h) for testing or adjusting valves, or both, for reuse

(c) paragraph I-4230 for determining seat tightness

Results of the tests performed to verify the adequacy of the alternate test media correlation shall be documented.

I-4330 Procedure. A written procedure shall be prepared by the Owner or the Owner's designee and certified in accordance with the requirements of para. I-4320. The procedure shall specify all test parameters that affect correlation and shall include, but not be limited to, the following:

(a) specific description of test setup

(b) specific requirements for instrumentation

(c) specific requirements for assist equipment (if any)

(d) specific requirements for test operating conditions (e.g., device temperature, ambient temperature, ambient pressure, etc.)

Test parameters shall be listed (e.g., time between openings, number of tests, etc.)

I-5000 RECORDS AND RECORD KEEPING (15)

I-5100 Requirements

The Owner shall maintain a record that shall include the following for each valve covered by this Mandatory Appendix:

(a) the manufacturer and manufacturer's model and serial number, or other identifiers

(b) a copy or summary of the manufacturer's acceptance test report, if available

(c) preservice test results

I-5200 Record of Test

In addition to the requirements of para. ISTA-9230, if testing is performed in accordance with para. I-4300, a copy of the alternate test media correlation, test procedure, and documentation of results of test performed to verify the adequacy of the alternate test media shall be retained.

I-5300 Record of Modification and Corrective Action

In addition to the requirements of para. ISTA-9240, the following requirements shall be met:

(a) The Owner shall document all modifications performed or corrective actions taken that affect the set-pressure of pressure relief devices or valves. The

(15) **Table I-4220-1 Seat Tightness Testing Methods for Pressure Relief Devices**

Test Method	Service Fluid			Remarks
	Steam	Air/Gas	Liquids	
Audible/visible	X	X	X	. . .
API RP-527	X [Note (1)]	X [Note (1)]	. . .	. . .
Air/gas under water	X	X	. . .	. . .
Downstream temperature measurement	X	X	X	Installed valves only
Weighed condensate	X [Note (1)]	. . .	. . .	Min. 10 min test
Volumetric or weight measurement	. . .	. . .	X	Min. 10 min test
Cold bar	X [Note (2)]	. . .	. . .	. . .
Acoustic emission	X	X	X	. . .

NOTES:
(1) On exposed spring valves, care must be exercised to ensure against leakage past the valve stem and adjacent valve pieces.
(2) Defined as 1 in. diameter polished stainless steel bar at a temperature less than 100°F passed in the plane parallel to the outlet flange face.

documentation shall also include any recommendations or modifications suggested by the manufacturer. Modification or corrective action, as outlined, shall be recorded and maintained for the period of time as outlined in the Owner's technical specifications.

(b) Any device modification or adjustment that affects nameplate data shall be recorded on a data sheet. The modification or adjustment shall be made in accordance with the manufacturer's published information or shall have the concurrence of the manufacturer.

An additional nameplate, not bearing a Code symbol stamp, shall be installed to reflect the new data and reference to records maintained by the Owner outlining the modification.

I-6000 DELETED (15)

I-7000 DELETED (15)

I-8000 DELETED (15)

I-9000 DELETED (15)

Division 1, Mandatory Appendix II[1]
Check Valve Condition Monitoring Program

II-1000 PURPOSE

This Mandatory Appendix establishes the requirements for implementing and maintaining a check valve condition monitoring program as discussed in para. ISTC-5222.

II-2000 GROUPINGS

Groupings shall be determined by the Owner. Groupings shall be technically justified and shall be based on

(a) the intended purpose of the condition monitoring program (e.g., improve performance, or optimize testing, examination, and preventive maintenance activities)

(b) analysis of test results and maintenance history

(c) design characteristics, application, and service conditions

The Owner shall assess the significance to plant safety if an extended test or examination interval is planned.

The Owner should also consider the sample disassembly examination program grouping details of subpara. ISTC-5221(c).

II-3000 ANALYSIS

The Owner shall perform an analysis of the test and maintenance history of a valve or group of valves in order to establish the basis for specifying inservice testing, examination, and preventive maintenance activities. The analysis shall include the following:

(a) Identify any common failure or maintenance patterns.

(b) Analyze these patterns to determine their significance and to identify potential failure mechanisms:

(1) determine whether certain preventive maintenance activities would mitigate the failure or maintenance patterns

(2) determine whether certain condition monitoring tests such as nonintrusive testing are feasible and effective in monitoring for these failure mechanisms

(3) determine whether periodic disassembly and examination activities would be effective in monitoring for these failure mechanisms

(4) determine whether changes in the valve groupings are required

II-4000 CONDITION-MONITORING ACTIVITIES (15)

Valve obturator movement during applicable test or examination activities shall be sufficient to determine the bidirectional functionality of the moving parts. A full open exercise test, or an open test to the position required to perform its intended function (see para. ISTA-1100), is not required for this assessment.

(a) Performance Improvement Activities

(1) If sufficient information is not currently available to complete the analysis required in section II-3000, or if this analysis is inconclusive, then the following activities shall be performed at sufficient intervals over an interim period of the next 5 yr or two refueling outages, whichever is less, to determine the cause of the failure or the maintenance patterns:

(-a) Identify interim tests (e.g., nonintrusive tests) to assess the performance of the valve or the group of valves.

(-b) Identify interim examinations to evaluate potential degradation mechanisms.

(-c) Identify other types of analysis that will be performed to assess check valve condition.

(-d) Identify which of these activities will be performed on each valve in the group.

(-e) Identify the interval of each activity.

(2) Identify attributes that will be trended. Trending and evaluation of existing data must be used as the bases to reduce or extend the time interval between tests or examinations.

(3) Complete or revise the condition-monitoring program test plans (see section II-6000) to document the check valve program performance improvement activities and their associated frequencies.

(4) Perform these activities at their associated intervals until

(-a) sufficient information is obtained to permit an adequate evaluation of the specific application or

(-b) until the end of the interim period

(5) After performance, review those attributes that were selected for trending, along with the results of each activity to determine whether any changes to the program are required. If significant changes to the program are required, the program shall be revised prior to the performance of the next activity, and the applicable

[1] This Mandatory Appendix contains requirements to augment the rules of Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants.

requirements of sections II-2000, II-3000, and II-4000 shall be repeated.

(b) Optimization of Condition-Monitoring Activities

(1) If sufficient information is available to assess the performance adequacy of the check valve or the group of check valves, then the following activities shall be performed:

(-a) Identify the applicable preventive maintenance activities including their associated intervals that are required to maintain the continued acceptable performance of the check valve or group of check valves.

(-b) Identify the applicable examination activities including their associated intervals that will be used to periodically assess the condition of each check valve or group of check valves.

(-c) Identify the applicable test activities including their associated intervals that will be used to periodically verify the acceptable performance of each check valve or group of check valves.

(-d) Identify which of these activities will be performed on each valve in the group.

(-e) Identify the interval of each activity. Initial intervals shall be established using (b) provided that the condition-monitoring test and examination intervals consider plant safety and are supported by the trending and evaluation of generic and plant-specific performance data. Trending and evaluation shall be used to support the conclusion that the valve or group of valves is capable of performing its intended function(s) over the entire interval.

(-f) Interval extensions shall be limited to one fuel cycle or 2 yr, whichever is longer, per extension. All valves in a group-sampling plan must be tested or examined again, before the interval can be extended again, or until the maximum interval would be exceeded.

(-g) Intervals shall not exceed the maximum intervals shown in Table II-4000-1. The requirements of para. ISTA-3120, Inservice Examination and Test Interval, do not apply.

(2) Identify attributes that will be trended. Trending and evaluation of existing data must be used to reduce or extend the time interval between tests or examinations.

(3) Revise the test plans (see section II-6000) to document the optimized condition-monitoring program activities, and the associated intervals of each activity.

(4) Perform these activities at their associated intervals.

(5) After performance, review the results of each activity to determine whether any changes to the optimized condition-monitoring program are required. If significant changes are required, the program shall be revised prior to the performance of the next activity, and the applicable requirements of sections II-2000, II-3000, and II-4000 shall be repeated.

Changes to IST intervals must consider plant safety and be supported by trending and evaluating both generic and plant-specific performance data to ensure the component is capable of performing its intended function(s) over the entire interval.

Table II-4000-1 Maximum Intervals

Group Size	Maximum Interval, yr [Note (1)]
≥4	16
3	12
2	12
1	10

NOTE:

(1) The maximum interval was determined by how many interval extensions could be obtained based on an 18-month or 24-month fuel cycle. All of the valves had to be tested or examined within the maximum interval to be considered a valid extension.

II-5000 CORRECTIVE MAINTENANCE

If corrective maintenance is performed on a check valve, the analysis used to formulate the basis of the condition-monitoring activities for that valve and its associated valve group shall be reviewed to determine whether any changes are required. If significant changes are required, the program shall be revised and the applicable requirements of sections II-2000, II-3000, and II-4000 shall be repeated.

II-6000 DOCUMENTATION

The condition-monitoring program shall be documented and shall include the following information:

(a) list of valves in the program

(b) list of valves in each valve group

(c) dates valves were added/deleted to the program and the reason for their inclusion/deletion

(d) analysis forming the basis for the program

(e) identified failure or maintenance history patterns for each valve

(f) condition-monitoring program activities, including the trended attributes and the bases for the associated intervals for each valve or valve group

Division 1, Mandatory Appendix III[1] Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants

III-1000 INTRODUCTION

III-1100 Applicability

This Mandatory Appendix establishes the requirements for preservice and inservice testing to assess the operational readiness of active motor-operated valves (MOVs) in light-water reactor (LWR) power plants.

III-1200 Scope

See para. ISTC-1200.

III-2000 SUPPLEMENTAL DEFINITIONS

full cycle exercise: full stroke of the valve from and back to its initial position.

motor-operated valve (MOV): a valve and its associated electric motor driven mechanism for positioning the valve, including components that control valve action and provide position output signals.

MOV functional margin: the increment by which an MOV's available capability exceeds the capability required to operate the MOV under design basis conditions.

stem factor: the ratio of stem torque to stem thrust in rising-stem valves.

III-3000 GENERAL TESTING REQUIREMENTS

III-3100 Design Basis Verification Test

A one-time test shall be conducted to verify the capability of each MOV to meet its safety-related design basis requirements. This test shall be conducted at conditions as close to design basis conditions as practicable. Requirements for a design basis verification test are specified in applicable regulatory documents. Testing that meets the requirements of this Mandatory Appendix but conducted before implementation of this Mandatory Appendix may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.

(b) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an engineering analysis shall be documented that supports applicability to the in situ conditions.

(c) Justification for testing at conditions other than design basis conditions and for grouping like MOVs shall be documented by an engineering evaluation, alternate testing techniques, or both. Where design basis testing of the specific MOV being evaluated is impracticable, or not meaningful (provides no additional useful data), data from other MOVs may be used if justified by engineering evaluation. Sources for the data include other plant MOVs or test data published in industry testing programs. Where analytical techniques are used to verify design basis capability, those techniques shall be justified by an engineering evaluation.

(d) For certain valve types (i.e., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an engineering evaluation of operating experience may be used to verify design basis capability.

(e) The design basis verification test shall be repeated if an MOV application is changed, the MOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an engineering evaluation, alternative testing techniques, or both.

III-3200 Preservice Test

Each MOV shall be tested during the preservice test period or before implementing inservice testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Mandatory Appendix but conducted before implementation of this Mandatory Appendix may be used. Only one preservice test of each MOV is required unless, as

[1] This Mandatory Appendix contains requirements to augment the rules of Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants.

described in para. II-3400, the MOV has undergone maintenance that could affect its performance.

III-3300 Inservice Test

Inservice testing shall commence when the MOV is required to be operable to fulfill its required function(s), as described in para. III-1100, and shall be sufficient to assess changes in MOV functional margin consistent with section III-6000.

(a) MOVs may be grouped for inservice testing as described in para. III-3500.

(b) Inservice tests shall be conducted in the as-found condition. Activities shall not be conducted if they invalidate the inservice test results. If maintenance is needed between the inservice tests, see para. III-3400. As-found testing is not required prior to maintenance activities as long as the MOV is not due for an inservice test. If maintenance activities are scheduled concurrently with an MOVs inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity.

(c) The inservice testing program will include a mix of static and dynamic MOV performance testing. The mix of MOV performance testing may be altered when justified by an engineering evaluation of test data.

(d) Dynamic MOV performance testing is not required for certain valve types (i.e., ball, plug, and diaphragm valves), with acceptable operating experience.

(e) Remote position indication shall be verified locally during inservice testing or maintenance activities.

III-3310 Inservice Test Interval. The inservice test interval determination shall include the following:

(a) The inservice test interval shall be determined in accordance with para. III-6440.

(b) If insufficient data exist to determine the inservice test interval in accordance with para. III-6400, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer inservice test interval.

(c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per para. III-3400 may be used to satisfy this requirement.

III-3400 Effect of MOV Replacement, Repair, or Maintenance

When an MOV or its control system is replaced, repaired, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined, or the previously established inservice test values shall be confirmed before the MOV is returned to service. If the MOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required after replacement, repair, or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in section III-9000, Records and Reports.

III-3500 Grouping of MOVs for Inservice Testing

Grouping MOVs for inservice testing is permissible. Grouping MOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping MOVs:

(a) MOVs with identical or similar motor-operators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of MOVs shall be validated by appropriate inservice testing of one or more representative valves.

(b) Test results shall be evaluated and justified for all MOVs in the group.

III-3600 MOV Exercising Requirements

III-3610 Normal Exercising Requirements. All MOVs, within the scope of this Mandatory Appendix, shall be full cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 months. Full cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full stroke exercising of an MOV is not practical during plant operation or cold shutdown outages, full stroke exercising shall be performed during the plant's refueling outage. (15)

III-3620 Additional Exercising Requirements. The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

(a) MOVs with high risk significance

(b) MOVs with adverse or harsh environmental conditions or

(c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

III-3700 Risk-Informed MOV Inservice Testing

Risk-informed MOV inservice testing that incorporates risk insights in conjunction with performance margin to establish MOV grouping, acceptance criteria, exercising requirements and testing interval may be implemented.

III-3710 Risk-Informed Considerations. The Owner shall consider the following when incorporating risk insights in the inservice testing of MOVs:

(a) develop an acceptable risk basis for MOV risk determination

(b) develop MOV screening criteria to determine each MOVs contribution to risk

(c) finalize risk category by a documented evaluation from a Plant Expert Panel

III-3720 Risk-Informed Criteria. Each MOV shall be evaluated and categorized using a documented risk ranking methodology. This Mandatory Appendix provides test requirements for high and low safety significant component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

III-3721 HSSC MOVs. HSSC MOVs shall be tested in accordance with para. III-3300 and exercised in accordance with para. III-3600. HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer exercise interval is small.

III-3722 LSSC MOVs. In meeting the provisions of this Mandatory Appendix, including exercising in accordance with para. III-3600 and the determination of proper MOV test interval in section III-6000, risk insights shall be applied to inservice testing of LSSC MOVs by the following:

(a) LSSC grouping shall be technically justified, but the provision for similarity in subpara. III-3500(a) may be relaxed. The provisions in subpara. III-3500(b) related to evaluation of test results for MOVs in that group continue to be applicable to all MOVs within the scope of this Mandatory Appendix.

(b) LSSC MOVs may be associated with an established group of other MOVs. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with section III-6000, and applied to all LSSC MOVs associated with that group.

(c) LSSC MOVs that are not associated with an established group shall be inservice tested, in accordance with para. III-3300, using an initial test interval of three refueling cycles or 5 yr (whichever is longer) until sufficient data exist to determine a more appropriate test interval as described in para. III-6440.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with para. III-3310.

III-4000 TO BE PROVIDED AT A LATER DATE

III-5000 TEST METHODS

III-5100 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

III-5200 Test Conditions

Test conditions shall be sufficient to determine the MOV's functional margin per para. III-6400. Test conditions shall be recorded for each test per section III-9000.

III-5300 Limits and Precautions

Testing limits and precautions include the following:

(a) MOV exposure to dust, moisture, or other adverse conditions shall be minimized when normally enclosed compartment covers are removed while performing tests.

(b) Manufacturer or vendor limits and precautions associated with the MOV and with the test equipment shall be considered, including the structural thrust and torque limits of the MOV.

(c) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(d) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the MOV by the particular testing performed.

III-5400 Test Documents

Approved plant documents shall be established for all tests specified in this Mandatory Appendix and shall provide for

(a) methodical, repeatable, and consistent performance testing

(b) collection of data required to analyze and evaluate the MOV functional margin in accordance with section III-6000

III-5500 Test Parameters

Sufficient test parameters shall be selected for measurement to meet the requirements of section III-6000 in determining the MOV functional margin.

III-6000 ANALYSIS AND EVALUATION OF DATA

III-6100 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each MOV within the scope of this Mandatory Appendix. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the valve operating requirements. Thrust, torque, or other measured engineering parameters correlated to thrust or torque consistent with paras. III-6100 through III-6500, may be used to establish the acceptance criteria. Motor control center testing is acceptable if correlation with testing at the MOV has been established. When determining the acceptance criteria, consider the following sources of uncertainty:

(a) test measurement and equipment accuracy

(b) valve and actuator repeatability (e.g., torque switch repeatability)
(c) analysis, evaluation, and extrapolation method
(d) grouping method

III-6110 Parameter Measurements. MOV margins may be expressed in terms of stem force or other parameters, if those parameters are consistent with paras. III-6100 through III-6500.

III-6200 Analysis of Data

Data obtained from a test required by this Mandatory Appendix, shall be analyzed to determine if the MOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each MOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per para. III-6430, does not meet the acceptance criteria, the MOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

III-6300 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each MOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating MOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable MOVs to establish appropriate time intervals for future test activities.

III-6400 Determination of MOV Functional Margin

The Owner shall demonstrate that adequate margin exists between valve operating requirements and the available actuator output capability to satisfy the acceptance criteria for MOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in MOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

III-6410 Determination of Valve Operating Requirements. Design basis valve operating requirements, including stem factor for rising stem valves, shall be determined from

(a) measurements taken during testing at design basis conditions
(b) analytical methods using valve parameters determined from testing at conditions that may be extrapolated to design basis conditions or
(c) application of justified industry methodologies

III-6420 Determination of Actuator Output Capability

III-6421 Available Output Based on Motor Capabilities. Available actuator output shall be determined based on motor capabilities at the motor's design basis conditions. Considerations shall include

(a) rated motor start torque
(b) minimum voltage conditions
(c) elevated ambient temperature conditions
(d) operator efficiency
(e) other appropriate factors

III-6422 Available Output Based on Torque Switch Setting. Where applicable, the available output shall be determined based on the current torque switch setting.

For MOVs where testing does not sufficiently load the MOV to cause torque switch trip (e.g., butterfly and ball valves), available output based on the current torque switch setting shall be determined analytically from test data. Considerations shall include

(a) calibration of the torque switch spring pack
(b) the current torque switch setting
(c) repeatability of torque switch operation

III-6430 Calculation of MOV Functional Margin. MOV functional margin shall be calculated as the difference between the available actuator output and valve operating requirements. Available actuator output is determined as

(a) design basis motor operator capability for limit switch controlled strokes, or
(b) the lesser of design basis motor operator capability or motor operator capability at the current torque switch setting for torque switch controlled strokes

III-6440 Determination of MOV Test Interval. Calculations for determining MOV functional margin shall account for potential performance related degradation. Maintenance activities and associated intervals can affect test intervals and shall be considered. The inservice test interval shall be set such that the MOV functional margin does not decrease below the acceptance criteria.

III-6500 Corrective Action

If the MOV performance is unacceptable, as established in para. III-6400, corrective action shall be taken in accordance with Owner's corrective action requirements.

III-6510 Record of Corrective Action. The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.

III-7000 TO BE PROVIDED AT A LATER DATE

III-8000 TO BE PROVIDED AT A LATER DATE

III-9000 RECORDS AND REPORTS

III-9100 Test Information

Pertinent test information shall be recorded or verified for MOV testing, described in section III-3000. The following information shall be considered along with the information requirements in ISTA/ISTC:

(a) MOV plant-specific unique identification number.

(b) motor, valve, actuator nameplate data.

(c) test equipment unique identification numbers and equipment calibration dates.

(d) test method and conditions, described in section III-5000, including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, electric motor-operator orientation, and piping configuration near the MOV.

(e) breaker setting/fuse size and motor starter thermal overload size, if used.

(f) MOV torque and limit switch configuration and settings.

(g) MOV performance test procedure and other approved plant documents containing acceptance criteria.

(h) name of test performer and date of test.

(i) system flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.

(j) significant observations: any comments pertinent to the test results that otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic MOV action noted either during or preceding performance testing and any other pertinent design information that can be verified at the MOV.

III-9200 Documentation of Analysis and Evaluation of Data

The documentation of acceptable MOV performance, which has been analyzed and evaluated in accordance with section III-6000, shall include, as a minimum

(a) values of test data, test parameters, and test information established by paras. III-5500 and III-9100.

(b) summary of analysis and evaluation required per paras. III-6200 and III-6300.

(c) statement(s), by an individual qualified to make such a statement through the Owner's qualification requirements, confirming that the MOV is capable of performing its intended safety function.

(d) test results and analysis shall be evaluated by qualified individuals and documented to include signature and date. Independent verification shall be by individuals qualified to verify those specific analyses and evaluations through the Owner's qualification requirements.

Division 1, Mandatory Appendix IV
To Be Provided at a Later Date

Division 1, Mandatory Appendix V[1]
Pump Periodic Verification Test Program

V-1000 PURPOSE

This Mandatory Appendix establishes the requirements for implementing a pump periodic verification test. As discussed in ISTB-1400, the Owner shall establish a pump periodic verification test program for certain applicable pumps that are tested in accordance with para. ISTA-1100.

V-2000 DEFINITIONS

pump periodic verification test[2]*:* a test that verifies a pump can meet the required (differential or discharge) pressure as applicable, at its highest design basis accident flow rate.

V-3000 GENERAL REQUIREMENTS

The Owner shall

(a) identify those certain applicable pumps with specific design basis accident flow rates in the Owner's credited safety analysis (e.g., technical specifications, technical requirements program, or updated safety analysis report) for inclusion in this program

(b) perform the pump periodic verification test at least once every 2 yr

(c) determine whether the pump periodic verification test is required before declaring the pump operable following replacement, repair, or maintenance on the pump

(d) declare the pump inoperable if the pump periodic verification test flow rate and associated differential pressure (or discharge pressure for positive displacement pumps) cannot be achieved

(e) maintain the necessary records for the pump periodic verification tests, including the applicable test parameters (e.g., flow rate and associated differential pressure, or flow rate and associated discharge pressure, and speed for variable speed pumps) and their basis

(f) account for the pump periodic verification test instrument accuracies in the test acceptance criteria

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[1] This Mandatory Appendix contains requirements to augment the rules of Subsection ISTB, Inservice Testing of Pumps in Light Water Reactor Nuclear Power Plants. The Owner is not required to perform a pump periodic verification test, if the design basis accident flow rate in the Owner's safety analysis is bounded by the comprehensive pump test or Group A test.

[2] A pump may have several design basis postaccident operating points due to different system configurations or single vs. parallel pump operation. Reference ASME OM, Division 2, Part 28, Standard for Performance Testing of Systems in Light-Water Reactor Power Plants, for additional information on testing of power plant systems.

Division 1, Nonmandatory Appendix A[1]
Preparation of Test Plans

A-1000 PURPOSE

The purpose of this Nonmandatory Appendix is to provide guidance for the preparation of test plans to ensure adequate information for submittal to reviewing agencies. This Nonmandatory Appendix is not part of Subsection ISTA, General Requirements, but is included for informational purposes.

A-2000 TEST PLAN CONTENTS

A-2100 Background and Introduction

Test plans, which may consist of one or more parts (e.g., a part for general information and parts with details), should include the following:

(a) dates of test interval

(b) the edition and addenda of this Subsection used

(c) Code classification of components and boundaries of system classification including

(1) specific rules for classification

(2) lists of systems and identification of acronyms used

(d) summary tables for each system showing Code classification, type of components, and tests or examinations to be performed

(e) the Code requirements for each component that are not being satisfied by the tests or examinations, and justification for the substitute tests or examinations as discussed in section A-3000

(f) Code Cases proposed for use and the extent of their application

(g) a reference list of applicable documents, as required by para. A-2300

(h) names, signatures, and company affiliation of the preparers and approvers of the test plan

A-2200 Summary of Changes in Updated Test Plans

The following summary information should be included to describe changes in updated test plans:

(a) listing of new or revised procedures

(b) changes in exemptions, tests, or examinations

(c) changes in substitute tests or examinations of section A-3000

A-2300 Applicable Documents

Test plans should include a reference list of applicable documents. The following documents should be considered:

(a) 10 CFR 50

(b) edition and addenda of this Subsection that apply (if portions of different editions or addenda are selected, identify the related requirements and components selected for testing or examination for each edition and addenda)

(c) Code Cases

(d) other regulatory documents

(e) piping and instrument diagrams (P&IDs)

A-2400 Code Subsections

(a) Test plans should address the following Subsections:

(1) ISTB, pumps

(2) ISTC, valves

(3) ISTD, dynamic restraints (snubbers)

(b) Plans for Subsections may be combined in whole or part and published as one plan or as separate plans.

A-2500 Detailed Contents

Test plans should include the following:

(a) specific exemptions applied to each system covered by this Subsection

(b) list of components, including system identification, Code classification, and nominal size

(c) tables that provide details of tests or examinations (typical information to be included in these tables is shown in Supplements 1 through 3)

(d) a list of test and examination procedures including identification, titles, and general description of the components to which each procedure is applicable

A-3000 SUBSTITUTE TESTS AND EXAMINATIONS

A-3100 General

The following should be used when any Code requirement is not being satisfied by planned tests or examinations and when substitute tests or examinations[2] are included in the test plan.

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTA, General Requirements, it is not part of that Subsection.

[2] Substitute tests or examinations are tests or examinations that replace Code-required tests or examinations when the Code requirements are considered to be impractical.

A-3200 Justification of Substitute Tests and Examinations

Justification of substitute tests and examinations should include the following:

(a) Code Class

(b) Code test or examination requirements and identification of individual components for which substitute test or examinations are planned

(c) identification of the substitute tests or examinations that are planned

(d) frequency or schedule, as applicable, for the planned substitute tests or examinations including any plans for deferring the required tests or examinations

(e) documentation (drawings, sketches, or photographs may be used) of reasons the required tests or examinations are impractical, such as

(1) system or plant operating limitations

(2) inaccessibility

(3) equipment design

(4) radiation levels at the test or examination area

(5) total estimated man-REM exposure involved in the test or examination

(6) flushing or shielding capabilities that might reduce radiation levels

(7) considerations involving remote examination

(f) technical justification and data to support the substitute tests or examinations, including

(1) description and justification of any changes expected in the overall level of plant quality and safety by performing the proposed substitute tests or examinations in lieu of the Code requirements

(2) identification and discussion of similar components (in redundant systems or in the same system) to be tested or examined as substitutes

(3) percentage of the required tests or examinations that have been or will be completed on each component for which substitute tests or examinations are planned

(4) discussion of the consequences of failure of the component for which the substitute tests or examinations are planned

Division 1, Supplement to Nonmandatory Appendix A

AS-1000 SUPPLEMENT 1: INFORMATION FOR ISTB PUMP TEST TABLES

(a) identification of system, in system-by-system order
(b) Code classification
(c) identification of specific pumps to be tested
(d) reference to drawings locating the pumps
(e) identification of specific tests to be performed, such as speed, flow rate, pressure, and vibration
(f) test frequency or schedule, as applicable
(g) reference to Code requirements that are not being satisfied, and identification of substitute tests

AS-2000 SUPPLEMENT 2: INFORMATION FOR ISTC VALVE TEST TABLES

(a) identification of systems, in system-by-system order
(b) Code classification
(c) identification of specific valves to be tested
(d) reference to drawings locating the valves
(e) valve category and size
(f) specific information on the valves to be tested, including valve type, actuator type, normal position, stroke direction, test to be performed, plant operational mode at the time of test, and maximum stroke time
(g) test frequency or schedule, as applicable
(h) reference to Code requirements that are not being satisfied, and identification of substitute tests

AS-3000 SUPPLEMENT 3: INFORMATION FOR ISTD DYNAMIC RESTRAINT (SNUBBER) TABLES

(a) identification of systems, in system-by-system order
(b) Code classification
(c) individual dynamic restraints (snubbers) selected for test and examination
(d) reference to drawings locating dynamic restraints (snubbers)
(e) acceptance criteria for the tests and examinations
(f) test or examination methods
(g) test or examination frequency or schedule, as applicable
(h) reference to Code requirements that are not being satisfied, and identification of substitute tests or examinations

Division 1, Nonmandatory Appendix B[1]
Dynamic Restraint Examination Checklist Items

B-1000 PURPOSE

The purpose of this Nonmandatory Appendix is to provide examples of items normally included in a checklist used to verify preservice and inservice examination requirements. This Nonmandatory Appendix is not part of Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, but is included for informational purposes.

B-2000 EXAMPLES FOR PRESERVICE AND INSERVICE

Some examples of unacceptable attributes normally included in a checklist to verify preservice and inservice examination requirements are as follows:

(a) inadequate reservoir fluid level

(b) loose, missing, or incorrectly installed structural connections or fasteners

(c) vented reservoir oriented such that hydraulic fluid cannot gravitate to snubber

(d) corrosion or solid deposits that could result in unacceptable snubber performance

(e) deformed structural attachment or piston rod

(f) weld arc strikes, paint, weld slag, adhesive, or other deposits on piston rod or support cylinder that could result in unacceptable snubber performance

(g) spherical bearing not fully engaged in attachment lug

(h) inadequate position setting

B-3000 EXAMPLES FOR PRESERVICE ONLY

Some examples of additional unacceptable attributes normally included in a checklist to verify preservice examination requirements only are as follows:

(a) incorrect snubber load rating

(b) incorrect installed location

(c) incorrect installed orientation

(d) incorrect position setting

(e) incorrect snubber configuration

(f) inadequate swing clearance

(g) snubber installed with preset locking screws used for shipment only

(h) protective coverings or shipping plugs not removed

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[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Division 1, Nonmandatory Appendix C[1]
Dynamic Restraint Design and Operating Information

C-1000 PURPOSE

The purpose of this Nonmandatory Appendix is to provide guidance in the form of design and operating information, which may be useful in the development of inservice examination and testing programs for snubbers. This Nonmandatory Appendix is not part of Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, but is included for informational purposes.

C-2000 DESIGN AND OPERATING ITEMS

Some items of snubber design and operating information that may be useful in the development of an inservice examination and testing program are as follows:

(a) snubber operation and maintenance instructions including parts list

(b) design drawings showing snubber rating, location, orientation, pin-to-pin dimensions, and hot and cold settings

(c) procurement specifications

(d) snubber qualification and acceptance test results

(e) snubber application reports

(f) the desired reservoir fluid level as a function of piston location and spatial orientation

(g) the correlation of activation velocity, acceleration, and release rate at normal test temperatures to the range of operating temperatures expected so that the snubber may be normalized at test temperature to perform within a specified range when at its operating temperature

(h) method for measuring the position setting

(i) required fluid and seal material specification

(j) limiting environmental conditions affecting service

(k) drag force for each size and type snubber furnished

(l) the correlation of hydraulic snubber release rate at various loads and the acceleration limiting value of mechanical snubbers at various loads to justify testing at less than rated loads

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Division 1, Nonmandatory Appendix D[1]
Comparison of Sampling Plans for Inservice Testing of Dynamic Restraints

D-1000 PURPOSE

The purpose of this Nonmandatory Appendix is to provide information to enable the user to make comparisons of the sampling plans included in Subsection ISTD. This Nonmandatory Appendix is not part of Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, but is included for informational purposes.

D-2000 DESCRIPTION OF THE SAMPLING PLANS

For simplicity, sampling plans are referred to as the 10% plan and the 37 plan.

D-2100 The 37 Plan

The 37 plan has an "accept" line. The accept line is represented by the equation

$$N = 36.49 + 18.18C$$

where
C = number of unacceptable snubbers
N = number of snubbers tested

If the point plotted falls on or below the accept line, as shown in Subsection ISTD, Fig. ISTD-5431-1, testing of that group may be discontinued. If the accept region still has not been reached after testing between 100 and 200 snubbers, then the actual percent of population quality (C/N) should be used to indicate the probability of extended or 100% testing. A population quality of ≥ 5% failed snubbers will probably result in extended testing.

D-2200 The 10% Plan

The 10% plan is really a family of "accept" lines that follow the equation

$$N = 0.1n\ (1 + C/2)$$

where
n = the number of snubbers in the test population

The treatment of each accept line is the same as in the 37 plan.

D-3000 COMPARISON OF SAMPLING PLANS

To cover the wide range of numbers of snubbers and acceptable population quality expected in different plants, two sampling plans are permitted. Both sampling plans provide the required protection. Therefore, the selection of a plan may be based on the number of tests required without compromising safety. The group size effect for the two plans is specified in paras. D-3100 and D-3200.

D-3100 Up to 370 Snubbers

The 10% plan requires the least testing for smaller groups. For groups up to 370 snubbers, the 10% plan is preferred because less testing is required. Note that for a group of 370 snubbers, the 10% plan and the 37 plan both require the same number of tests.

D-3200 Above 370 Snubbers

For groups that have more than 370 snubbers, the 37 plan is preferred to the 10% plan. In this range, the 37 plan requires less testing than the 10% plan.

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Division 1, Nonmandatory Appendix E[1]
Flowcharts for 10% and 37 Snubber Testing Plans

E-1000 PURPOSE

This Nonmandatory Appendix presents the testing plans in a flowchart form to enable the user to understand the options available for the corrective actions when unacceptable snubbers are found. (See Figs. E-1000-1 and E-1000-2.)

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Fig. E-1000-1 Flowchart for 10% Snubber Testing Plan (ISTD-5300)

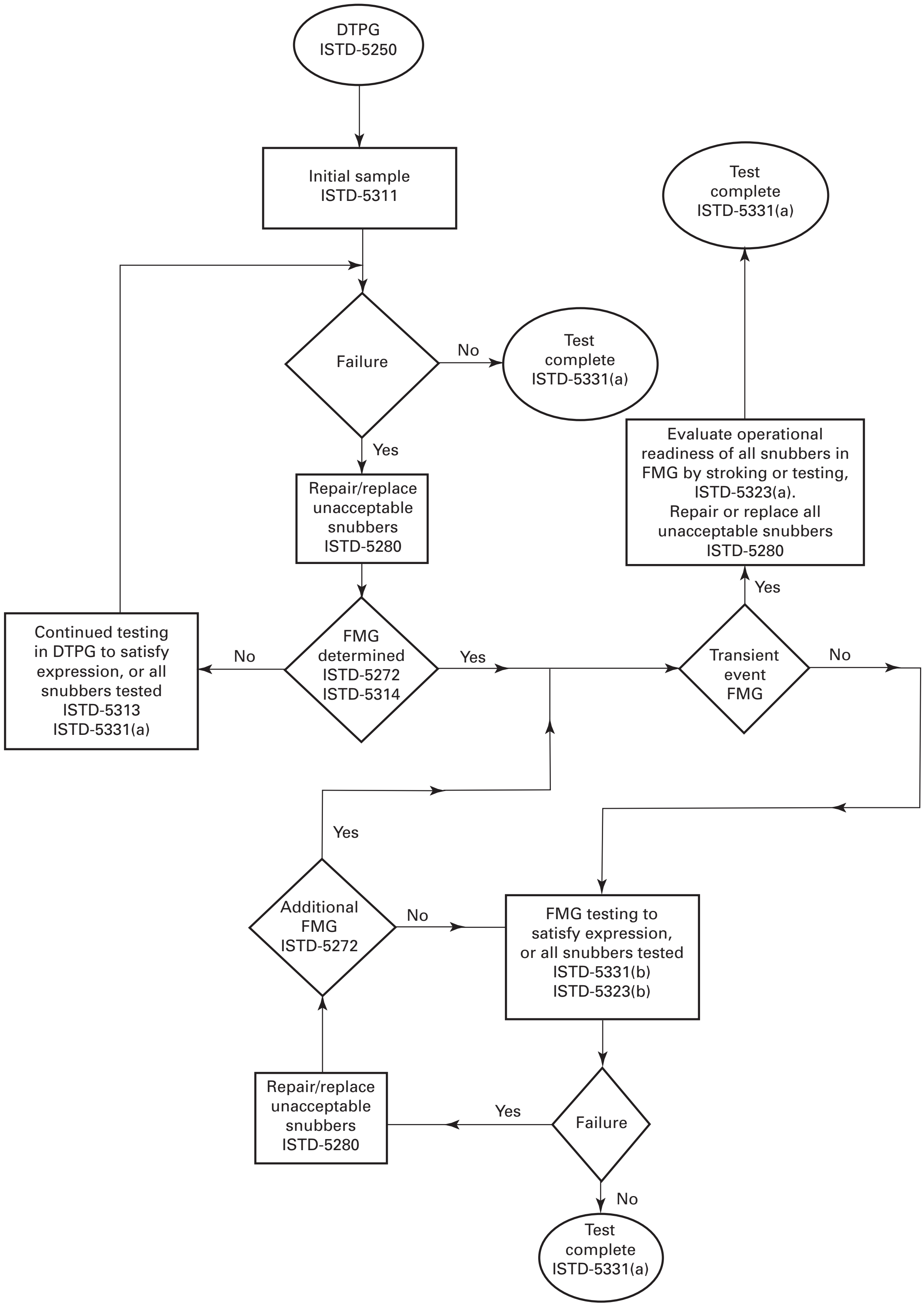
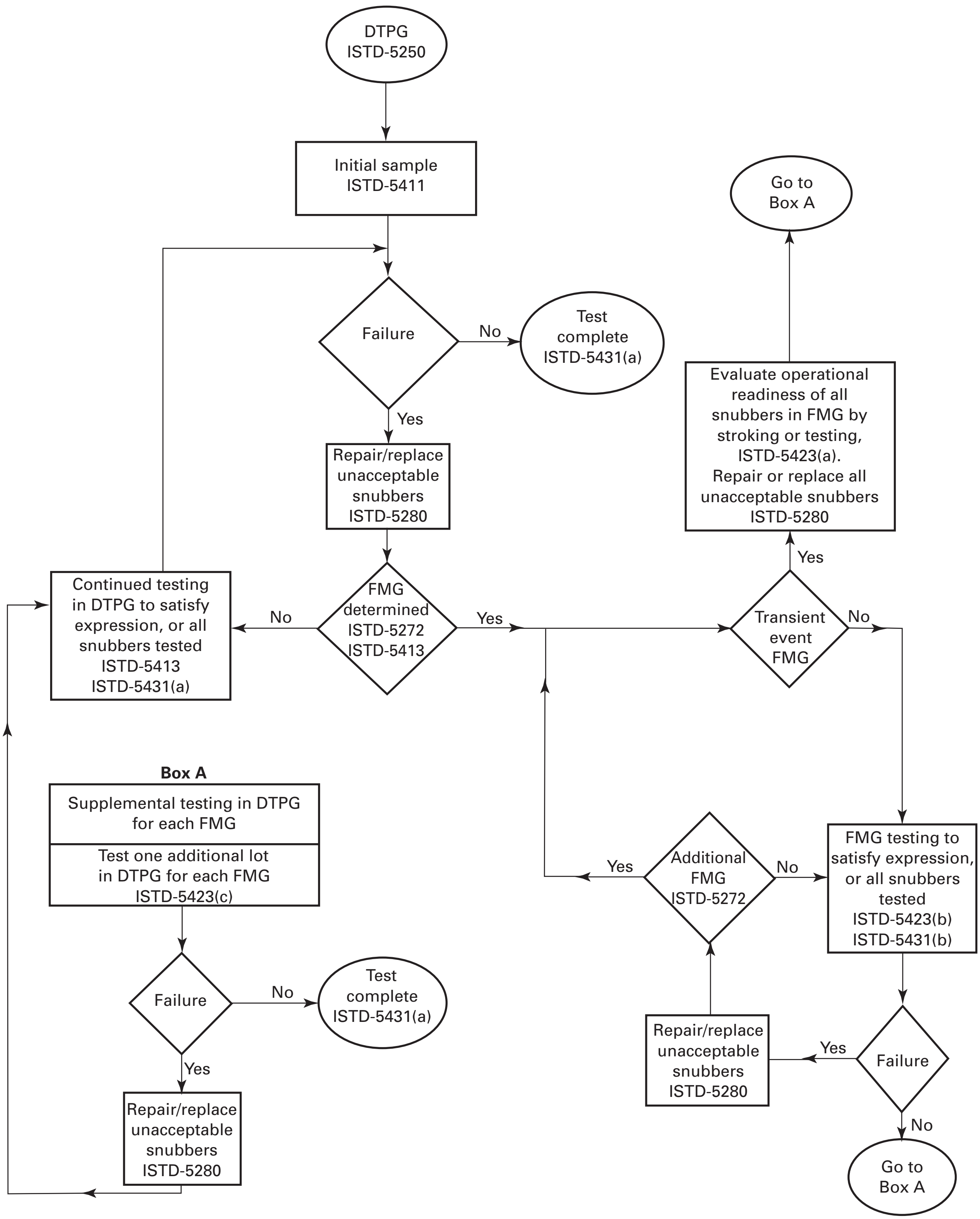


Fig. E-1000-2 Flowchart for 37 Snubber Testing Plan (ISTD-5400)



Division 1, Nonmandatory Appendix F[1] Dynamic Restraints (Snubbers) Service Life Monitoring Methods

F-1000 PURPOSE

Degradation due to service environment and maintenance errors can adversely affect snubber performance. This Nonmandatory Appendix discusses methods and considerations that can be used to predict and reevaluate snubber service life to optimize snubber availability during plant operation. The service life monitoring program should be based on knowledge of the operating environment, snubber design limits, and service records.

F-2000 PREDICTED SERVICE LIFE

Before start of service, snubber service life should be conservatively predicted, based on manufacturer recommendations or design review.

F-2100 Manufacturer Recommendations

Manufacturer recommendations may include seal and fluid replacement intervals for hydraulic snubbers or intervals for replacement of critical parts and/or lubricant for mechanical snubbers. Such intervals may vary, depending upon the application.

F-2200 Design Review

Snubber design review should consider materials, design features, and the plant operating environment. Evaluation of the effects of the environment on critical snubber parts such as seals, hydraulic fluids, lubricants, platings, etc., should be particularly emphasized.

F-3000 SERVICE LIFE REEVALUATION

Service life reevaluation should include the considerations discussed in paras. F-3100 through F-3320.

F-3100 Knowledge of the Operating Environment

Actual plant operating environments can differ significantly from original plant design specifications. Some snubbers may be subjected to localized high temperatures that are not representative of the general snubber population. Such applications may require augmented inspections or more frequent snubber overhaul or replacement than originally predicted.

On the other hand, the operating environment for the majority of snubbers may be significantly less severe than described in plant design specifications. Unnecessary overhaul or replacement of such snubbers may increase the incidence of snubber failure by introducing handling or maintenance errors.

It is important, therefore, that the operating environment be identified and an appropriate service life established. Environmental parameters may include the following:

(a) temperature
(b) vibration
(c) transient loading
(d) radiation
(e) humidity
(f) airborne contaminants
(g) leakage of adjacent components

Severe environments may be identified by plant operating data, direct measurement of environmental parameters, evaluation of the installed location [e.g., proximity to high-temperature components, or by examination of snubbers (or snubber parts)].

F-3110 Direct Measurement of Environmental Parameters. Various types of instrumentation and equipment are available for direct measurement of environmental parameters such as temperature, vibration, radiation, and humidity. Such equipment may be used for specific snubber locations where severe environments are expected or as an aid in determining the cause of snubber degradation.

F-3120 As-Found Testing. As-found testing of snubbers removed from service can identify degradation due to severe operating environments.

F-3200 Knowledge of Operating Environment Effects

Reevaluation of a snubber service life should include a thorough knowledge of the effects of various operating environments on snubber performance. Such knowledge may not be readily available from the manufacturer and may require engineering evaluation, including monitoring of trendable degradation parameters for snubbers removed from service. This might include periodic measurement of potentially trendable test parameters, e.g.,

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

drag force for selected snubbers. Periodic disassembly and evaluation of snubber internal parts (e.g., seals, springs fluid, etc., may also be required).

F-3210 Identification of Degraded Snubbers. Degraded snubbers may often be identified by visual examination of snubbers or snubber parts, by sampling of hydraulic fluid, or by evaluation of functional test data.

F-3220 Trending. The following should be considered for trending:

(a) establishment of trending parameters and associated baseline data

(b) trending parameters should relate directly to the anticipated failure mode

(c) reservoir fluid level is the most appropriate trending parameter for monitoring snubber leakage

(d) trends may be more effectively identified using average rather than peak drag force

F-3300 Cause Evaluation of Degraded or Failed Snubbers

Failures often result from influences not related to service time or service environment. Such influences include maintenance activities, construction activities, and manufacturing defects. It is important to ensure that service life is not unjustifiably influenced by such failures or degradation. Therefore, snubbers that failed inservice examinations or tests, and snubbers removed from service due to excessive degradation, should be evaluated to determine the cause of the degradation or failure.

F-3310 Failure Evaluation Data Sheet. Failure evaluation data sheets should include information pertaining to failure mode, failure mechanism, environment, service time, abnormal conditions, visual observations, test results, and test observations.

F-3320 Diagnostic Testing. Diagnostic testing may be useful in identifying the failure or degradation mechanism.

F-4000 SHORTENED SERVICE LIFE

It may be necessary to shorten the service life of snubbers subjected to severe environments, such as excessively high temperatures and vibration. Snubbers in severe environments may require augmented surveillance, including “hands-on” evaluations (e.g., stroking or in-situ monitoring).

F-5000 SERVICE LIFE EXTENSION

In many cases, where there has been minimal degradation due to the service environment, it may be appropriate to extend the previously established service life. Service life extension should be based on a technical evaluation of snubber performance that includes the current level of service-related degradation as well as the degradation rate.

F-6000 SEPARATE SERVICE LIFE POPULATIONS

Depending on the significance of environmental extremes from one area in the plant to another, separate and distinct service life populations may be appropriate.

Division 1, Nonmandatory Appendix G[1] Application of Table ISTD-4252-1, Snubber Visual Examination

G-1000 PURPOSE

This Nonmandatory Appendix provides guidance for use of Table ISTD-4252-1 to determine subsequent snubber examination interval.

G-2000 ASSUMPTIONS

The assumptions used are as follows:

(a) snubber population = 750 snubbers installed in the unit

(b) accessible portion of the population = 300

(c) inaccessible portion of the population = 450

(d) normal fuel cycle = 12 months

NOTE: Examination intervals may vary by ±25% (i.e., examination can be performed between 9 months and 15 months).

G-3000 CASE 1: EXAMINE ACCESSIBLE AND INACCESSIBLE SNUBBERS JOINTLY

If the decision is made to examine the snubber population without categorizing snubbers as accessible or inaccessible in accordance with para. ISTD-4220, then the total number of snubbers unacceptable to the visual examination requirement is used in Table ISTD-4252-1 to determine the next examination interval.

G-3100 Application of Column A

If the total number of unacceptable snubbers found during current examination is 20 or less, referring to population line for 750 snubbers and Column A, then, in accordance with Note (3) of Table ISTD-4252-1, the next examination interval is twice the previous interval but not greater than 48 months. If the previous examination interval was the normal fuel cycle, the examination during the next fueling outage may be skipped. Thus, the next examination is due at 24 months ±6 months (±25% of 24 months). If the number of unacceptable snubbers found at the next examination is equal to or less than the number in Column A, the interval may be doubled again, but not to exceed 48 months.

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

G-3200 Application of Column B

On the 750 population line, if the number of unacceptable snubbers is greater than 20 but less than or equal to 40, referring to Column B and Note (4), the next examination interval is the same as the previous interval (12 months).

G-3300 Application of Less Than or Equal to Column C and Recovery

If the number of unacceptable snubbers is greater than 40, but less than or equal to 78 (say 60), referring to Columns B and C and Note (5), then interpolation may be used or the interval is reduced to two-thirds of the previous interval. If the previous interval was the 12-month normal fuel cycle, then the next examination interval is $\frac{2}{3} \times 12 = 8$ months. Alternatively, for 60 unacceptable snubbers, interpolate between Columns B and C, i.e., examination interval

$$= \tfrac{2}{3} \times 12 + \left[\frac{(12 - 8)}{(78 - 40)} \times (78 - 60) \right]$$
$$= 8 + 1.89 = 9.89 \text{ months}$$

However, for determining the subsequent examination interval, use the previous interval as 8 months without interpolation, or 9.89 months when interpolation is used.

The number of unacceptable snubbers found during the subsequent examination done at an 8-month or 9.89-month interval will determine the next examination interval as follows:

If the number of unacceptable snubbers is

(a) less than or equal to Column A, the next examination interval is 2 × 8 months or 2 × 9.89 months

(b) greater than Column A but less than or equal to Column B, the next examination interval is 8 months or 9.89 months

(c) greater than Column B but less than or equal to Column C, the next examination interval is two-thirds of 8 months or two-thirds of 9.89 months, or interpolate between Columns B and C

G-3400 Application of Table When Number Exceeds Column C

For a population of 750 snubbers, if the number of unacceptable snubbers is greater than 78 (i.e., the number shown in Column C), then the next examination interval is two-thirds of the previous interval. If the previous interval was the normal fuel cycle of 12 months, the calculation is $\frac{2}{3} \times 12 = 8$ months.

G-4000 CASE 2: EXAMINE ACCESSIBLE AND INACCESSIBLE SNUBBERS SEPARATELY

If the decision was made to examine the accessible and inaccessible snubbers as separate categories, results are used separately in Table ISTD-4252-1.

G-4100 Determine the Values From Columns A Through C

The values for 300 snubbers are given in Table ISTD-4252-1. However, for the 450 inaccessible snubbers, interpolate to determine the number of unacceptable snubbers for each column. The interpolation may be applied whenever the exact population or category quantity is not given in Table ISTD-4252-1.

Snubbers	Column A	Column B	Column C
300 accessible	5	12	25
450 inaccessible	10	21	42

G-4200 Determine Subsequent Interval Separately

The number of unacceptable snubbers found in the accessible or inaccessible category shall determine the next examination interval for each category separately. The process for each is the same as discussed in section G-3000. For example

(a) if the number of unacceptable snubbers in the accessible category is 10 (greater than Column A but less than or equal to Column B), then the next examination interval for the accessible category is the previous interval

(b) if the number of unacceptable snubbers in the inaccessible category is 6 (less than or equal to Column A, which is 10 for 450 snubbers), then the next interval for the inaccessible category is twice the previous interval

G-4300 Recombining Categories Into One Population

If the accessible and inaccessible categories have different intervals for the subsequent examination, they may be examined jointly at the shorter examination interval required by either category. Use the shorter interval as the previous interval in determining the subsequent examination interval for the entire population.

Division 1, Nonmandatory Appendix H[1]
Test Parameters and Methods

H-1000 PURPOSE

This Nonmandatory Appendix provides guidelines for establishing snubber functional test methods that will produce information compatible with Subsection ISTD requirements. These guidelines do not preclude any particular test equipment or method. Manufacturer recommendations should be considered. EPRI Report No. TR-102363, Evaluation of Snubber Functional Test Methods, July 1993, provides additional guidance.

H-2000 TEST VARIABLES

Snubber functional testing involves three test variables. These variables are force, displacement, and time. All snubber test parameters are measured in terms of one or more of these variables. For example, velocity is measured as change in displacement per unit time, acceleration is measured as change in velocity per unit time.

Snubber functional tests involve measuring at least one of these variables as a dependent variable, while controlling at least one of the other variables.

H-3000 TEST PARAMETER MEASUREMENT

Subsection ISTD requires measurement of one or more of the following parameters:

(a) drag force
(b) activation
(c) release rate

H-3100 Drag Force Measurement

Drag force is measured by controlling the snubber stroke displacement while measuring the resulting resistance force. Generally, the rate of change in displacement (velocity) is also controlled.

H-3200 Activation Measurement

Activation applies to snubbers that have two distinct operating modes (i.e., activated and inactivated). Activation may involve control valve closure for a hydraulic snubber or engagement of a braking mechanism for a mechanical snubber. The three activation parameters are discussed in paras. H-3210 through H-3230.

H-3210 Locking Velocity. Locking velocity is measured by stroking the snubber at a gradually increasing velocity. Generally, the rate of change in velocity (ramp rate) is also controlled. Locking velocity is determined by recording stroke velocity at the point of control valve closure. Control valve closure may be identified using a number of indicators including the point of sudden force increase.

H-3220 Velocity Threshold. Velocity threshold is measured by stroking the snubber at a velocity sufficient to activate the velocity limiting mechanism. After activation, a specified constant force is applied. Velocity threshold is determined by recording the average stroke velocity over a specified time period or stroke distance, after the force stabilizes at the specified value. This applies to a velocity-limiting device.

H-3230 Acceleration Threshold. Acceleration threshold is measured by stroking at an acceleration sufficient to activate the acceleration limiting mechanism. After activation, a specified force is applied. Acceleration threshold is determined by recording the average acceleration over a specified time period or stroke distance, after the force stabilizes at the specified value. This applies to an acceleration-limiting device.

H-3300 Release Rate Measurement

Release rate is measured by applying a specified constant force to the snubber while measuring the resulting stroke velocity. Release rate is determined by recording the average stroke velocity over a specified time period or stroke distance, after the force stabilizes at the specified value.

H-4000 GENERAL TESTING CONSIDERATIONS

Snubber functional testing may involve the use of more than one test machine. Test results are subject to some variation due to a number of influences, including differences in instrumentation, the magnitude of controlled variables, variations in test machine control methods, environmental influences, and variations in data interpretations.

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

H-4100 Drag Test Velocity

For some snubber models, drag force is sensitive to test velocity. Test velocity should therefore be representative of the anticipated thermal movement rate of the components to which the snubbers are attached. Establishing standard drag test velocities will also facilitate identification of trends.

NOTE: For acceleration-limiting snubbers, the ramp rate (acceleration) to the desired drag test velocity should be maintained at a level that is less than anticipated activation threshold.

H-4200 Test Force

H-4210 Effect on Release Rate. The relationship between release rate and test force is generally consistent and predictable. Release rates measured at any test force can generally be reliably converted to the associated release rate value at the specified test force using empirically derived correlation curves or equations. For example, the release rate of a snubber tested at 60% of rated load may be converted to the corresponding release rate at 100% of rated load.

H-4220 Effect on Activation. Locking velocity is unaffected by test force because the test force is not applied until after activation. Velocity threshold and acceleration threshold, on the other hand, are measured while applying a force to the snubber. For these parameters, the effect of variations in test force should be established for each snubber model, for either correlation purposes, or for verification that the parameter is unaffected by such variations.

H-4300 Velocity Ramp Rate

Locking velocity test results may be affected by velocity ramp rate (the rate of increase of stroke velocity). Results of locking velocity tests conducted at a ramp rate less than 2 in./min/sec will generally be unaffected in this regard.

H-4400 Data Recording

A continuous recording of test variables should be performed. This data will assist in verification of the test results and resolution of any snubber performance anomalies.

H-4500 Verification of Test Results

Some test machines calculate and print test results automatically. Manual verification of automatically generated results will help validate the printouts. See also para. H-4400.

Division 1, Nonmandatory Appendix J[1]
Check Valve Testing Following Valve Reassembly

J-1000 PURPOSE

The purpose of this Nonmandatory Appendix is to provide guidance for determining the appropriate post-maintenance testing for check valves discussed in subpara. ISTC-5221(c).

J-2000 POSTDISASSEMBLY TEST RECOMMENDATIONS

When a check valve is disassembled and examined because it is impractical to verify it open or close, verifying the proper reassembly of the valve should not require performance of the impractical test. Since an examination is not a test, the test matrix, shown in Table J-2000-1, was developed to help the Owner establish post-maintenance testing requirements. Some of the examples recommend a demonstration of the nonsafety function (e.g., if a valve is disassembled because closure cannot be demonstrated, then an open test to at least partially open the obturator is recommended). Disassembly and examination activities cannot be used to satisfy a leakage test requirement. If postmaintenance testing is not practicable, the Owner should take other appropriate actions to ensure proper reassembly.

J-3000 TEST MATRIX

The test matrix, shown in Table J-2000-1, provides recommendations for the Owner's use in establishing postmaintenance test requirements. Where multiple recommendations are provided, the recommendations are listed in order of preference.

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Table J-2000-1 Check Valve Test Matrix

Valve Exercise Requirement	Reason for Disassembly	Postmaintenance Testing Recommendation
Safety Function:		
Open	Cannot achieve flow to fulfill its intended function	1. Perform an open test to partially open the obturator, if practicable 2. If a seat leakage requirement exists, do the leakage test 3. Perform a closure test
Close	Cannot verify closure	Perform an open test to at least partially open the obturator, if practicable
Open and Close	Cannot achieve flow to fulfill its intended function	1. Perform an open test to partially open the obturator, if practicable 2. If a seat leakage requirement exists, do the leakage test 3. Perform a closure test
Open and Close	Cannot verify closure	Perform an open test to at least partially open the obturator, if practicable
Open and Close	Cannot achieve flow to fulfill its intended function, and cannot verify closure	Perform an open test to partially open the obturator, if practicable

Division 1, Nonmandatory Appendix K[1]
Sample List of Component Deterministic Considerations

K-1000 PURPOSE

This Nonmandatory Appendix provides guidance to the Plant Expert Panel for categorizing components as HSSC or LSSC.

K-2000 SAMPLE DETERMINISTIC CONSIDERATIONS

K-2100 Design Basis Analysis

(a) Is the component considered in design basis analysis?
(b) Is the component function considered important in the Safety Analysis Report?
(c) Are there any technical specification considerations for this component?

K-2200 Radioactive Material Release Limit

(a) Could the failure of this component be considered a breach in an engineered safety barrier?
(b) Could the failure of this component result in an uncontained release of radioactive material in excess of that allowed?

K-2300 Maintenance Reliability

(a) Is the component important to maintaining system reliability?
(b) What type of component failures have been experienced for this and similar style components?
(c) What does the maintenance history indicate about the reliability of this component?
(d) Does the component receive preventive maintenance, and is it effective for preventing identified failures?
(e) How are component failures detected?

K-2400 Effect of Component Failure on System Operational Readiness

(a) Is the component important to maintaining system availability?
(b) How does component failure affect system performance?
(c) Does component failure cause other system component failures?
(d) What is the system component level of defense in depth?
(e) Does the system or component perform other functions outside the scope of the PRA?
(f) Can system or component failure modes affect redundant trains or other similar components?

K-2500 Other Deterministic Considerations

(a) Should other component failure modes be considered in the PRA model?
(b) Is this component used to mitigate the consequences of an accident caused by external events?
(c) Is this component important for safe shutdown?
(d) Is this component required to maintain the safe shutdown condition?
(e) Should other component failure modes that may not be included in the PRA be considered (e.g., aging effects, structural supports, human performance failures)?

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTE, Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Division 1, Nonmandatory Appendix L[1]
Acceptance Guidelines

L-1000 PURPOSE

This Nonmandatory Appendix provides guidance on the decision criteria for aggregate risk limits using CDF and LERF.

L-2000 ACCEPTANCE GUIDELINES

L-2100 Background and Introduction

The risk acceptance guidelines presented in this Nonmandatory Appendix are structured as follows. Regions are established in the two planes generated by a measure of the baseline risk metric (CDF or LERF) along the *x*-axis, and the change in those metrics (ΔCDF or ΔLERF) along the *y*-axis (Figs. L-2100-1 and L-2100-2). Acceptance guidelines are established for each region as discussed below. These guidelines are intended for comparison with a full PRA scope (including internal events, external events, full power, low power, and shutdown) assessment of the change in risk metric, and, when necessary, as discussed below, the baseline value of the risk metric (CDF or LERF). However, it is recognized that many PRAs are not full scope, and the use of less than full scope PRA information is acceptable as discussed in this subsection.

There are two acceptance guidelines, one for CDF and one for LERF, both of which should be used.

L-2110 Acceptance Guidelines for CDF. The acceptance guidelines for CDF are as follows:

(a) If the change can be clearly shown to result in a decrease in CDF, then the change is satisfactory.

(b) When the calculated increase in CDF is very small, which is taken as being less than 1E−06 per reactor year, the change should be considered regardless of whether there is a calculation of the total CDF (Region III). While there is no requirement to calculate the total CDF, should there be an indication that the CDF may be considerably higher than 1E−04 per reactor year, then the focus should be on finding ways to decrease CDF. Such an indication would result, for example, if

(1) the contribution to CDF calculated from a limited scope analysis, such as the PRA, and, if appropriate, the PRA with external initiating events, significantly exceeds 1E−04

(2) there has been an identification of a potential vulnerability from a margins type analysis or

(3) historical experience at the plant in question has indicated a potential safety concern

(c) When the calculated increase in CDF is in the range of 1E−06 per reactor year to 1E−05 per reactor year, changes should only be considered if it can be reasonably shown that the total CDF is less than 1E−04 per reactor year (Region II).

(d) Applications that result in increases to CDF above 1E−05 per reactor year (Region I) should not normally be considered.

L-2120 Guidelines for LERF. The guidelines for LERF are as follows:

(a) If the change can be clearly shown to result in a decrease in LERF, then the change is satisfactory.

(b) When the calculated increase in LERF is very small, which is taken as being less than 1E−07 per reactor year, the change should be considered regardless of whether there is a calculation of the total LERF (Region III). While there is no requirement to calculate the total LERF, should there be an indication that the LERF may be considerably higher than 1E−05 per reactor year, then the focus should be on finding ways to decrease rather than increase it. Such an indication would result, for example, if

(1) the contribution to LERF calculated from a limited scope analysis, such as that the IPE, and, if appropriate the IPEEE, significantly exceeds 1E−05

(2) there has been an identification of a potential vulnerability from a margins type analysis or

(3) historical experience at the plant in question has indicated a potential safety concern

(c) When the calculated increase in LERF is in the range of 1E−07 per reactor year to 1E−06 per reactor year, changes should only be considered if it can be reasonably shown that the total LERF is less than 1E−05 per reactor year (Region II).

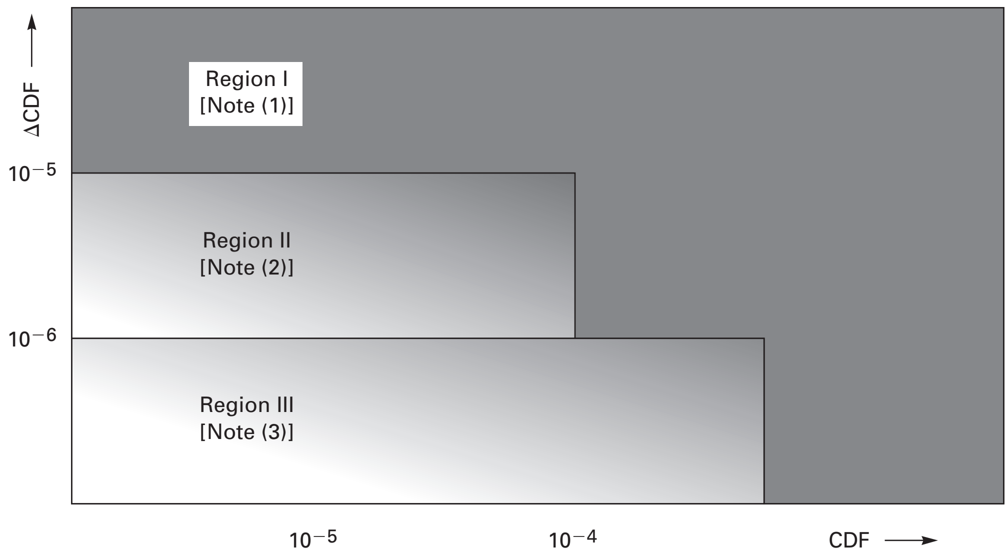
(d) Changes that result in increases to LERF above 1E−06 per reactor year (Region I) should not normally be considered.

L-2130 Additional Guidelines. These acceptance criteria are intended to provide assurance that proposed increases in CDF and LERF are small.

The analysis may be subject to a more detailed technical and management review depending upon the degree to which a change resides in a given region. In the context

[1] This Nonmandatory Appendix is included for informational purposes only. While it is related to Subsection ISTE, Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants, it is not part of that Subsection.

Fig. L-2100-1 Acceptance Guidelines for CDF (From RG 1.174)

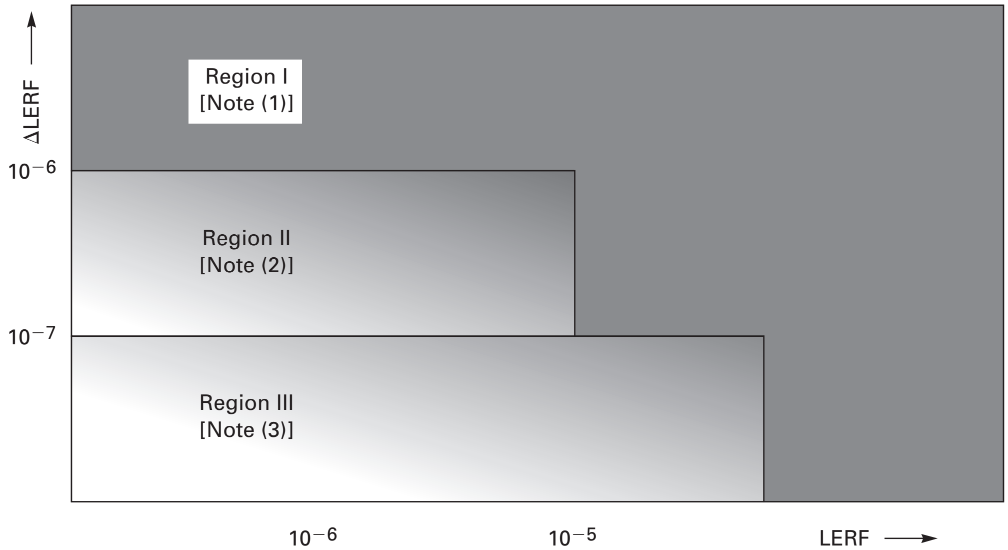


NOTES:
(1) Region I: No changes allowed.
(2) Region II:
  (a) Small changes
  (b) Track cumulative impacts
(3) Region III:
  (a) Very small changes
  (b) More flexibility with respect to baseline CDF
  (c) Track cumulative impacts

of the integrated decision making by the Plant Expert Panel, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as being absolute.

As indicated by the shading on the figures, the change request should be subject to a technical and management review that becomes more intensive the closer the calculated results are to the region boundaries.

Fig. L-2100-2 Acceptance Guidelines for LERF (From RG 1.174)



NOTES:
(1) Region I: No changes allowed.
(2) Region II:
  (a) Small changes
  (b) Track cumulative impacts
(3) Region III:
  (a) Very small changes
  (b) More flexibility with respect to baseline LERF
  (c) Track cumulative impacts

Division 1, Nonmandatory Appendix M Design Guidance for Nuclear Power Plant Systems and Component Testing

M-1000 PURPOSE

This Nonmandatory Appendix provides guidance for the design of systems and components in nuclear power plants to support preservice and inservice testing in accordance with the requirements of Divisions 1 through 3 of ASME OM. The guidance is intended to support design activities for new plant construction, but can be considered for existing plant systems.

M-2000 BACKGROUND

Nuclear power plants are required to comply with the requirements for preservice and inservice testing set forth in the applicable edition of ASME OM, Division 1. In the past, Code applicability has caused Owners to obtain relief from some of these requirements or to perform costly modifications due to limitations in design or construction. With the inception of a new generation of nuclear power plants, it is prudent that these limitations be eliminated during the design phase.

In addition, Divisions 2 and 3 of ASME OM have been developed to provide guidance for performance testing of various plant systems and components. The design of new nuclear power plants provides an opportunity to enhance testability through incorporation of appropriate design features.

This Nonmandatory Appendix is intended to support design organizations and is specifically intended to advise personnel responsible for the design of these plants regarding the provisions that should be considered when designing systems and components that will subsequently be subject to ASME OM requirements for preservice and inservice testing. Specific guidance is provided for selected parts of Divisions 1 through 3 of ASME OM for initial plant design.

M-3000 GUIDANCE

Lessons learned from nuclear power plant operating experience, industry degradation-monitoring programs for systems and components, and regulatory testing programs have revealed the need for an effective design and qualification process to allow the preservice and inservice testing programs to properly assess the operational readiness of plant components to perform their safety functions. To address this need, design personnel should establish an effective design and qualification process for pumps, valves, and dynamic restraints. ASME QME-1-2007[1] incorporates lessons learned from nuclear power plant operating experience and testing programs for the design and qualification of mechanical equipment to be used in nuclear power plants. ASME QME-1-2007 provides one approach for the functional design and qualification of pumps, valves, and dynamic restraints.

M-3100 General Test Capability Guidance

(a) Identify the components and systems that require testing based upon review of the Scope statements of Divisions 1 through 3 of ASME OM with consideration of approved plant-specific probabilistic risk assessments (PRAs), regulatory issues, or other design considerations.

(b) Determine the specific test requirements of Divisions 1 through 3 of ASME OM for each component and system identified per (a) above.

(c) Review the system design and the component specifications for testability for each test identified in (b) above and provide design features to support the required testing. Not all requirements will apply to each component or system situation. Considerations include

(1) the capability to perform full-flow testing of the system or pump

(2) the capability to perform required testing during any plant operating mode, including normal operation

(3) minimizing impact on plant safety and risk

(4) minimizing Technical Specification Action Statement entries

(5) minimizing safety-system availability impact

(6) minimizing temporary plant alterations to perform required testing

(7) the capability to perform required leakage testing (e.g., valve, system, containment building, etc.)

(8) the required test-instrumentation accuracy

(9) instrumentation, component, and system accessibility for plant personnel, including dose and safety considerations

(10) the capability for test-data collection via inputs to the plant computer (e.g., pump pressure and flow data vs. time; valve position vs. time data)

[1] As accepted in Revision 3 to NRC Regulatory Guide (RG) 1.100.

(11) installing dedicated containment electrical penetrations for use by startup instrumentation, including provision for separate power and control penetrations

(12) minimizing the need for relief from the testing requirements of ASME OM, Division 1

(13) accommodating the application of software-based digital technology for pumps and valves

(14) assessing the potential adverse effects on pumps and valves from flow-induced vibration caused by hydrodynamic loads and acoustic resonance, by evaluating potential vibration levels as part of the design process, establishing vibration acceptance criteria, and monitoring vibration levels and performing walkdown assessments during preservice and inservice testing

(15) coordinating preservice testing and inspections, tests, analyses, and acceptance criteria (ITAAC) activities during the design process, where applicable

(16) the proper maintenance of inservice testing components and personnel training during the design process, and their relationship to preservice and inservice testing requirements

(d) Document the actions taken and the associated bases to address (a) through (c) above in an appropriate manner that supports historical understanding of the bases for the design decisions.

M-3200 Subsection ISTF (Pumps)[2]

Subsection ISTF requires that pumps be tested periodically and performance data collected such that deviation from predetermined reference values can be determined and evaluated. Consider the following information to support Subsection ISTF testing and to minimize the plant impact from periodic testing. Some features are to be considered within the design of the connected piping system, while others are required information or features within the pump specification.

M-3210 Flow. Provide a broad flow range, including full flow, considering the following:

(a) Design the piping network to draw from an available source and return. Ensure that the entire testing flow path contains adequate vent valve locations to address potential gas accumulation. This is a system requirement.

(b) Design the piping path for use during normal power operation. This is a system requirement.

(c) Design throttling capability for the full range of required pump operation, from minimum flow to maximum required design-basis flow. Select valves with throttling resolution compatible with design test conditions. Ensure that protection is provided to prevent pump runout. Evaluate the benefit of using normal system piping or dedicated test piping (or a combination) to ensure the flow testing range is accommodated.

(d) Design the systems for implementation of the comprehensive pump-testing provisions of ASME OM, Division 1 without the need for regulatory relief.

(e) Design the test flow path to support the testing duration without pump heat raising fluid temperature above acceptable limits. If the test flow path will not have adequate cooling, describe this limitation in the pump purchase specification or consider an alternate recirculation-path heat exchanger with the capability for heat-removal cooling during power operation.

(f) Document expected test durations and performance parameters in the pump design specification.

(g) Design the flow path for the tested pump such that the operability of other pumps is not impacted during the test. Ensure that the discharge of the tested pumps is designed to avoid adverse interaction with other systems (e.g., shared miniflow, causing inoperability of an alternate train).

M-3220 Test Data Collection. Consider the following when data collection is required:

(a) Provide permanently installed instrumentation that will meet or exceed Subsection ISTF measurement-accuracy requirements to support data collection.

(1) Provide direct-flow measurement capability in the discharge piping of each individual pump, for each pump requiring Subsection ISTF testing.

(-a) Avoid reliance on a single wide-range instrument located in a common pump-discharge header. For example, provide a flow orifice with permanent differential pressure instrumentation.

(-b) Provide a suitable piping arrangement to assure accurate flow measurement.

(-c) Consider recommended location limitations as prescribed within a standards document such as ISO 5167:2003.

(2) Provide pump-discharge and suction pressure-measurement instrumentation in close proximity to the pump for measuring differential pressure for each pump requiring Subsection ISTF testing. Locate pressure taps in the piping configuration per the instrument manufacturer's recommendations or suitable industry standards such as those published by American National Standards Institute/Hydraulic Institute (ANSI/HI) or by ASME in the Performance Test Codes.

(3) Provide for vibration and speed measurement for each pump requiring Subsection ISTF testing. In addition, consider permanently installing accelerometers on shaft bearings to monitor vibration on deep draft pumps.

(4) Allow for in situ calibration, or accommodate easy removal to a calibration/instrument maintenance shop.

[2] Subsection ISTF applies to nuclear power plants with a construction permit or combined license issued on or after January 1, 2000; Subsection ISTB applies to nuclear power plants with a construction permit issued prior to January 1, 2000.

(5) Consider instrument fluctuations and readability to ensure test repeatability (i.e., readability for establishing reference values).

(b) Describe in the pump specification document explicit locations for the instruments and accuracy of this instrumentation when the instrumentation is to be supplied by the pump vendor.

M-3300 Subsection ISTC (Valves)

Subsection ISTC requires that valves be tested periodically and performance data collected to ensure that the valves are performing within specified acceptance limits.

Based on the required function(s), provide for the following types of testing in the plant design.

M-3310 Leak-Rate Testing of Subsection ISTC, Category A Valves

(a) Design system configurations to support leak-rate testing as follows:

(1) Provide upstream and downstream isolation capability such that the test volume can be pressurized with the appropriate medium to the required test pressure. For example, for containment isolation valves (CIVs) that may come in direct contact with the primary containment atmosphere following an accident, provide the capability to perform leak-rate testing using air or other pneumatic media at a pressure equal to the maximum postaccident containment pressure.

(2) Provide test connections upstream and downstream of the Category A valves for pressurization and venting to ensure that the required pressure differential is achieved and that the Category A valves can be tested in the accident mitigation direction.

(3) Provide capability to test valves during normal plant operation where practical.

(4) Locate valves to be accessible during normal plant operation.

(5) Provide a test configuration that will not affect the operability or availability of redundant systems during the test duration.

(6) Provide the capability to isolate individual valves to support testing and facilitate diagnosis or repair for system configurations with parallel isolation valves.

(7) Provide capability to perform leak-rate testing using the service medium for the system at a pressure equal to the maximum pressure to which the valve will be exposed during the specific function for which it is designed.

(b) Design test-data collection capability as follows:

(1) Provide suitable provisions to connect temporary pressure-measurement instrumentation that will meet Subsection ISTC measurement accuracy requirements for the test connections described in (a)(2) above.

(2) Provide suitable arrangement for measurement of leakage flow, pressure feed rate, or pressure decay versus time. Provide means to contain leakage inventory or have suitable drain capability for leakage-flow measurement.

(3) Provide permanently installed instrumentation that will meet or exceed Subsection ISTC measurement accuracy requirements for locations where local access may not be possible during required testing.

M-3320 Exercise Testing of Subsection ISTC, Category A and Category B Valves. Design system configurations to support exercise testing as follows:

(a) Provide system configuration such that the system is not adversely impacted by stroking the valve (i.e., it does not cause loss of system keep-fill function).

(b) Provide system configuration such that the operability or availability of redundant valves or systems are not impacted during the stroke test.

M-3330 Exercise Testing of Subsection ISTC, Category C Valves

(a) Design system configurations to support exercise testing as follows:

(1) Provide test connections upstream of the check valve to allow reverse-flow testing.

(2) Provide test connections as required to facilitate makeup or motive flow for forward- and reverse-flow testing.

(3) Provide testable check valves where required forward- or reverse-flow testing cannot be performed.

(b) Design test-data collection capability to support exercise testing as follows:

(1) Provide instrumentation to verify that forward-flow criteria are met for check valves.

(2) Provide instrumentation upstream of the check valve to facilitate reverse-flow testing.

(3) Refer to subpara. M-3310(b) for further instrumentation guidance.

M-3340 Exercise Testing of Subsection ISTC, Category D Valves

(a) Design system configurations to support ISTC requirements as follows:

(1) Provide unobstructed local visual access to nonreclosing pressure relief devices.

(2) Provide unobstructed local access to the charge on pyrotechnic-actuated (squib) valves.

(b) Include provisions in squib valve designs for the capability to perform, with sufficient access, inservice testing and inspection activities to assess the integrity of internal parts and the presence of fluid or foreign material that might adversely impact the performance or integrity of the squib valve and its actuator.

M-3350 Position-Indication Verification Testing of Subsection ISTC Valves

(a) Provide unobstructed local visual access for valve-position confirmation for valves with remote position indication.

(b) For valves that cannot be observed directly, such as solenoid valves, specify instrumentation that can be used to confirm actual valve position.

M-3360 Valve Specifications or Plant Design. Consider the following provisions in the valve specification or plant design as appropriate:

(a) Design test-data collection capability to support diagnostic testing of motor-operated valves (MOVs), air-operated valves (AOVs), and hydraulic-operated valves (HOVs) as follows:

(1) Provide inputs to the plant computer to allow collection of sufficient diagnostic data of performance parameters for power-operated valves to ensure proper setup and performance evaluation per Subsection ISTC requirements.

(2) Refer to subpara. M-3310(b) for further instrumentation guidance.

(b) Diagnostic Testing of Motor-Operated Valves (MOVs)

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., stem strain gages, smart-valve technology). Include quick-disconnect capability for diagnostic equipment to the valve motor and internal torque and limit switches.

(2) Specify that the valve design provides for monitoring potential rotor degradation, where applicable (such as in magnesium rotors).

(3) Ensure the system design allows for the periodic verification of MOV design-basis capability during preservice and inservice testing. Design the system to allow MOV testing at design conditions (e.g., full-flow and design temperature and pressure). This includes considerations set forth in ASME OM, Division 1, Appendix III that mandate that a program be established to ensure that MOVs continue to be capable of performing their design-basis safety functions.

(4) Provide ready access at motor-control centers to allow diagnostic testing of MOVs.

(5) Specify MOV orientation and location during the design process to ensure consideration of the potential impact on access for IST activities and maintenance.

(c) Diagnostic Testing of Air-Operated Valves (AOVs)

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., smart-valve technology).

(2) Consider guidance provided for AOVs by ASME OM, Division 3, Part 19.

(3) Ensure the system design allows for the periodic verification of AOV design-basis capability during preservice and inservice testing. Design the system to allow AOV testing at design conditions (e.g., full-flow and design temperature and pressure).

(4) Ensure the system and valve design applies the lessons learned from MOV-operating experience and performance testing to facilitate testing of AOVs.

(d) Diagnostic Testing of Hydraulic-Operated Valves (HOVs)

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., smart-valve technology).

(2) Consider guidance provided for HOVs by ASME OM, Division 3, Part 19.

(3) Ensure the system design allows for the periodic verification of HOV design-basis capability during preservice and inservice testing. Design the system to allow HOV testing at design conditions (e.g., full-flow and design temperature and pressure).

(4) Ensure the system and valve design applies the lessons learned from MOV-operating experience and performance testing to facilitate testing of HOVs.

(e) Check Valve Testing

(1) Consider specification of external disk movement devices.

(2) Consider specification of built-in, or the ability to accept, monitoring and diagnostic equipment.

(f) Safety/Relief Valve Testing

(1) Provide local access for removal and reinstallation of relief valves to accommodate remote testing.

(2) Provide isolation for relief valves to minimize system draindown and refill impact due to valve removal, while maintaining compliance with applicable design Codes.

(g) Manual Valve Testing. Specify hand-wheel capability with appropriate extension shafts for local unobstructed access to valves during normal operation. Provide access for the operation, periodic testing, and inspection of manual valves to ensure their capability to perform any applicable safety functions at design-basis system and environmental conditions.

M-3400 Subsection ISTD (Snubbers)

(a) Select the location along the pipe to minimize interference with local structures, components, and adjacent piping.

(b) Provide local access to snubbers for visual inspection and for removal for testing and reinstallation.

(c) Provide rigging support locations for snubber removal and replacement.

(d) Consider the impact on system availability if a snubber is temporarily removed for testing.

(e) Minimize the impact of removing a single snubber on alternate system or component trains or divisions.

(f) Consider specifying snubbers with built-in, or with the ability to accept, diagnostic equipment (e.g., load pin and displacement transducers) where appropriate based upon size, ease of removal, location access, and operational impact of removal.

M-3500 Other Considerations

The following are considerations for the design organization to accommodate testing of certain non-Code components and monitoring systems.

M-3510 Division 2, Part 21 (Inservice Performance Testing of Heat Exchangers), and Division 3, Part 11 (Vibration Testing and Assessment of Heat Exchangers)

(a) Evaluate the need for future testing per the requirements of ASME OM, Division 2, Part 21, and Division 3, Part 11.

(b) Design installed instrumentation accordingly with consideration of associated accuracy. Pay particular attention to temperature measurement on primary and secondary sides, considering instrumentation location and accuracy due to the sensitivity of these data in the performance evaluation.

(c) Provide suitable access for internal visual inspection. Consider this information in preparation of the component's specification.

(d) Provide suitable access and clearance area to permit disassembly (i.e., bundle removal).

M-3520 Division 2, Part 12 (Loose Part Monitoring). Consider guidance provided by ASME OM, Division 2, Part 12 for the design of loose part monitoring systems.

M-3530 Division 2, Part 24 (Reactor Coolant Pumps and Recirculation Pumps). Consider guidance provided by ASME OM, Division 2, Part 24 for the design of pump-monitoring systems.

M-3540 Division 3, Part 14 (Vibration Monitoring of Rotating Equipment). Consider specification of installed vibration-monitoring capability as recommended by ASME OM, Division 3, Part 14.

M-3550 Division 2, Part 16 (Standby Diesel Generator Systems)

(a) Review ASME OM, Division 2, Part 16 for diesel testing recommendations and consider appropriate features in the design specification.

(b) Consider specification of diesel and generator components and subcomponents with built-in, or with the ability to accept, diagnostic and monitoring equipment.

(1) Consider adding provisions for monitoring and diagnostics of the mechanical equipment (e.g., taps for pressure gages, or recorders or transmitters).

(2) Consider adding provisions for monitoring and diagnostics of the electrical equipment (e.g., voltages, high-speed recorders for signal capture).

(c) Consider provisions of permanently installed instrumentation that will meet or exceed measurement accuracy requirements to support data collection described in Part 16.

(d) For subcomponents within the scope of ISTC and ISTF, refer to paras. M-3200 and M-3300, respectively, for additional guidance.

M-3560 Division 2, Part 3 (Vibration Testing of Piping Systems), and Division 3, Part 7 (Thermal Expansion Testing)

(a) Consider specification of installed capability for monitoring vibration and thermal expansion as recommended by ASME OM, Division 2, Part 3, and Division 3, Part 7.

(b) Consider inclusion of piping pressure taps for installation of dynamic pressure transducers during startup testing.

(c) Consider including load cell installation on snubbers.

(d) Consider accommodations for installation of test instrumentation (e.g., accelerometers or displacement indicators) at locations throughout the plant, and associated instrumentation brackets. Consider the use of wireless technology to minimize cable routing.

(e) Consider installing dedicated containment electrical penetrations for use by startup instrumentation, including provision for separate power and control penetrations.

(f) Nuclear power plant operating experience reveals the importance of maintaining vibration of plant components within acceptable limits. When considering the above guidance for vibration testing, ensure that the plant design facilitates monitoring the dynamic effects of steady-state flow-induced vibration and anticipated operational transient conditions on critical system components.

M-3570 Division 3, Part 19 (Pneumatically and Hydraulically Operated Valves). Consider guidance provided by ASME OM, Division 3, Part 19 in addition to subparas. M-3360(b)(1) and M-3360(c)(1).

M-3600 Division 2, Part 28 (System Testing Capability)

ASME OM, Division 2, Part 28 provides a robust roadmap for system testing. A detailed review of that Part reveals the following considerations for the plant design organization:

(a) Capture and thoroughly document the design basis for plant systems to ensure that system performance requirements are understood by the plant owner.

(b) Provide the capability for online multipoint pump-performance testing, for systems with variable flow requirements.

(c) Provide pressure measurement capability at locations in the tested system to the extent of data location necessary to support discharge-path flow resistance.

(d) Establish the data measurement requirements, considering instrumentation location and accuracy due to the sensitivity of these data in the evaluation of performance test results. Provide suitable instrumentation hardware commensurate with the testing frequency (i.e., installed hardware to support frequent testing, temporary hardware for infrequent testing).

(e) Provide system alignment capability that maximizes simultaneous or integrated testing.

(f) Provide system alignment capability that will allow single-train testing without impact on other trains.

(g) Provide flow measurement for minimum recirculation flow path.

M-4000 REFERENCES

ASME QME-1–2007, Qualification of Active Mechanical Equipment Used in Nuclear Power Plants

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ISO 5167:2003, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full

Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

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DIVISION 2: OM STANDARDS

CONTENTS

Part 2
Performance Testing of Closed Cooling Water Systems in Light-Water Reactor Power Plants

Superseded by Part 28.

Part 3
Vibration Testing of Piping Systems

1 SCOPE

This Part establishes vibration testing requirements for certain piping systems in light-water reactor (LWR) power plants. This Part is applicable to preservice and initial startup testing, and plant post modification testing (e.g., power uprate and steam generator replacement). This Part may be used to assess vibration levels of applicable piping system during plant operation. This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

ASME B31: ASME Code for Pressure Piping.

ASME BPV Code: ASME Boiler and Pressure Vessel Code.

Design Specification: the document provided by the Owner, as required by NCA-3250 or NA-3250 of the ASME BPV Code, Section III, for the component/system, which contains requirements to provide a complete basis for the construction of the component/system.

design verification: the process of reviewing, confirming, or substantiating a design by one or more methods to provide assurance that the design meets the specified design input.

duplicate: a system built on the basis of a previously used and proven design for which test results are available.

hot shimming: the process of adjusting support and restraint clearances in the hot condition.

initial start-up testing: test activity performed during or following initial fuel loading, but prior to commercial operation. These activities include fuel loading, precritical tests, initial criticality tests, low power tests, and power ascension tests.

maintenance/repair/replacement: actions taken to prevent or correct deficiencies in the system operation.

normal operating conditions: the service conditions the system would experience when performing its intended function.

operational testing: test activities performed subsequent to initial start-up testing (e.g., testing performed during commercial operation of the plant).

Owner: the organization legally responsible for constructing and/or operating a nuclear facility including, but not limited to, one who has applied for or who has been granted a construction permit or operating license by the regulatory authority having lawful jurisdiction.

peripheral equipment: device(s) used in the setup, checkout, or on-site calibration of other VMS devices.

physical units: the engineering units that quantitatively represent the measured variable (e.g., if the measured variable is displacement, the physical units can be inches, mils, feet, or meters).

preoperational testing: test activities performed prior to initial fuel loading.

processing equipment: device(s) used for further handling, reformatting, or manipulation of the transducer output to reduce it to manageable or intelligible information.

prototype: system built on the basis of an original design for which there are no previous system test results available.

quality assurance: all those planned and systematic actions necessary to provide adequate confidence that an item or facility will perform satisfactorily in service.

record drawing set: the set of drawings that defines the system's layout and support configuration at the time the system is placed in service for testing.

recording and display equipment: recording equipment devices are used for storing signals in a form capable of subsequent reproduction. Display equipment devices are used to obtain a visual representation of a signal (conditioned and/or processed transducer output).

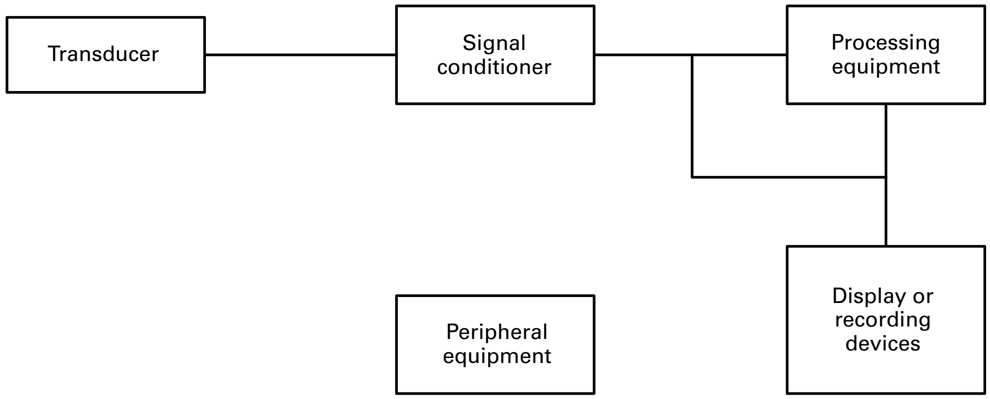
shell-wall vibration: radial vibration of a pipe wall, which typically occurs at high frequencies, characterized by axial and circumferential lobate mode shapes and natural frequencies.

signal conditioner: device(s) used to modify or reformat the transducer output to make it intelligible to or compatible with processing equipment.

steady-state vibrations: repetitive vibrations that occur for relatively long periods of time during normal plant operation.

system: an assembly of piping subassemblies and components whose limits and functions are defined in its Design Specification.

Fig. 1 Typical Components of a Vibration Monitoring System (VMS)



system interconnections: all cables, wires, or mechanical linkages used between the devices comprising the VMS.

system specification: that document that uniquely describes the VMS. The system specification shall contain the information specified in para. 7.2.

test conditions: the conditions experienced by the system when undergoing tests.

test hold points: events in the test program usually associated with system operating conditions for which test information is to be collected (e.g., with the reactor at X% power and with the system at full flow).

test specification: the document(s) prepared by the Owner or his assignee that meet(s) the requirements set forth in section 3 of this Part.

transducer: a device that converts shock or vibratory motion into an optical, mechanical, or, typically, an electrical signal that is proportional to a parameter of the experienced motion.

transient vibrations: vibrations that occur during relatively short periods of time and result in less than 10^6 stress cycles. Examples of transient sources of vibration are pump actuation and pump switching, rapid valve opening or closing, and safety relief valve operation.

vibration monitoring system (VMS): the system composed of all instrumentation or test equipment used to measure and record the vibration data. It is assumed to have as input the monitored variable (i.e., displacement velocity and acceleration) at the measurement location. The system output is a signal analogous to the measured variable and readily convertible to appropriate physical units. A typical VMS is shown in Fig. 1.

3 GENERAL REQUIREMENTS

The Owner shall determine the portions of piping systems to be tested and shall classify these systems into the vibration monitoring groups defined below. The minimum general requirements for the classification by groups are provided in para. 3.1; however, the Owner may place a system into a more stringent vibration monitoring group (VMG).

Vibration conditions are classified into steady-state and transient vibration categories. A system may be classified into one vibration monitoring group for steady-state vibrations and into another group for transient vibrations. The testing requirements, acceptance criteria, and recommendations for corrective action associated with these categories are provided below. The vibration testing and assessment of vibration levels may be conducted during preoperational and initial start-up testing or during plant operation in accordance with the requirements of the test specification.

For preoperational, initial start-up, and operational testing, a test specification shall be prepared that will include, as a minimum, the following items:

(a) test objectives

(b) systems to be tested (including boundaries)

(c) pretest requirements or conditions

(d) governing documents and drawings

(e) precautions

(f) quality control and assurance (including required documentation and sign-offs)

(g) acceptance criteria

(h) test conditions and hold points

(i) measurements to be made and acceptable limits (including visual observations)

(j) instrumentation to be used (including instrument specifications)

(k) data handling and storage

(l) system restoration

The test specifications shall be written in a manner to ensure that the objectives of the tests are satisfied and that results obtained are accurate or conservative. Prior to testing, an inspection of components and supports shall be made to verify correct installation according to the record drawing set, specifications, and appropriate codes.

When test results are to be correlated to specific analysis, test conditions and measurements should be sufficiently specified to ensure that the parameters and assumptions used in the analysis are not violated. The correlation between test and analysis should confirm the validity of the analysis and should indicate that the analytical results are conservative. If the test results indicate that the analysis is not adequate or when the measured data from the test indicates that the actual forcing function is not conservatively covered by the forcing functions used in the analysis, the analysis should be reconciled.

The vibration monitoring requirements and acceptance criteria are defined in para. 3.2. If the test data exceeds the value specified in the hold point section of the test specification, two options are available: further testing or evaluation to a more rigorous method or corrective action taken, as described in section 8.

Cognizant engineering personnel shall participate in the development of test specification requirements, selection of instrumentation, establishment of acceptance criteria, review, evaluation, and approval of test results.

Selection of the locations of measuring devices and the type of measurements to be made shall be based on piping stress analysis, response of a similar system, or experience gained through testing of the subject system and shall reflect any unique operational characteristics of the system being tested. Evaluation of the test data shall consider characteristics of the measuring devices used.

3.1 Classification

Piping system vibrations are classified into two categories, steady-state and transient, as defined in section 2. Within each applicable category, the piping system shall be classified into one of the three vibration monitoring groups according to the criteria presented in paras. 3.1.1 and 3.1.2.

Piping systems that are inaccessible for visual observation or measurement using portable devices, as a result of adverse environmental effects during the conditions listed in the test specification, shall be classified into either VMG 1 or VMG 2.

In addition to the requirements presented in paras. 3.1.1 and 3.1.2, the safety or the power generation function, or both, of the system should also be considered when classifying the system into the vibration monitoring groups.

3.1.1 Steady-State Vibration

3.1.1.1 Vibration Monitoring Group 1. The monitoring program required for systems evaluated in this group typically involves sophisticated monitoring devices and extensive data collection to accurately determine vibratory pipe stresses or other specified component limitations.

Determination of mode shapes, modal response magnitudes, and total system response is possible using these evaluation techniques. When accurate measurement of the system response characteristics is required, the techniques and devices implied by the requirements for this vibration monitoring group shall be employed.

All portions of piping systems that experience steady-state vibrations and meet one of the following requirements shall be classified in VMG 1 and shall meet the acceptance criteria of para. 3.2.1:

(a) piping systems that exhibit a response not characterized by simple piping modes (e.g., piping shell-wall vibrations, as defined in section 2)

(b) piping systems for which the methods of VMG 2 and VMG 3 are not applicable based on limitations given in sections 4 and 5

3.1.1.2 Vibration Monitoring Group 2. The methods and devices employed in the evaluation of VMG 2 provide a means of measuring and assessing the piping vibration at a given location.

All portions of piping systems that meet one of the following requirements shall be classified in VMG 2 and shall meet the acceptance criteria specified in para. 3.2.2:

(a) all piping systems that may exhibit significant vibration response based on past experience with similar systems or similar system operating conditions

(b) piping systems for which the method of VMG 3 is not applicable

3.1.1.3 Vibration Monitoring Group 3. The visual method employed in the evaluation of VMG 3 is most fundamental and provides the most simplified means for determining whether any significant vibrations exist in the system. Evaluation of vibration levels using this method is based on experience and judgment and provides an acceptable basis for assessment. If firm quantitative assessments are required, the methods in VMG 1 or VMG 2 should be employed.

All portions of piping systems that meet one of the following requirements shall be classified in VMG 3 and shall meet the acceptance criteria specified in para. 3.2.3:

(a) systems falling in VMG 1 or VMG 2 classification for which measurements or prior test data are available on prototype or duplicate systems and for which the minimum unacceptable vibrations are observable

(b) portions of ASME Classes 1, 2, 3, and ASME B31 piping systems that are not expected to exhibit significant vibrational response based on past experience with similar systems or system operating conditions

3.1.2 Transient Vibration. Table 1 presents some examples of transient conditions to which systems may be subjected.

3.1.2.1 Vibration Monitoring Group 1. Portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in

Table 1 System Tolerances

System Design Parameters	Allowable Tolerance Range	Units	
		Customary	SI
System flow [Note (1)]	+10%	gpm	m^3/s
Head [Note (2)]	+10%	psi	kPa
Thermal capacity Q [Note (3)]	−10%	Btu/hr	Cal/h
Overall heat transfer coefficient [Note (4)]	−10%	Btu/hr-ft²-°F	Cal/h-cm²-°C

NOTES:
(1) The upper limit of flow is that which will not produce unacceptable vibration in the heat exchangers in any system flow mode.
(2) The upper limit of head is determined by limiting pressure drop across heat exchanger in any flow mode.
(3) $Q = UA\Delta T$, where U = overall heat transfer coefficient; A = surface area of heat exchanger, ft^2 (cm^2); and ΔT = log mean temperature difference, °F (°C).
(4) The lower U limit is indicative that surface fouling may cause unacceptable thermal capacity in the future.

VMG 1 and shall meet acceptance criteria specified in para. 3.2.1. Systems from past plant operation experience are known to experience significant dynamic transient conditions due to the inherent nature of component design, system operation, or system design features, for which a transient analysis is not performed.

3.1.2.2 Vibration Monitoring Group 2. Portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in VMG 2 and shall meet acceptance criteria specified in para. 3.2.2. Systems are designed and analyzed for known anticipated dynamic loading conditions and for the applied loading (i.e., fluid or mechanical), which is based on methodology that is known to conservatively predict the transient forcing function and corresponding structural response.

3.1.2.3 Vibration Monitoring Group 3. All portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in VMG 3 and shall meet the acceptance criteria specified in para. 3.2.3. Systems that undergo transient vibrations during their operating life (e.g., systems subjected to pump start-up transients, valve opening, or closure) and that by past experience with similar systems or system operating conditions are not expected to exhibit significant vibrational response.

3.2 Monitoring Requirements and Acceptance Criteria

Special attention should be given to the precautions listed in para. 4.3.

The acceptance criteria presented in this paragraph are based on the following list of assumptions. The Owner may invoke less stringent criteria provided sufficient justification is given. More stringent criteria shall be invoked if these assumptions are deemed inappropriate for the system under review.

(a) Vibrations cause maximum stresses within the elastic range; therefore, no penalty for plastic cycling is incurred.

(b) Thermal transient effects, if they exist during the vibration incident, have already been considered in the piping system evaluation.

(c) The membrane stresses caused by pressure fluctuations alone are insignificant in comparison to the stresses caused by the vibratory moments.

(d) The usage factor from the vibration incident does not significantly affect the cumulative usage factor calculated for other predefined transient conditions.

(e) Strain-controlled fatigue curves of the BPV Code, Section III represent the S-N fatigue characteristics for the material and loading considered.

3.2.1 Vibration Monitoring Group 1

3.2.1.1 The vibration response of Group 1 systems shall be evaluated using the methods and devices listed in section 6 of this Part.

3.2.1.2 For steady-state vibration, the maximum calculated alternating stress intensity, S_{alt}, should be limited as defined below.

(a) For ASME Class 1 piping systems

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq \frac{S_{el}}{\alpha}$$

where

C_2 = secondary stress index as defined in ASME BPV Code, Section III

K_2 = local stress index as defined in ASME BPV Code, Section III

M = maximum zero to peak dynamic moment loading due to vibration only, or in combination with other loads, as required by the system Design Specification

S_{el} = 0.8 S_a, where S_a is the alternating stress at 10^6 cycles in psi (MPa) from ASME BPV Code, Section III, Fig. I-9.1; or S_a at 10^{11} cycles from ASME BPV Code, Section III, Fig. I-9.2.2. The user shall consider the influence of temperature on the modulus of elasticity.

Z = section modulus of the pipe

α = allowable stress reduction factor: 1.3 for materials covered by ASME BPV Code, Section III, Fig. I-9.1; or 1.0 for materials covered by ASME BPV Code, Section III, Fig. I-9.2.1 or I-9.2.2

(b) For ASME Classes 2 and 3 piping and ASME B31

$$S_{alt} = \frac{C_2K_2}{Z} M \leq \frac{S_{el}}{\alpha}$$

where

C_2K_2 = $2i$

i = stress intensification factor, as defined in ASME BPV Code, Section III, Subsections NC and ND or ASME B31

If significant vibration levels are detected during the test program that have not been previously considered in the piping system analysis, consideration should be given to modifying the Design Specification to reverify applicable code conformance.

3.2.1.3 For transient vibrations, the maximum alternating stress intensity should be limited to the value defined below. Before determining the allowable maximum alternating stress intensity, an estimate should be made of the equivalent number of maximum anticipated vibratory load cycles (n).

(a) For ASME Class 1 piping systems, the maximum alternating stress intensity shall be limited to the value that will not invalidate the design basis. If the transient event was not previously considered in the design basis, the event shall be evaluated. The unused usage factor shall be determined from

$$U_v = 1 - U$$

where

U = cumulative usage factor from ASME Class 1 analysis, which excluded vibratory load

The maximum allowable equivalent vibratory load cycles shall be calculated from

$$N_v = \frac{n}{U_v}$$

Using N_v, the maximum alternating stress intensity S_{alt} shall be limited to S_a where

S_a = allowable alternating peak stress value from ASME BPV Code, Section III, Fig. I-9.1, I-9.2.1, or I-9.2.2.

For transient vibrations that were not previously analyzed and for which it is not appropriate to evaluate the load separately, a new fatigue analysis may be required in accordance with Section III of the ASME BPV Code.

(b) For ASME Classes 2 and 3 and ASME B31 piping, the stresses shall be evaluated in accordance with the requirements of subpara. 3.2.1.2(b). Alternatively, the appropriate ASME code shall be used to evaluate the stresses for transient vibration.

3.2.2 Vibration Monitoring Group 2

3.2.2.1 The vibration response of Group 2 systems should be measured using one or more of the vibration monitoring devices specified in section 5.

3.2.2.2 For steady-state vibration, the piping vibratory responses of VMG 2 piping shall be evaluated in accordance with the allowable deflection or velocity limits given in section 5. These limits are based on meeting the stress requirements of para. 3.2.1. If adequate quantitative data cannot be obtained or unacceptable vibration response is indicated by the methods and devices listed in section 5, the methods and devices of section 6 may be used.

3.2.2.3 For transient vibration, the criteria of para. 3.2.2.2 for steady-state vibration may be used as a screening tool but may be overly conservative. If these limits are exceeded, the criteria of para. 5.2.3 or the criteria of para. 3.2.1.3 shall be employed.

3.2.3 Vibration Monitoring Group 3

3.2.3.1 The vibration response of Group 3 systems shall be determined by the methods and devices listed in section 4.

3.2.3.2 If an acceptable level of steady-state or transient vibration is noted, no further measurement or evaluation is required. The observer shall be responsible for assessing whether the observed vibration level is acceptable. The basis for determining whether the vibration level is acceptable shall be consistent with the limits specified in para. 3.2.1.

3.2.3.3 If the level of vibration is too small to be perceived and the possibility of damage is judged to be minimal, the system is acceptable.

The judgment as to acceptability can be made only by the evaluation of all the following facts as to their effects on the piping stress:

(a) vibration magnitude and location

(b) proximity to "sensitive equipment"

(c) branch connection behavior

(d) capability of nearby component supports

Any unique operational characteristics of the system shall be considered in the evaluation.

3.2.3.4 If an acceptable assessment of the observed deflections cannot be made, the acceptability of vibration must be based on measured data.

3.2.3.5 If unacceptable vibration levels are indicated by the methods and devices listed in section 4, the methods and devices of section 5 may be used.

3.2.4 Qualitative Evaluations. Piping system response must be acceptable based on qualitative evaluations, in addition to meeting the quantitative acceptance criteria defined in para. 3.2. Qualitative evaluations are based on observed response of the piping that address potentially detrimental conditions not explicitly quantified by the acceptance criteria of para. 3.2. Judgments on the acceptability of the observed responses shall be based on comparisons to known acceptable responses. Nonmandatory Appendices G and H provide additional guidance on the use of qualitative evaluations.

4 VISUAL INSPECTION METHOD

4.1 Objective

The acceptability of piping systems in VMG 3 to withstand the effects of steady-state and transient vibrations can be evaluated by observation. Different techniques and simple devices that can be employed in the evaluation as well as some of the possible problems that could be encountered during the preoperational phase and startup of systems are described below.

4.2 Evaluation Techniques

The location or locations of maximum deflection can be ascertained by observation. The magnitude of the displacement may be estimated by the use of simple measurement devices (e.g., rules, optical wedge, and spring hanger scale). When simple measurement devices are used, the precautions of Nonmandatory Appendix A shall be observed. As an aid in developing judgment of the acceptability of observed displacements, simple beam analogies may be used.

4.2.1 Steady-State Vibration. During the preoperational and start-up testing phases of a plant, the piping systems shall be observed during their various modes of operation, as defined in the test specification. The acceptability of the observed vibration shall be determined in accordance with para. 3.2.3.

4.2.2 Transient Vibration. During the preoperational and start-up testing phases of a plant, the piping systems in VMG 3 shall be observed during the transient events as defined in the test specification. The test may be repeated, if necessary, to make the observations at different points. The acceptability of the observed response shall be based on para. 3.2.3.

4.3 Precautions

Below are a few precautions and specific items that should be reviewed.

4.3.1 Vents and Drains. Local vents and drains typically have one or two isolation valves that act as concentrated masses. If they have not been braced, careful attention should be given to vibration in this area.

4.3.2 Branch Piping. Minor mainline vibration may cause branch piping vibration of significant magnitude remote from the branch connection. These lines shall be reviewed together with the system being qualified.

4.3.3 Multiple Pump Operation. In cases where there are several pumps that operate in parallel, the most significant vibration will occur when some combinations of the pumps are operating. These combinations shall be reviewed together with the system being qualified.

4.3.4 Sensitive Equipment. Vibrations that can affect the functionality, operability, and structural capability of sensitive equipment, such as pumps, valves, and heat exchangers, should be closely reviewed.

4.3.5 Welded Attachment. Special consideration shall be given to the areas near the welded attachment in the piping system subjected to vibration. If the welded attachment configuration is such that it could cause local moments in the pipe due to vibration, the effects of local stress should be considered.

5 SIMPLIFIED METHOD FOR QUALIFYING PIPING SYSTEMS

5.1 Steady-State Vibration

There are simplified methods for the evaluation of steady-state vibration of piping systems that will determine if the vibration exceeds an acceptable level. These methods apply to systems that are undergoing steady-state vibration and are accessible for a number of vibration measurements at various points in the piping system. Piping systems that are not suitable or adaptable to these methods may be evaluated by procedures defined in section 6.

5.1.1 Displacement Method

5.1.1.1 General Requirements. The simplified method requires that vibratory displacement should be determined at representative points on the piping system. The piping system shall be subdivided into sufficient subsystems or vibratory characteristic spans containing appropriate or conservative boundary conditions as described in detail in subpara. 5.1.1.6(a).

5.1.1.2 Instrumentation. A handheld or temporarily mounted transducer that is suitable for making multiple measurements of displacement should be used. For example, an accelerometer may be used with velocity and displacement of the acceleration signal obtained by single and double integration, respectively. The precautions on measurement techniques should be observed (section 7). It is recommended that response frequencies and their relative amplitudes be determined as an aid in verifying the appropriateness of the characteristic span model selected and to assist in determining the source of vibration.

5.1.1.3 Deflection Measurement of Process Piping. Measurements are taken along the piping to measure peak deflection points and to establish node points of minimum deflection. The node points establish the characteristic span lengths. Node points (zero deflection points) are generally found at restraint points, but could be located between constraints on long runs of piping. The deflection limit can be determined from the information presented in Figs. 2 through 9.

5.1.1.4 Deflection Measurement of Branch Piping. Branch piping is attached to process piping and has a smaller diameter than the process piping. Three of the potential problems that can exist are described below.

(a) Branch piping can be excited at or near its resonant frequency by motion of the process piping, fluid pulsation, or other sources. This problem is characterized by high amplitude vibrations with a clearly defined frequency and mode shape. The amplitude measured on the branch pipe is generally much larger than the process piping. Due to the phasing, the relative motion of the branch pipe to the process pipe is closely approximated by adding the displacement measurement of the process pipe to the motion of the branch pipe. The deflection limits defined in para. 5.1.1.5 are applicable.

(b) The attachment point of the branch pipe with the process line displaces relative to a branch line support. The deflection limits defined in para. 5.1.1.5 are applicable when the deflections measured reflect relative motion between points on the branch piping and can be associated with a deflected shape.

(c) The process piping drives the branch piping at a high acceleration level as a rigid body. This problem is generally associated with a cantilevered mass. The peak acceleration at the center of gravity of the branch piping must be measured to establish the inertial force acting at the center of gravity of the branch piping. The cantilever mass and center of gravity of the branch piping must be conservatively estimated and a resultant stress calculated. The resultant stress should be compared with the criteria listed in subparas. 3.2.1.2(a) and 3.2.1.2(b).

Nonmandatory Appendix I provides guidance on completing this evaluation.

5.1.1.5 Deflection Limits. The vibrational deflection limit of a piping system depends on a large number of material and geometric considerations with many

Fig. 2 Deflection Measurement at the Intersection of Pipe and Elbow

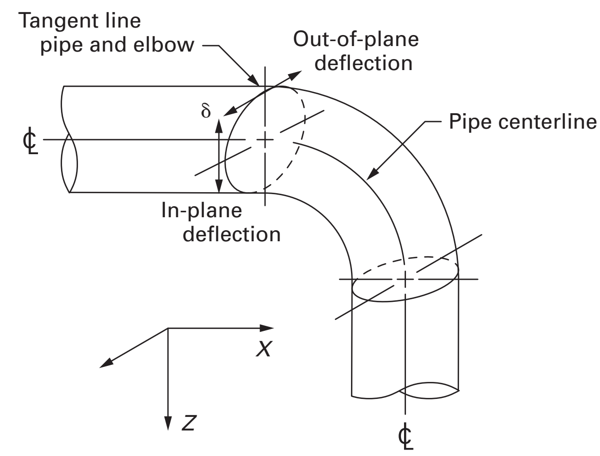


Fig. 3 Single Span Deflection Measurement

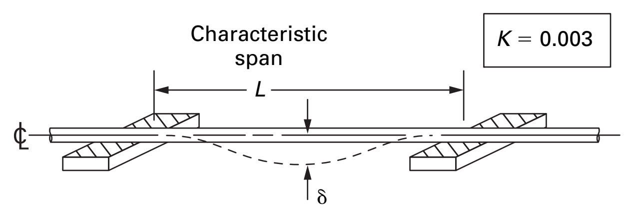


Fig. 4 Cantilever Span Deflection Measurement

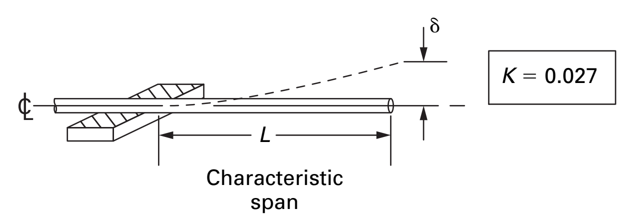


Fig. 5 Cantilever Span/Elbow Span in-Plane Deflection Measurement

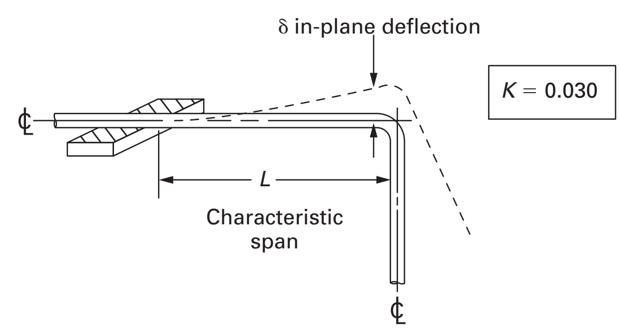


Fig. 6 Cantilever Span/Elbow Guided Span in-Plane Deflection Measurement

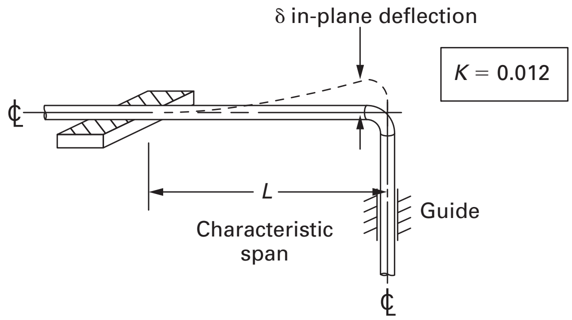


Fig. 9 Span/Elbow Span Out-of-Plane Configuration Coefficient Versus Ratio of Spans

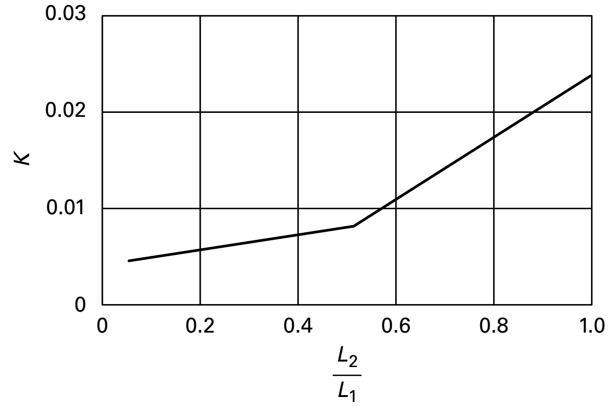
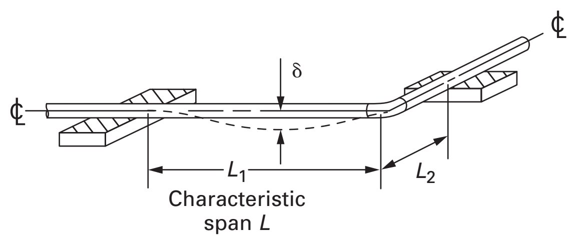
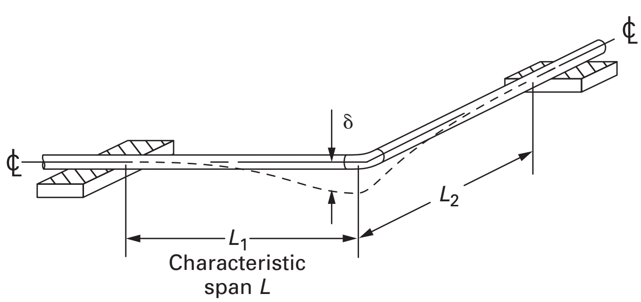


Fig. 7 Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio < 0.5



GENERAL NOTES:
(a) L_2/L_1 less than 0.5.
(b) See Fig. 9 for K.

Fig. 8 Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio > 0.5



GENERAL NOTES:
(a) L_2/L_1 between 0.5 and 1.0.
(b) See Fig. 9 for K.

combinations of the variables. One method of dealing with this complexity is to subdivide the piping systems into characteristic spans that can be physically defined and modeled. A deflection measurement can then be conservatively checked against an allowable deflection limit calculated for that characteristic span. A breakdown of the characteristic spans for which allowable deflection limits have been computed is given in para. 5.1.1.6.

Deflection limits are given in terms of a characteristic span length, outside pipe diameter, and a configuration coefficient. The characteristic span length and the configuration coefficient are established by subdividing the piping system into a series of characteristic spans as described in para. 5.1.1.6.

The configuration coefficient, R, and the nominal vibration deflection, δ_n, values are based on an allowable stress of 10,000 psi with stress indices equal to unity. The allowable deflection limit, δ_{allow}, is shown in para. 5.1.1.5.1.

Where the user demonstrates analytically or by experience that the VMG 2 methods are inherently conservative by at least a factor of 1.3, α may be taken as 1.0. The allowable deflection limit is then compared to the measured value for piping vibration qualification.

5.1.1.5.1 Determination of Allowable Deflection Limit. Nominal vibration deflection value

$$\delta_n = K(L^2/D_o)/144$$

Allowable vibration deflection limit

$$\delta_{\text{allow}} = (S_{\text{el}} \times \delta_n)/(C_2K_2 \times \sigma_n \times \alpha)$$

where

D_o = the outside diameter of the piping, the units of D_o and L are the same (e.g., both in feet or both in meters)

K = the configuration coefficient determined based on a nominal stress (δ_n) of 10,000 psi (68.95 MPa)
L = the characteristic span of the vibrating piping segment
δ_{allow} = the allowable zero to peak vibration deflection limit based on the endurance limit (S_{el}/α) of the piping material and the applicable peak stress indices (C_2K_2)
δ_n = a nominal zero to peak vibration deflection value based on a nominal stress (σ_n) of 10,000 psi (68.95 MPa) and with no consideration of peak stress indices

Paragraph 3.2.1.2 defines S_{el}, α, C_2, and K_2.

5.1.1.6 Characteristic Span Models. It is recommended that the measured deflection data be examined to assist in determining the appropriate characteristic span used to obtain the allowable deflection limit.

Characteristic spans are broadly classified into two categories by the piping restraints. A single-end restraint with one end free forms the first category, and restraint of both ends of a characteristic span forms the second category. The categories are then subdivided into combinations of a single span and two spans joined by a 90-deg elbow. Deflections are measured in the plane of the elbow and out of the plane of the elbow as shown in Fig. 2. The rotational constraint at restraint points is assumed to be fixed for a conservative computation of the allowable deflection limit. An outline of the basic characteristic spans is given below. For any configuration not covered below, a conservative K factor may be established by the user, provided equivalent conservatism is maintained.

(a) Single-end restraint, cantilever
(1) cantilever single span (Fig. 4)
(2) cantilever span, elbow, span
(-a) deflection in plane of elbow, end span free (Fig. 5)
(-b) deflection in plane of elbow, guided end span (Fig. 6)
(b) Restraint at both ends
(1) single span
(-a) single span (Fig. 3)
(-b) single span with elbow restraint [special case of subpara. (b)(1)(-a) or limit case of subpara. (b)(2)(-a)]
(2) span, elbow, span
(-a) maximum deflection measured out of plane of elbow between restraint point and elbow of long span; ratio of short span to long span is less than 0.5 (Fig. 7 with configuration coefficient K from Fig. 9)
(-b) maximum deflection measured out of plane of elbow at intersection of long span and elbow; ratio of short span to long span is between 0.5 and 1.0 (Fig. 8 with configuration coefficient K from Fig. 9)

5.1.2 Velocity Method

5.1.2.1 General Requirements. The method requires consecutive measurements of velocity at various points on the piping system to locate the point that is exhibiting the maximum vibratory velocity. Once this point is located, a final measurement of the maximum velocity, V_{max}, at that point is made and compared with an allowable peak velocity, V_{allow}, as given in para. 5.1.2.4. The criterion for acceptability is

$$V_{max} \leq V_{allow}$$

5.1.2.2 Instrumentation. The instrument used should be portable and capable of making a number of consecutive velocity measurements at various points on the piping. The instrument should be capable of indicating a trace of the actual velocity-time signal from which the maximum velocity can be read. This may be achieved by readout devices such as a cathode-ray tube or a paper chart recorder. Alternatively, the instrument could have a holding circuit that would result in a meter reading of the maximum velocity.

5.1.2.3 Procedure. Initial measurements are to be taken at points on the piping that appear to be undergoing the largest displacements. These will normally correspond to points of the highest velocity. At each such point, measurements can be taken around the circumference of the pipe to find the magnitude of the maximum velocity. Measurements may be confined to directions perpendicular to the axis of the pipe at that point.

The maximum velocity should be obtained only from the actual velocity-time signal. The readout of the signal should be of sufficient duration to ensure a high probability that the maximum velocity has in fact been obtained for that point in that direction.

5.1.2.4 Allowable Peak Velocity. The expression for allowable velocity is

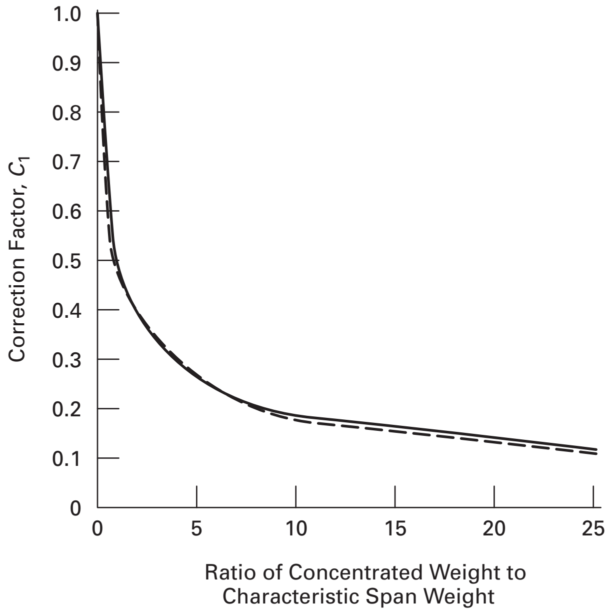
$$V_{allow} = \frac{C_1C_4}{C_3C_5}\frac{\beta\,(S_{el})}{\alpha C_2K_2}$$

where
V_{allow} = allowable velocity, in./sec (mm/s)
β = 3.64×10^{-3} to obtain V_{allow} in in./sec when S_{el} is in units of psi
= 1.34 to obtain V_{allow} in mm/s when S_{el} is in units of MPa

S_{el}, C_2, K_2, and α are defined in para. 3.2.1.2. The secondary stress index C_2 and the local stress index K_2 are associated with the point of maximum stress and not necessarily with the point of maximum velocity.

This velocity criterion is consistent with the deflection criterion for a fixed end beam at resonance in the first mode.

Fig. 10 Correction Factor C_1



C_1 = a correction factor to compensate for the effect of concentrated weights along the characteristic span of the pipe (see Fig. 10)

C_3 = a correction factor accounting for pipe contents and insulation

$$= \left(1.0 + \frac{W_F}{W} + \frac{W_{INS}}{W}\right)^{1/2}$$

C_4 = correction factor for end conditions different from fixed ends and for configurations different from straight spans
= 1.0 for a straight span fixed at both ends, but conservative for any practical end conditions for straight spans of pipe
= 1.33 for cantilever and simply supported pipe span
= 0.74 for equal leg Z-bend
= 0.83 for equal leg U-bend

C_5 = correction factor to account for off-resonance forced vibration, equal to the ratio of the first natural frequency of the piping span to the measured frequency for ratios between 1.0 and 2.0. For ratios greater than 2.0, the C_5 factor is herein undefined. For ratios less than 1.0, the C_5 correction factor equals 1.0.

W = weight of the pipe per unit length, lb/ft (kg/m)

W_F = weight of the pipe contents per unit length, lb/ft (kg/m)

W_{INS} = the weight of the insulation per unit length, lb/ft (kg/m)
= 1.0 for pipe without insulation and either empty or containing steam

Nonmandatory Appendix D presents examples of correction factors C_1 and C_4 for typical piping spans along with a combination of these factors to provide an initial screening method.

5.1.2.5 Precautions. The basic relationship between the allowable velocity and stress is developed from the assumption that the vibratory mode shape matches the mode shape at the first natural frequency. The user is cautioned against indiscriminate use of the velocity criteria without considering velocity, amplitude, frequency, and mode shape of the vibration. The C_5 correction factor modifies the basic relationship to account for off-resonant forced vibrations.

If the piping span is vibrating at frequencies below the first mode natural frequency, then it is inappropriate to use the velocity criteria without the C_5 correction factor since the stresses calculated will be nonconservative, by approximately the ratio of the span natural frequency to the measured forced response frequency, for frequency ratios between 1.0 and 2.0.

For example, if the span natural frequency was 20 Hz and was vibrating at 10 Hz, the stresses predicted from a velocity measurement would be nonconservative by a factor of two, without the C_5 correction factor.

For multispan systems, commonly encountered in power plant piping, caution must be exercised when evaluating stresses caused by resonant excitation from adjacent spans. A determination must be made of the individual span natural frequencies before the decision to use the velocity criteria method can be justified. If the ratio of the first natural frequency of the span to the measured frequency is less than or equal to 2.0, then the velocity method may be used. Values for this ratio greater than 2.0 have not been addressed by this Part.

5.2 Transient Vibration

Another method for the evaluation of vibration of the piping systems is for those subjected to transient loads for which the expected response under the anticipated transient loads is determined by analysis. Piping systems that are not suitable or adaptable to these methods shall be evaluated by the methods of section 6.

5.2.1 General Requirements. This method requires that a dynamic analysis of the piping system subjected to the expected transient loads has been performed yielding the system dynamic responses. Furthermore, the analytical responses must be shown to be conservative through comparison of the analytical responses with those measured during testing. The simplified method requires that dynamic response of piping, at selected locations, be measured. A minimum of two separate remote locations selected for the data points should be based on the analysis performed. In addition, fluid pressure may be measured. The necessary parameters to be measured and their locations shall be included in the test specification.

The criteria for acceptability of the measured data are given in para. 5.2.3. If the criteria specified in para. 5.2.3 are not met, additional evaluation of the piping systems based on the measured data shall be made to justify the acceptance. This may include reanalysis of the piping system based on measured data.

5.2.2 Instrumentation. Appropriate instruments as recommended in section 7 shall be used for obtaining the piping system responses.

5.2.3 Measurements and Criteria for Acceptance. The measured responses shall be compared to the analytically obtained response of the system. If the analysis indicates larger responses than those measured and the general requirements of section 3 concerning analysis versus test conditions have been met, then the vibratory response of the system is acceptable.

5.3 Inaccessible Piping (for Both Steady-State and Transient Vibration Evaluation)

For inaccessible piping systems requiring monitoring, the search procedure for maximum response location is not required. The locations of anticipated maximum response at which measurement devices are to be applied shall be defined. Adequate precautions shall be taken to verify that the assumptions used for the selection of anticipated maximum response locations are consistent with the installed system response.

6 RIGOROUS VERIFICATION METHOD FOR STEADY-STATE AND TRANSIENT VIBRATION

Another method is required when the portion of the system is evaluated in VMG 1 or when the methods of sections 4 and 5 are not applicable or are overly conservative. This method is also intended for application to systems where the dynamic characteristics indicate that the system modes are primarily a result of rocking of massive equipment (such as pumps and heat exchangers). The primary objective of this verification is to obtain an accurate assessment of the vibrational stresses in the piping system from the measured vibrational behavior.

Two acceptable techniques for implementing this method are given in paras. 6.1 and 6.2 along with corresponding requirements. Paragraph 6.1 is supplemented by Nonmandatory Appendices B and C, which describe several methods of implementing this technique. Other techniques may be used provided that they are demonstrated to be conservative.

6.1 Modal Response Technique

6.1.1 General Requirements. This method requires that the modal displacements and natural frequencies of the system be identified from the test data.

The method also requires that a modal analysis of the system be performed yielding analytically determined natural frequencies and mode shapes and modal stress vectors (or bending moments) corresponding to the mode shape vectors. The analysis and test natural frequencies and mode shapes of the piping system shall be correlated, and the analytical stress vectors shall then be used to determine the actual state of stress in the piping due to the measured modal displacements.

6.1.2 Test Requirements. The piping system shall be instrumented sufficiently to enable identification of the natural frequencies and modal displacements. It is not necessary to ensure that the measurements are taken at the location of maximum vibration. The instrumentation may be capable of measuring acceleration, displacement, or velocity according to the guidelines of section 7. Locations of instruments shall correspond closely to points included in the analytical model of the system.

The system shall be exercised through the conditions defined in test specifications. A sufficient amount of data shall be recorded to allow appropriate data processing as described in para. 6.1.3.

6.1.3 Data Processing. Steady-state vibration data shall be reduced to obtain the zero-to-peak displacement in each of the predominant vibrational modes of the system. Methods of determining the modal displacements are available, and two of these are discussed in Nonmandatory Appendix B. When using either of the two methods described in Nonmandatory Appendix B, special attention should be given to separately identify closely spaced modes that may exist in the system.

6.1.4 Test and Analysis Correlation. The measured modal frequencies and modal displacements of the piping system shall be correlated to analytically obtained modal frequencies and mode shapes for all major contributing modes. As a minimum, the test and analytical mode shapes shall correlate with respect to the predominant modal direction; the relative magnitudes of the modal components need not be in exact agreement. In addition, the corresponding modal frequencies of the test and analysis shall be in reasonable agreement.

6.1.5 Evaluation of the Measured Responses. The measured modal displacements of the piping and the correlated analytical results shall be used to obtain an accurate assessment of the vibrational stresses (or moments) in the piping system. A method for obtaining the vibrational stress in the piping using the measured piping displacements and the information from the modal analysis of the system is given in Nonmandatory Appendix C. The resulting vibrational stresses shall be evaluated according to the acceptance criteria of para. 3.2.1.2.

6.2 Measured Stress Technique

Strain gages can be used to directly determine stresses in the piping system during steady-state or transient vibration. This section outlines the general requirements in the use of strain gages. Several precautions associated with the use of strain gages are presented in Nonmandatory Appendix A. These precautions should be considered prior to defining the test program.

6.2.1 General Requirements. The piping system shall be instrumented on straight pipe with a sufficient number of gages near points where maximum stresses in the piping system are expected to occur. Strain gages shall be located remote from points of stress concentration, when used for determining nominal bending moment.

6.2.2 Evaluation of the Measured Responses. The experimentally obtained strains at the instrumented points in the piping system shall be converted to a three-component moment set and evaluated using the acceptance criteria of para. 3.2.1.2.

7 INSTRUMENTATION AND VIBRATION MEASUREMENT REQUIREMENTS

Recognizing the ongoing advancement of data acquisition techniques, the guidelines presented here for the specification of the instrumentation and recording equipment, necessary to meet the minimum monitoring requirements associated with VMG 1, VMG 2, and VMG 3, are not intended to propose methods or techniques. Rather, they set forth the criteria necessary to ensure that the data taken by any method is accurate and repeatable and within the equipment capabilities. Nonmandatory Appendix A contains guidelines and precautions for typical vibration monitoring systems and can be used as a basis for the specification of the system to be used during testing.

Figure 1 shows typical components of a vibration monitoring system.

7.1 General Requirements

The system and techniques used for the vibration monitoring of all piping systems covered by this Part shall meet the minimum requirements described below.

7.1.1 System Specification

(a) A vibration monitoring system (VMS) specification shall be written and included in or referenced by the test specification. The VMS specification shall include the following:

(1) functional description

(2) list of equipment (manufacturer, model number, serial number)

(3) equipment calibration records

(4) equipment specifications

(5) installation specifications

(b) For the VMS, as well as for each device included in the VMS, the following information and minimum requirements shall be contained in the equipment specification, when applicable:

(1) inputs and outputs: units and full-scale range of each

(2) accuracy: specified as a percentage of full-scale physical units

(-a) VMS minimum requirement: greater than 10% of applicable value of acceptance criteria for the measured variable

(3) minimum measurable value

(-a) VMS minimum requirement: less than 80% of applicable value of acceptance criteria for the measured variable

(4) range: full-scale capability with accuracy specification

(-a) VMS minimum requirement: 20% greater than the applicable value of the acceptance criteria for the measured variable

(5) frequency response: minimum and maximum frequencies within specified accuracy

(-a) VMS minimum requirement: frequency response range shall extend one-half octave above and below the maximum and minimum significant frequency range of the measured variable

(6) calibration data: specific requirements in para. 7.1.2

(7) other specifications: any other specifications unique to the measurement system or important for the accurate measurement of the variable (e.g., temperature compensation and mounting requirements)

Manufacturer's specifications are acceptable for each device included in the VMS; however, care should be exercised to ensure that the application, mounting, and interfacing conditions do not affect or invalidate the manufacturer's specifications. This is especially important in transducer mounting and electrical loadings.

An example of the specification is given in Table 2.

7.1.2 Calibration. All equipment used as part of the VMS shall have current calibration documents. These shall be attached to or made part of the system specification. On-site checkout of the VMS shall be performed and documented to verify that the as-installed VMS is functioning according to the system specification.

7.1.3 Repeatability. Capability of the VMS to provide consistent results shall be demonstrated. This can be achieved by taking several consecutive measurements of a stationary variable during pretest setup and checkout. The results of these consecutive measurements should be within minimum accuracy requirements of the VMS specification.

Table 2 Examples of Specifications of VMS Minimum Requirements; Measured Variable — Displacement

Acceptance Criteria, mils (mm)	Accuracy, mils (mm)	Minimum Measurable Value, mils	Full-Scale Range, mils (mm)	Frequency of Response, Hz	Other: Max. Piping Temperature, °F (°C)
10 (0.254)	±1 (0.0254)	<8	12 (0.30)	0.5–60	250 (121)
100 (2.54)	±10 (0.254)	<80	120 (3.0)	0.5–20	300 (149)

7.1.4 Peak Versus rms Measurement. The acceptance criteria in this Part are based on zero-to-peak piping deflections; therefore, the VMS used must result in actual zero-to-peak measurements. If the instrumentation used yields rms measurements, then conservative methods must be used to convert the rms measurements to zero-to-peak values.

8 CORRECTIVE ACTION

Corrective action is required to reduce piping vibrational stresses to acceptable values when piping steady-state or transient vibration exceeds the acceptance criteria of para. 3.2. Possible corrective actions include identification and reduction or elimination of the excitation mechanism or vibration source; structural modifications to detune resonant piping spans; and changes in operating procedures to eliminate troublesome operating conditions.

If corrective restraints, circumferential stiffeners, for example, or system modifications are required to make the piping system acceptable, then the piping system stress analysis shall be reviewed and, as necessary, reconciled.

After corrective action is completed, postmodification testing shall be performed to determine if the vibrations have been sufficiently reduced to satisfy the acceptance criteria. Testing may involve determining the vibration response of the system during specific operating modes to verify adequacy of modifications implemented to control vibration.

Vibration excitation mechanisms and piping responses along with possible additional testing, analysis, and corrective actions are discussed in Nonmandatory Appendix E.

Part 3, Nonmandatory Appendix A
Instrumentation and Measurement Guidelines

The purpose of this Nonmandatory Appendix is to provide guidelines for the selection of devices and components of a vibration monitoring system (VMS). Recognizing that the instrumentation included in the VMS will depend on the method chosen for the measurement program (VMG 1, 2, or 3), this Nonmandatory Appendix provides suggestions, examples, and precautions for the instrumentation and techniques that might be employed for each method.

It is not the intent of this Nonmandatory Appendix to be used in place of state-of-the-art techniques for vibration monitoring.

A-1 VISUAL METHODS (VMG 3)

The visual inspection method allows the use of senses, such as touch, to determine acceptability. For example, with sufficient experience, vibration amplitude can be perceived fairly accurately for frequencies from 2 Hz to 30 Hz by feeling the pipe vibrate. Estimates of the amplitudes of the lower frequency vibrations can be obtained with a scale.

Simple aids, such as those suggested in Part 3, para. 4.2, can be used for estimating the amplitude of displacement for piping classified under VMG 3 when precise results are not required. Even so, the user should be cautioned against attempting to use these simple aids under circumstances where erroneous estimates could be obtained. For example, low-amplitude [<30 mils (<0.76 mm)] vibrations at relatively high frequencies (>20 Hz) would be difficult to quantify with a spring hanger scale. Likewise, low-frequency (<5 Hz) vibrations are usually difficult to read with an optical wedge because the eye's persistence of vision is inadequate to perceive a distinct intersection between the dark and light regions of the wedge.

It is the intent of the visual methods to identify those vibrations that are obviously acceptable. If doubt exists as to acceptability after the visual inspection methods are employed, then the methods of section A-2 of this Nonmandatory Appendix should be employed.

A-2 ELECTRONIC MEASUREMENT METHODS (VMG 2 AND VMG 1)

The following discussions regarding hardware selection and methodology are applicable to both VMG 1 and VMG 2 monitoring requirements.

A-2.1 Transducers

A-2.1.1 Accelerometers. One transducer for vibration measurement is the piezoelectric accelerometer. The advantages of the accelerometer include a capability for high-temperature operation, physical durability and reliability, ease and stability of calibration, intrinsic low noise, linearity over a wide dynamic range, small mass, and ease of application for absolute measurement.

A servo accelerometer that has excellent low-frequency response characteristics can also be used. Its advantages are a high output signal and frequency response down to direct current (dc).

Some accelerometer characteristics are of particular importance for piping measurements.

(a) Variation of Sensor Output With Temperature. If the change in output from room temperature to operating temperature exceeds 10%, a correction factor determined from the Manufacturer's Data Sheet should be applied.

(b) Variation of Sensor Output With Frequency. This variation depends on the type of accelerometer, the mounting technique used, and whether its output signal is fed into a charge-sensitive amplifier or a voltage-sensitive amplifier. Variation of output may be as high as 3% per decade in frequency. If the variation exceeds 10% over the frequency band being measured, data should be corrected in accordance with the Manufacturer's Data Sheet.

(c) Maximum Temperature of Operation. Under no circumstances should the maximum operating temperature specified by the Manufacturer be exceeded. However, direct attachment to the pipe surface is usually feasible because accelerometers with maximum temperature ratings of at least 650°F (345°C) are readily available. Thermally insulated mounts may also be used, if necessary, to reduce the temperature at the accelerometer.

The accelerometer characteristics, such as frequency response and associated electronic circuitry, should be compatible with the required measurement goals. Proper scaling and band-pass filtering should be employed to aid the analyst in obtaining vibration data within the requirements of Part 3, section 7.

Two intrinsic shortcomings of acceleration measurements that may cause difficulties in plant piping applications are low-level, high-impedance output and poor signal-to-noise (S/N) ratio at low frequencies, particularly following the double integration required to obtain displacement.

Should these shortcomings prohibit the use of accelerometers, the user may be able to achieve better performance with the high-output, low-impedance devices described below.

A-2.1.2 Velocity Transducers. Velocimeters (or velocity pickups) are transducers designed to respond directly to velocity. They usually consist of a moving coil or moving magnet arranged so that the electrical output generated is proportional to the rate at which the magnetic field lines are cut by the moving element, and hence its velocity. The main advantage of these electrodynamic transducers over accelerometers is their high-level, low-impedance output, thereby making their signals relatively immune to electromagnetic noise pickup. Their chief disadvantages are their larger size and their somewhat restricted useful linear bandwidth. Contamination from background at low frequencies limits their usefulness in providing displacement indications, since the necessary integration tends to amplify low-frequency noise selectively.

A-2.1.3 Displacement Transducers. Examples of direct-sensing displacement transducers applicable to piping vibration measurements are the eddy current probe (or proximity probe), the linearly variable differential transformer (LVDT), handheld vibrometer, and the lanyard gage potentiometer. All sense absolute displacement relative to a fixed reference and, therefore, have frequency response and S/N curves that are uniform all the way to zero frequency (dc). This is their chief advantage, along with high electrical output and, hence, immunity to extraneous noise. An attendant disadvantage, however, is that they must be mounted firmly to some structure that is stationary relative to the vibrating system whose displacement is to be measured. This is often difficult to accomplish in an operating plant environment. Other disadvantages of these transducers are the following:

(a) some have a lower high-frequency response

(b) limited range of displacement over which the transducer responds linearly and without hysteresis

(c) need for special accompanying electronics (oscillator/demodulator) and cabling

(d) in some cases, high noise, offset errors, and limited (quantized) displacement resolution

A-2.1.4 Special Transducers. Other instrumentation (e.g., laser vibrometers that detect the Doppler shift accompanying motion of the target) is commercially available for those special situations requiring unusually high measurement accuracy or where physical access to the vibrating structure prohibits use of the transducers already described. Such devices are too specialized to warrant further description in this document.

A-2.1.5 Strain Gages. The use of strain gages (μin./in.) at selected points in the piping system provides data that can be used for comparison to acceptance criteria. The type of gages normally used on the piping systems are either the weldable or the bondable types. The temperatures and radiation level typical of power plant environments may limit the use of bondable gages. Weldable gages that will operate for all temperature and radiation levels typical of nuclear power plant environments are available. The usual requirement is that the state of stress at points on the piping system can be determined from strain gage readings. This implies the use of an appropriate theory relating strains to stresses. The validity of the final results depends on the validity of any relationships used in reducing the data.

The user of strain gages must be aware of some problems encountered by the use of these devices, especially for the measurement of static strains. These problems are associated with temperature compensation, bond stability, instrument stability and moisture, radiation, and high-temperature environments. The user should employ state-of-the-art techniques to circumvent these potential problems.

A-2.2 Cables

Since cable noise can distort the vibration signals from sensors, low-noise cable should be used between the sensor and the signal conditioner. The cable should have temperature characteristics adequate for the expected environment.

If cable connectors are used, precautions should be taken to avoid the introduction of moisture at these locations, since, in general, long cable runs [>100 ft (>30.48 m)] between the transducer and the signal conditioning unit may produce high-noise pickup or signal attenuation. A remote preamplifier (or remote charge converter) may be required to avoid these difficulties. The transducer and cable Manufacturer's Data Sheets should be consulted for details.

A-2.3 Signal Conditioner

A-2.3.1 General Requirements. The signal conditioner should have proper electronic characteristics for the selected transducer.

For accelerometer signal conditioning, integrating circuits yielding velocity and displacement outputs from the acceleration signal may be included in the signal conditioner. Gain normalization for direct incorporation of accelerometer output scale factor (as supplied by the Manufacturer) is an important feature because all outputs can then be designed to read out directly in absolute velocity and displacement units.

A-2.3.2 Frequency Range. A working range from 0 Hz to 300 Hz will cover practically all piping applications.

(15) **A-2.3.3 Vibration Scale Range.** The signal conditioner should typically be able to measure velocities from 10^{-2} in./sec to 10^{2} in./sec (0.254 mm/s to 2 540 mm/s) and displacements from 10^{-4} in. to 10 in. (0.00254 mm to 254 mm).

To provide accurate measurements over the wide amplitude ranges specified above, the signal conditioner should provide several fixed-gain adjustments or intermediate full-scale ranges.

A-2.3.4 Filtering. Switch-selected, low-frequency cutoff limits should be provided to eliminate extremely low-frequency signals and unwanted noise.

Low-pass filtering should be available at the upper end of the vibration band to eliminate unwanted high-frequency noise.

Band-pass filtering may often be desirable to reduce interference among sinusoidal amplitude distributions, or pulselike with high-crest factors, and sometimes mixtures of all three. Therefore, the proper amplitude function (rms, peak, peak-to-peak) should be carefully selected, and should be consistent with the acceptance criteria for the measured variable.

A-2.4 Auxiliary Equipment

An oscilloscope for viewing the waveforms of the acceleration, velocity, and displacement outputs from the signal conditioner is desirable in most cases. A real-time frequency analyzer and an analog FM tape recorder (for data preservation and/or additional offline study and processing) are also useful, optional equipment. A strip chart recorder or oscillograph can also be used to provide a permanent record of the analog meter indication.

Part 3, Nonmandatory Appendix B
Analysis Methods

This Nonmandatory Appendix describes two methods of obtaining modal displacements of the piping system from the measured total displacement time history. It is recommended to be used in conjunction with Part 3, para. 6.1.

B-1 FOURIER TRANSFORM METHOD[1]

The recorded acceleration, velocity, or displacement time histories can be converted to a spectral density function using Fast Fourier Transform techniques. The spectral density should be computed in the frequency range that contains the expected predominant system response. A sufficient number of spectral averages should be made to ensure that the density function has converged. Integration of the density function over discrete frequency bands around the predominant modal responses yields the rms modal response. These can readily be converted to peak-to-peak response through consideration of the statistical properties of the response.

In addition to the modal responses, the spectral density function will indicate the system response at deterministic frequencies associated with shaft and blade passing frequencies of rotating equipment that excite the piping system.

The piping displacements at these frequencies should be determined. The piping displacements at these frequencies should be absolutely summed with the modal displacement of the piping system mode that is nearest to the deterministic frequency or that closely resembles the displaced configuration at the deterministic frequency.

B-2 OTHER METHODS

Alternative methods may be employed, such as modal superposition, provided that the method used is demonstratively conservative and the test analysis correlation requirements of Part 3, para. 6.1.4 are met.

[1] The user of this method is referred to the latest revision of ANSI S2.10, Methods for Analysis and Presentation of Shock and Vibration Data.

Part 3, Nonmandatory Appendix C Test/Analysis Correlation Methods

This Nonmandatory Appendix presents a method for converting measured modal displacements of the piping system to bending stress (or bending moments) through the use of analytically obtained modal characteristics.[1] It is recommended to be used in conjunction with Part 3, para. 6.1.

C-1 TEST/ANALYSIS CORRELATION

The modal displacements at each measurement point, obtained in Part 3, para. 6.1.3, should be tabulated and normalized to an appropriate value (such as the maximum displacement) in that mode. The relative sign of each displacement can be obtained by computing the phase between measurement points using Fourier Transform techniques. This yields a normalized mode shape and modal frequency obtained by test that can be compared to analytically obtained normalized mode shapes and frequencies. The test and analytical results should be correlated according to the requirements of Part 3, para. 6.1.4.

C-2 EVALUATION OF THE MEASURED RESPONSES

Having achieved a correlation of test/analysis results, the analytically obtained modal moments or stresses in the system piping can be determined using the actual modal responses obtained from the test data. This can be done in the following way.

The measured modal displacement at point j in mode i (denoted by D_{ij}^T) is divided by the corresponding analytical displacement (D_{ij}^A), yielding the modal response factor K_{ij}, as shown below.

$$K_{ij} = \frac{D_{ij}^T}{D_{ij}^A}$$

Theoretically, all K_{ij} within a mode should be the same if perfect correlation of test and analytical mode shapes has been achieved. Realistically, however, the K_{ij} will vary. Therefore, for each mode the maximum K_{ij} is chosen as the modal response factor for mode i (denote as K_i). The maximum K_{ij} should be chosen from among those K_{ij} in the direction of predominant modal motion to reduce unnecessary conservatism. Having obtained the modal response factors (K_i) for each mode, the test stress vector (S_j^T) for each mode should be calculated by premultiplying the analytical stress vector[1] $(S_j^A)_i$ by the modal response factor:

$$(S_j^T)_i = K_i(S_j^A)_i$$

The modal stress vectors thus obtained should be combined by an appropriate conservative method to obtain the total stress in the piping.

[1] It is assumed in this method that the stress vector includes the stress indices as defined in Part 3, para. 3.2.1.2. Alternatively, the modal bending moments in the piping (obtained from the modal analysis of the piping) can be converted to stress using the equation for S_{alt} defined in Part 3, para. 3.2.1.2.

Part 3, Nonmandatory Appendix D Velocity Criterion

This Nonmandatory Appendix describes a method for establishing a velocity criterion for screening piping systems. Using these procedures, piping systems requiring further analysis can be determined. This Nonmandatory Appendix is to be used in conjunction with Part 3, para. 5.1.2.4.

D-1 VELOCITY CRITERION

The expression for allowable peak velocity from Part 3, para. 5.1.2.4 is

$$V_{\text{allow}} = \frac{C_1 C_4}{C_3 C_5} \frac{\beta(S_{\text{el}})}{\alpha C_2 K_2}$$

where

C_1 = correction factor that compensates for the effect of concentrated weights. If concentrated weight is less than 17 times the weight of the span for straight beams, L-bends, U-bends, and Z-bends, a conservative value of 0.15 can be used for screening purposes.

C_2K_2 = stress indices as defined in the ASME Code; $C_2K_2 \leq 4$ for most piping systems

C_3 = correction factor accounting for pipe contents and insulation; for contents and insulation equal to the weight of the pipe, the value would be 1.414; in most cases it is less than 1.5

C_4 = correction factor for end conditions different from fixed ends and for configurations different from straight spans
= 1.33 for cantilever and simply supported beam
= 0.74 for equal leg Z-bend
= 0.83 for equal leg U-bend
= 0.7 as conservative value for screening purposes

C_5 = correction factor that is used when measured frequency differs from the first natural frequency of the piping span; for frequency ratios less than 1.0, the value is 1.0

S_{el} = see Part 3, para. 3.2.1.2

α = see Part 3, para. 3.2.1.2

β = see Part 3, para. 5.1.2.4

D-2 SCREENING VELOCITY CRITERION

If conservative values of the correction factors are combined, a criterion can be derived that should indicate safe levels of vibration for any type of piping configuration. Using this criterion, piping systems can be checked and those with vibration velocity levels lower than the screening value would require no further analysis. Piping systems that have vibration velocity levels higher than the screening value do not necessarily have excessive stresses, but further analysis is necessary to establish their acceptability.

The following correction factors are considered to be conservative values and should be applicable to most piping configurations; however, the conservatism for extremely complex piping configurations cannot be attested.

C_1 = 0.15

C_2K_2 = 4

C_3 = 1.5

C_4 = 0.7

C_5 = 1.0

S_{el}/α = 7,690 psi (53 MPa)

V_{allow} = screening vibration velocity value

$$= \frac{(0.15)(0.7)(0.00364)(7{,}690)}{(1.5)(1.0)(4)}$$

= 0.5 in./sec (12.7 mm/s)

D-3 USE OF SCREENING VIBRATION VELOCITY VALUE

A screening vibration velocity value of 0.5 in./sec (12.7 mm/s) has been established that can be used in conjunction with Part 3, para. 5.1.2.4. Piping systems with peak velocities less than 0.5 in./sec (12.7 mm/s) are considered to be safe from a vibratory stress standpoint and require no further analysis. If vibrational velocities greater than 0.5 in./sec (12.7 mm/s) are measured, then further analyses are required to determine acceptability.

The first step to take if vibration velocities are greater than 0.5 in./sec (12.7 mm/s) is to determine more accurate values of the correction factors C_1, C_3, C_4, C_5, and the stress indices C_2K_2 so that the applicable velocity criteria for the piping system in question can be established.

Part 3, Nonmandatory Appendix E Excitation Mechanisms, Responses, and Corrective Actions

E-1 EXCITATION MECHANISMS AND PIPING RESPONSES

Piping vibrational response can be in the form of beam or shell-wall vibration. Each of these responses affect piping differently, and therefore the corrective action required for each should address the specific type of vibration being experienced. Examples of commonly encountered excitation mechanisms and piping responses are given in paras. E-1.1 and E-1.2, respectively.

E-1.1 Excitation Mechanisms

Piping vibration excitation mechanisms are pressure pulsations in the fluid or gas being transported by the piping or vibrations mechanically transmitted by attached or adjacent equipment.

Examples of potential sources of low-frequency vibration are control valve oscillations, turbulence caused by high flow velocities, flashing, and cavitation. These sources can be reduced by valve control system modifications such as the addition of damping, routing, or pipe size changes to reduce turbulence, and the use of breakdown orifices or anticavitation valve trim to reduce flashing or cavitation.

Examples of high-frequency vibration sources are pump- or compressor-induced pressure pulsations produced by a control valve in a gas or steam system and vortex shedding at flow orifices in a water system. Modifications such as using a muffler, pulsation dampener or suction stabilizer, noise reduction valve trim, or adding multistage orifices are examples of how the vibration source can be reduced.

Pressure disturbances or pulsations are transmitted through the fluid the same way that sound is transmitted through air. Pressure pulsations can be amplified if the pulsation frequency is at or near a piping acoustical frequency; this resonant condition increases the potential for detrimental piping vibration. Acoustic frequencies are a function of the speed of sound in the fluid or gas and are inversely proportional to the piping length.

A common excitation mechanism is vortex shedding at flow discontinuities. Vortex shedding causes pressure pulsations at the distinct frequency ranges. If the shedding frequency is close to a piping acoustical natural frequency, then resonance can occur and the pulsations would be amplified. Modifying the discontinuity (e.g., flow orifice of side branch opening) can reduce the vortex shedding and shift the shedding frequency, thereby avoiding resonance. If this cannot be done, then modifications can be made to change the acoustic frequencies of the piping. Acoustic modifications include changes in pipe lengths to raise or lower its acoustical natural frequency, and the addition of a muffler, pulsation dampener, or suction stabilizer.

E-1.1.1 Cavitation. Cavitation is often the cause of piping vibration and also produces noise, pressure, fluctuations, erosion damage, and loss of flow capacity. How it occurs, its progression, and the involvement of piping components are described below. A case history is also provided that demonstrates how detrimental cavitation can occur at off-normal operating conditions.

E-1.1.1.1 Commentary. Vapor cavities are formed when liquid pressure falls below its vapor pressure, which can occur at pressure-reducing orifices and flow control valves. Cavitation occurs when a vapor cavity collapses as it is subjected to pressure greater than its vapor pressure. This can occur when a vapor cavity moves downstream of the orifice or valve. Collapse of the cavities produces pulsations, which can cause pipe vibration, surface erosion, and accelerated corrosion.[1,2]

Cavitation sounds different depending on its severity. It can vary from a cracking sound to a sound resembling gravel being transported through a pipe. At severe levels it can be damaging to hearing.

When the vapor cavities collapse next to a pipe or component surface, erosion and corrosion can occur. Cavitation erodes the protective oxidized surface, which allows corrosion to accelerate. Recent pipe failures and leakages have led to research to monitor and remedy the offending conditions.[3]

Components in piping systems, which contribute to the pressure decrease necessary to cause cavitation, are valves, orifices, nozzles, pumps, and elbows. Damage can be reduced by keeping the cavitation level low, removing the boundary from the cavitation zone, treating the boundary surface to make it resistant to damage, dissipating the flow energy in stages, or ejecting air into the separation regions.[4] The most certain treatment for

[1] Olson, D. E., "Piping Vibration Experience in Power Plants," Pressure Vessel and Piping Technology (1985), A Decade of Progress, Book No. H0030, The American Society of Mechanical Engineers (ASME).

[2] Wachel, J. C., et al., "Piping Vibration Analysis," Turbomachinery Symposium (September 1990).

[3] "Cavitation Erosion Model," Electric Power Research Institute Report, NATS RT-103193 (December 1993).

[4] Tullis, J. P., "Hydraulics of Pipelines," John Wiley and Sons, New York (1989).

cavitation-produced pipe vibration is to reduce or eliminate the source.

E-1.1.1.2 Case History — Cavitation at Orifices. The chemical and volume control system (CVCS) in some pressurized water reactor plants contains a single stage stepdown orifice in the Letdown portion of the system. The orifice has a bore of 0.25 in. and a length of approximately 24 in. The pressure drop across this orifice is approximately 2,000 psig (from an upstream reactor coolant system pressure of 2,250 psig to a downstream pressure of about 250 psig). A back pressure of 200 psig or larger is required to prevent cavitation from occurring at the discharge end.

At one nuclear plant, the pressure at the discharge end dropped to approximately 100 psig when a pressure instrument drifted out of calibration. This condition was discovered after 9 months of operating under this condition and the system was reconstituted to its design conditions. However, this extended period of operation outside the design differential pressure condition was sufficient to cause cavitation and subsequent erosion at the discharge end of the orifice. This erosion adversely affected the fluid characteristics at the discharge end causing continuous cavitation, which continued to worsen even under design pressure conditions.

The cavitation excited the piping system. The vibration levels were sufficient to cause leaks in the socket welded joints. The joints were repaired using similar design details, but they continued to fail at ever increasing rates as the orifice continued to erode due to the continuing cavitation.

A review of plant records revealed that the previous operation was outside the design back pressure requirement. An engineering evaluation indicated the potential for cavitation and possible erosion of the orifice. The cavitation and socket weld failures ceased after the orifice was replaced.

E-1.2 Piping Responses

Piping beam vibration is the most commonly encountered response. This vibration results from excitation of piping structural modes that cause piping to vibrate similar to simple beams. This type of vibration is typically most predominant below 20 Hz although beam vibration with frequencies up to 100 Hz or more is possible. Eliminating or reducing the vibration excitation source is the most effective corrective action. Low-frequency beam vibration can also be adequately restrained through the addition of supports.

Experience has shown that the most effective use of restraints is obtained by supporting piping near bends and at all heavy masses and piping discontinuities. Vibrations of vents, drains, bypass, and instrument piping can be corrected by bracing the masses (valves, flanges, etc.) to the main pipe to eliminate relative vibrations.

Supports and structures used to restrain piping vibration must be capable of enduring the continuous vibration loadings that they are installed to restrain. This vibration can result in excessive wear and fatigue of components and supports not specifically designed for vibration. Therefore, items installed for this purpose must be able to withstand this vibration, or inspections and replacements of these items should be scheduled.

High-frequency piping vibration results in small displacement amplitudes, on the order of several mils or less, and is commonly prevalent throughout a large portion of a piping system. Therefore, the addition of supports is typically not an effective means of controlling high-frequency vibration. For example, the free play inherent in most supports would not restrain high-frequency vibration.

Piping shell-wall vibrations typically occur at high frequencies. For example, the lowest frequency shell mode of vibrations for a 24 in. Schedule 40 pipe is 190 Hz. Piping shell-wall vibration frequencies are proportional to the pipe-wall thickness and are inversely proportional to the pipe diameter. The most effective corrective action for shell-wall vibration is to eliminate the vibration excitation source. If the source cannot be adequately reduced, then the shell wall vibration frequency must be moved out of resonance, which could involve changing the pipe dimensions, such as using a heavier wall pipe. Circumferential stiffeners may also be used to increase the piping shell wall frequency. Constrained layer damping can be added to reduce the dynamic response and stress.

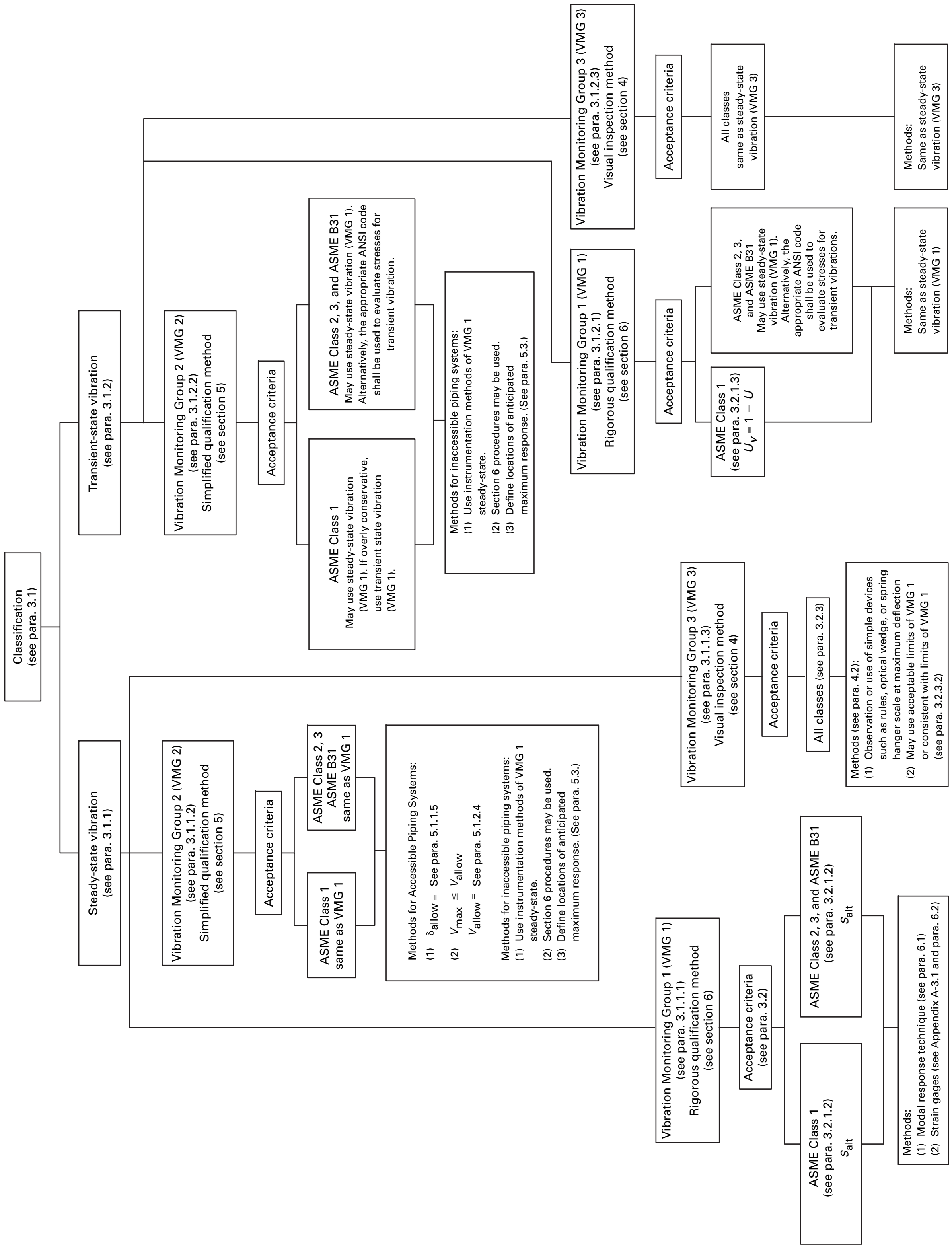
E-2 ADDITIONAL TESTING AND ANALYSIS

Root cause investigation may also involve more detailed analysis and/or testing. These steps can be taken to assist in determining the root cause of the vibration, or to reduce possible conservatism in the methods used to determine vibrational stresses. For example, vibration that exceeds the limits determined through the simplified evaluation techniques given in Part 3, section 5 may be demonstrated to be within acceptable limits when more detailed techniques are used. The methods of Part 3, section 5 were developed to be efficient methods of qualifying the majority of piping; however, conservative assumptions were made to simplify the criteria. Therefore, by either more detailed analysis and/or testing, higher vibrational displacements may be justified. More detailed analysis may, for example, include the methods described in Part 3, section 6 or finite element modeling of a particular structure or component. Detailed testing can involve the application of strain gages to determine with a higher degree of accuracy the actual peak stress levels in the piping. Strain gage testing may also be used, possibly in conjunction with test and analysis correlation, to reduce conservatism. A continuous monitoring data acquisition system may also be temporarily used to determine system vibrational response during plant operation.

Part 3, Nonmandatory Appendix F
Flowchart — Outline of Vibration Qualification of Piping Systems

Figure F-1, Flowchart — Outline of Vibration Qualification of Piping Systems, appears on the following page.

Fig. F-1 Flowchart — Outline of Vibration Qualification of Piping Systems



Part 3, Nonmandatory Appendix G
Qualitative Evaluations

For a piping system to be deemed acceptable, the observed piping vibration must also be acceptable based on qualitative evaluations made during the walkdown. This is in addition to demonstrating acceptability based on the quantitative measurements and calculations of VMG 1, 2, or 3. Qualitative evaluations are made without the aid of measurement data or made in addition to measured data. Qualitative evaluations of observed piping responses are made based on comparisons to known acceptable responses.

Qualitative evaluations are not acceptable if the observed conditions are judged to have a detrimental impact on the integrity of the piping system (i.e., the capability to maintain pressure integrity or perform its safety function). Conditions judged to affect only the maintenance of the system, but not its integrity, can be considered acceptable but should be flagged for future corrective action and/or monitoring. Caution must be used when touching high-temperature or high-energy piping.

Qualitative evaluations rely primarily on observations and judgments made during the piping walkdowns. Observations include the use of perceptual (visual, tactile, aural) inspections. This includes listening for abnormal noises, for example, due to excessive cavitation or component malfunction. In addition, the sense of touch can be used to determine the presence of high-frequency vibration (i.e., it may not be possible to visually perceive high-frequency vibrations; however, they are readily detectable through the sense of touch).

Items addressed by qualitative evaluations include

(a) applicable assumptions and limitations of the quantitative analysis techniques.

(b) potential detrimental effects of vibration on support wear and fatigue and pipe wall wear caused by rubbing at supports.

(c) the potential effect of vibration on threaded connections such as the loosening of nuts and bolts.

(d) component wear and corrosion (e.g., cavitation can result in significant wear and corrosion).

(e) vibration effects on equipment and components. Vibration can affect valve components such as attached hydraulic and instrumentation tubing and valve yokes. Vibration near a pump can be indicative of pump problems such as misalignment, cavitation, or imbalance.

(f) how limitations of the instrumentation affect the accuracy of the vibration measurements.

(g) signal noise. The contribution of undesirable electrical noise to the vibration signal.

(h) branch lines. Header vibration can adversely affect branch piping, and pressure pulsations transmitted to the branch piping can result in vibration throughout the branch piping.

Part 3, Nonmandatory Appendix H Guidance for Monitoring Piping Steady-State Vibration Per Vibration Monitoring Group 2

H-1 PURPOSE

The purpose of this Nonmandatory Appendix is to provide guidance for monitoring and qualifying, using the displacement acceptance criteria, steady-state piping vibrations per the requirements of Vibration Monitoring Group 2, VMG 2, of Part 3. This guidance is based on extensive experience associated with field walkdowns and testing.

H-2 ASSUMPTIONS

These criteria assume that the stresses resulting from the steady-state vibration of an entire piping system can be conservatively estimated by dividing the system into smaller piping spans with various end conditions and using simple beam analogies to determine the deflection limits. It is further assumed that the vibration between node points and/or adjacent, parallel, seismically rigid restraints is dominated by a single mode of vibration that can be conservatively approximated by the fundamental mode of a simple beam model.

The allowable stress amplitudes, S_a, are in accordance with Part 3, section 3. These stress amplitudes are based on 80% of the alternating stress intensity at 10^6 cycles divided by a stress reduction factor of 1.3 for carbon steels, and the minimum alternating stress intensity at 10^{11} cycles for stainless steels. The values of alternating stress intensity are taken from Fig. I-9.1, I-9.2.1, or I-9.2.2 of the ASME BPV Code, Section III, Appendix I. Note that the assumptions stated in the ASME BPV Code for the use of these curves must be followed, including the following:

(a) The fatigue curves are not applicable at temperatures above 700°F for carbon steel and 800°F for stainless steel.

(b) The fatigue curves use a modulus of elasticity of 30×10^6 psi for carbon steel and 28.3×10^6 psi for stainless steel. Therefore, when an analysis is performed to determine vibration-induced stresses using a modulus of elasticity different than that used in the fatigue curves, the calculated stresses shall be adjusted as specified in ASME BPV Code, Section III, NB-3222.4.

H-3 IMPLEMENTATION

A sample steady-state vibration monitoring procedure is shown in Fig. H-1. The procedure begins with the least involved method of monitoring, and the monitoring methods and associated analyses become more extensive as the measured vibration exceeds the criteria of the various monitoring levels. The procedure requires further action for evaluating vibrations that exceed all levels of acceptance criteria. The procedure is discussed in paras. H-3.1 through H-3.2.4.

H-3.1 Quantitative Evaluations

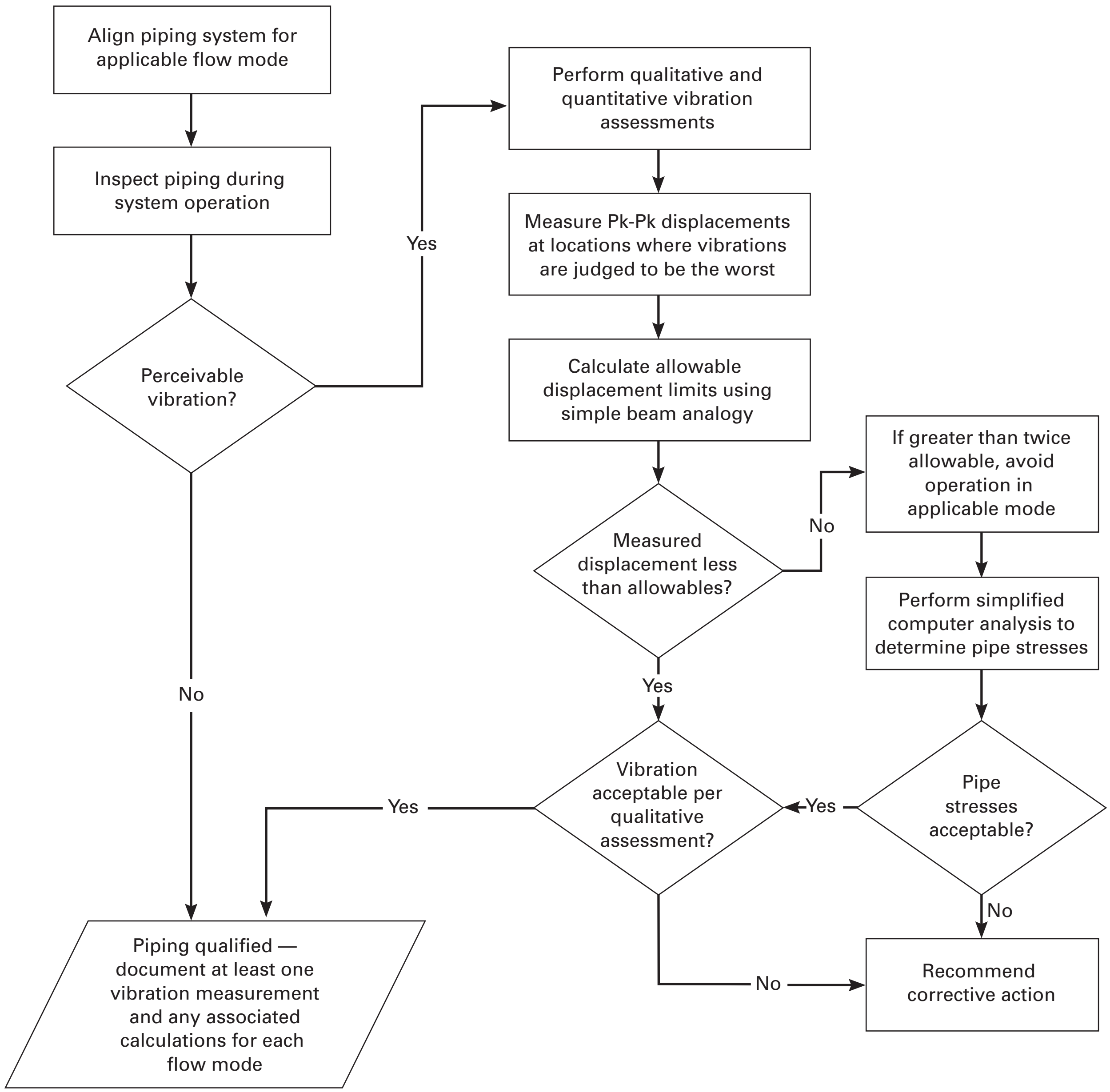
H-3.1.1 Determine Flow Modes to Be Monitored. The first step in implementing the monitoring procedure is to align the piping system in the flow mode(s) that have been judged, based on a review of all the possible operating modes of the system, to result in the most severe vibrations. If the most severe mode(s) cannot be determined from a review of the operating modes, the system should be tested in several or all its operating modes. Generally, the most severe steady-state vibrations occur during maximum or minimum flow conditions.

H-3.1.2 Inspect the Piping. Once the flow mode is established, the piping is inspected for perceivable vibration. Vibrations can be perceived not only by sight but also by touch and by hearing. Therefore, all senses should be alert when performing the walkdown, especially since lighting is usually not ideal and the piping may not be easily accessible.

H-3.1.3 Take Measurements. Even if the vibration appears to be minimal, at least one vibration measurement should be taken to document system response and provide a baseline for future reference. Equipment that measures true peak-to-peak displacement is recommended for measuring piping vibration, since the displacement is proportional to the pipe mode shape and, therefore, is proportional to the vibrational stress.

Equipment that measures root mean square (rms) displacement indicates only an averaged stress. The rms measurement cannot be readily converted to peak-to-peak measurements, except for pure sinusoidal signals. Since piping vibration is often quasirandom, equipment that measures rms signals should not be used. The predominant frequency of the vibration is also important and should be documented for baseline purposes and for aiding in problem resolution.

Fig. H-1 Monitoring and Qualification of Piping Steady-State Vibration



Normally, perceivable vibration exists at several locations on the piping system. Since it is usually not feasible, or necessary, to take vibration measurements at every location, measurements are taken at locations where the vibration is judged to be the worst on the basis of producing the highest vibrational stresses and/or on the basis of the qualitative evaluation.

The worst vibration does not always correspond to the location of the maximum displacement. For example, a displacement measured in a stiff portion of the piping system could be more severe than a large displacement measured in a more flexible portion of the system if the former results in a higher stress. Note that experience in monitoring piping vibration is required to accurately judge the locations of worst vibration and acquire a "feel" for the severity of vibration in general.

H-3.1.4 Evaluate Measurements. Once the locations of the worst vibrations are determined, the measured displacements are evaluated by applying the criteria presented in section H-4. Documentation of the measurement should include the vibration location, magnitude, direction, and frequency, all the calculations performed, and the acceptability of the vibration.

The criteria in section H-4 are simplified for easy application and, because of their simplicity, yield smaller allowable displacements than more detailed analyses would. Knowledge of piping structural dynamics and stress analysis is required to ensure the criteria are applied in a conservative manner.

H-3.1.5 Excess Vibration. If the measured displacement (VMG 2) exceeds the allowable displacement from section H-4, further analysis is required to evaluate the vibration. When the allowable displacement is exceeded by more than a factor of 2, operation of the system in the offending mode flow should be avoided until further analyses or corrective action can be performed. Note that, based on experience, the simplified displacement allowables determined using the simple beam analogies of VMG 2, have typically been found to be conservative by at least a factor of 2, when compared to more detailed evaluations. This assumes the correct application of the criteria.

When the allowable displacement limit is exceeded, a simplified computer analysis can be performed. The purpose of this analysis is to reduce the conservatism inherent to the allowable displacement criteria by more accurately modeling the piping configuration and determining the piping deflected shape and pipe stresses.

The peak stresses from the simplified computer analysis are compared with the applicable allowable stress amplitude from Part 3, section 3. If the allowable stress amplitude is exceeded, further action is recommended to resolve the vibration problem. Examples of recommended actions are shown in Table H-1. The most cost- and time-effective action is chosen for resolving the vibration problem.

H-3.2 Qualitative Evaluations

The objective of the qualitative evaluations is to address vibration causes and effects that are not quantified by the vibration measurements and evaluation techniques. For a piping system to be determined acceptable, the observed piping vibration must be acceptable based on a qualitative evaluation. This is in addition to demonstrating acceptability based on quantitative measurements and calculations.

Note that for the qualitative evaluation to be not acceptable, the observed conditions must be judged to have an immediate detrimental impact on the acceptability of the piping system. An example is severe cavitation that is judged to likely result in damage to the piping or components. Conditions that are judged not to have an immediate detrimental impact can be considered acceptable but should be flagged for future corrective action and/or monitoring. An example is vibration resulting from imbalance in a pump. This may not be an immediate concern, but should be flagged for future corrective action or maintenance.

Qualitative evaluations rely primarily on the observations, experience, and judgments made by the individuals completing the piping walkdowns. Observations include the use of instrumentation plus the use of perceptual inspections, listening for indicative noises, and the sense of touch, which can be used to determine the presence of high-frequency vibration. *Caution must be used when touching high-temperature or high-energy piping.*

Qualitative evaluations assess the potential for detrimental vibration that may not be quantified by the vibration instrumentation. These evaluations also address the limitations inherent to the assumptions and analysis techniques used for quantifying the effects of the vibration on piping response.

Examples of the items that are addressed by the qualitative evaluations include the limitations of the vibration instrumentation and the quantitative analysis techniques and the effect of vibration on supports, equipment, and branch piping. Some specific examples are provided in paras. H-3.2.1 through H-3.2.4.

H-3.2.1 Vibration Instrumentation. Vibration instrumentation is designed to measure specific types and ranges of vibration. The capabilities and limitations of the instrumentation must be accounted for. For example, accelerometers are typically not sensitive to low-frequency vibration. If low-frequency vibration (e.g., less than 3 Hz) is present, then different instrumentation may be required to adequately quantify the vibration.

Table H-1 Recommended Actions for Piping Vibration Problem Resolution

Action	Purpose	Example	Retest Required
Perform detailed analysis	Quantify stresses in localized area; detailed analysis performed to reduce conservatism in simplified analysis	Finite element analysis of stresses in fitting and/or piping structural stress analyses to more accurately quantify the vibrational deflected shape and corresponding stresses	No
Perform detailed testing	Quantify stresses in localized area; detailed testing performed to reduce conservatism in simplified analysis	Installation of strain gages on piping	No
Perform test–analysis correlation	Quantify pipe responses throughout system by correlating analysis input with test data	Use of dynamic pressure data for comparison with input or as input to hydraulic transient analysis	No
Modify piping and/or restraints	Reduce pipe stresses by reducing vibration amplitudes	Addition of rigid restraints	Yes
Determine and eliminate source of vibration	Reduce pipe stresses by eliminating or altering excitation forces	Addition or modification of restricting orifice or valve trim; change in operating procedure	Yes

Additionally, some instrumentation such as displacement transducers, may have limited response to high-frequency vibration. Therefore, if high-frequency vibration is present, different instrumentation (e.g., accelerometers) may be required to obtain adequate measurements.

The limitations of the signal conditioning together with the data acquisition and reduction equipment must also be considered. For example, the types of filters used will affect the recorded data. Filters include high-pass, low-pass, and anti-aliasing filters.

H-3.2.2 Quantitative Analysis Techniques. The acceptance criteria provided in these guidelines are based on the allowable stress limit for fatigue of the piping material. The intent is to prevent a fatigue failure of the piping. However, parameters in addition to pipe fatigue stress can be important. These other factors are evaluated as part of the qualitative evaluation. Other factors include the capability of the support system to withstand the vibration and the effect of vibration on associated equipment and branch lines.

The simplified evaluation techniques are based on the piping vibrating in beam modes. High-frequency vibration may excite piping shell modes and can result in vibration that cannot be adequately evaluated using only beam mode analogies.

H-3.2.3 Piping Supports. Piping vibration can affect pipe supports by causing wear, loosening of threaded connections, and fatigue damage. These effects must be evaluated if the vibration is judged significant enough to adversely affect the supports. Although the acceptance criteria for the simple span analogies are based on piping fatigue stress limits, the supports are obviously important since damage or failure of a support could adversely affect the vibrational response of the piping.

Quantitative evaluation of stress in the structural members comprising the support should be completed when significant vibrational loads are experienced.

The following are examples of qualitative evaluations of supports that should be completed as appropriate:

(a) inspection for loose or missing nuts at threaded connections. Vibration, especially high-frequency vibration, tends to loosen threaded connections.

(b) indications of wear at the interface of the piping and components of guide-type supports. Vibration can cause the piping to rub, potentially resulting in wear of both the piping outside wall and support components. For active restraints, especially snubbers, continuous vibration can cause degradation of internals (e.g., wear). Wear can also result between the clevis pin and clamp or end bracket.

(c) moved, rotated, or misaligned pipe clamps. Moved, rotated, or misaligned pipe clamps can be indicative of piping dynamic transients or significant steady-state vibration.

H-3.2.4 Equipment. Piping vibration can adversely affect associated equipment such as pumps, valves, and orifices. Inline instrumentation can also be adversely affected. Qualitative evaluations are intended to also address the potential for vibration damage to equipment. Below are examples of items to consider.

(a) Cavitation results in piping vibration, which is evaluated through quantitative techniques. However, cavitation can also cause wear, erosion, and pitting on the internal surface of valves, downstream piping, and orifices. The presence of significant cavitation, typically accompanied by continual or intermittent loud noise, may be reason to fail the qualitative evaluation, even if the quantitative evaluation indicates acceptable results.

(b) Vibration can affect equipment components. Vibration can affect components of the valve such as attached hydraulic and instrumentation tubing and valve yokes. The presence of high-frequency vibration at a valve could also be indicative of resonance of the valve internals.

(c) Vibration near a pump can be indicative of pump problems such as misalignment, bearing wear, flow recirculation, internal cavitation, or imbalance.

(d) Branch lines can be affected by vibration of the header piping especially if the header vibration frequency is near a structural natural frequency of the branch piping. Branch piping can also be affected by the pressure pulses in the header being transmitted through the branch. This is especially true if an acoustic resonance of the branch piping is excited.

H-4 ALLOWABLE DISPLACEMENT LIMIT

The measured displacements obtained during the perceptual monitoring procedure (section H-3) are compared with allowable displacement limits. The displacement limits are calculated using the beam models and corresponding equations given in Part 3, para. 5.1.1. These beam models correspond to conservative representations of the actual piping response. Guidance on the use of these models are provided in paras. H-4.1 and H-4.2.

H-4.1 Characteristic Span

Characteristic span is the span of piping (L, ft) that is used in the allowable displacement limit equations to obtain an allowable vibrational displacement (δ_{allow}) and is the length of pipe between adjacent vibrational node points. If vibrational node points cannot be determined, such as is the case with quasirandom vibration, a conservative characteristic span should be determined by using assumed node points. The location and orientation of the seismically rigid supports (e.g., snubbers, rigid struts, structural anchors, and equipment nozzles) can be used as assumed node points. The assumed node points are then used to determine the characteristic span.

Note that a conservative characteristic span is a length of pipe that is shorter than the actual vibrating span of pipe. As illustrated by the allowable displacement limit equations, the rate of decrease of δ_{allow} is proportional to the squared rate of decrease of the characteristic span, L.

H-4.2 Node Points

Node points are locations of zero pipe vibrational displacement ($\delta = 0$). Note that beam analogies that have one or both ends assumed to be fixed or clamped conservatively assume that node point locations experience zero rotation as well as zero displacement. Node points are most readily found when the piping is vibrating predominantly in a single mode of vibration. Node points will typically occur at seismically rigid restraints; however, node points may also occur in the middle of pipe spans. As discussed previously, assumed node point locations may have to be used for determining the characteristic span if actual node points cannot be determined.

It should be noted that node points are not always located at restraints. For example, snubbers limit vibrational motion to a predetermined velocity or acceleration value. If the piping is vibrating at a level below the predetermined value (e.g., below 0.02 g for certain mechanical snubbers or below 10 in./min velocity for some hydraulic snubbers), the snubber will not restrain the piping and the restraint location and, therefore, need not be considered as a node point.

In addition, some restraints may have gaps or free play of sufficient magnitude to allow unrestrained piping vibrations of a magnitude less than or equal to the restraint gaps or free play. For piping vibrational displacements of a magnitude less than or equal to the restraint gaps or free play, the restraint locations need not be considered as node points.

Part 3, Nonmandatory Appendix I Acceleration Limits for Small Branch Piping (15)

The intent of the acceleration method is to provide screening acceleration limits as a supplement to the displacement limits discussed in Part 3, section 5 for small branch piping (pipe sizes ≤2 in.) with significant masses cantilevered from header piping or equipment. This method is intended to provide a conservative representation of the vibrational stresses in the branch connection between the small branch piping and the header.

These limits can be used to screen out configurations with acceptable vibration levels from those that may be unacceptable or may require more detailed evaluations to demonstrate the acceptability of the vibration. This method is intended to be a supplement to the displacement methods provided in Part 3, para. 5.1.1 when high accelerations are present.

Note that the limits resulting from this approach should be conservative, and exceeding these limits does not necessarily indicate that the allowable stresses of Part 3, section 3 have been exceeded (see also precautions below). For the vibration to pass these screening limits, the measured vibration must be below both the limits determined by the methods of Part 3, para. 5.1.1 and the criteria below. Alternatively more detailed testing and/or analysis can be used to demonstrate that the vibration stresses are below the limits of Part 3, section 3.

Significant vibrational stresses can occur when small branch piping (pipe sizes ≤2 in.) cantilevered to header piping is driven as a rigid body at a high acceleration. In these cases, allowable acceleration limits based on the allowable stress amplitudes of Part 3, section 3 can be used to evaluate the vibrational stresses. The acceleration limits discussed below provide a simplified method for quickly determining acceleration limits for these types of installations.

The equation for peak acceleration, α_A, limits in units of g is

$$\alpha_A = \frac{S_{\mathrm{el}} \times z}{\alpha \times C_2K_2 \times W_TL_E} \times \epsilon$$

where

C_2, K_2 = stress indices defined in Part 3, para. 3.2.1

L_E = a conservative value for the effective length in inches (meters) from the branch connection (at the location of the girth fillet weld) to the center of gravity of the masses that make up W_T

S_{el} = alternating stress from Part 3, para. 3.2.1

W_T = the total weight in pounds (kilograms) of all lumped masses including valves, fittings, flanges, the pipe itself, the pipe contents, and insulation

z = section modulus of branch pipe, in.^{3} (m^3)

α = stress reduction factor from Part 3, para. 3.2.1

ϵ = unit conversion factor equal to 1.0 when the U.S. Customary units specified below are used and equal to 10.197×10^{-4} when the metric units specified in parentheses are used

EXAMPLE APPLICATION: A peak stress index (C_2K_2 or $2i$) equal to 4.2, which corresponds to a girth fillet weld is incorporated into the acceleration limit equation. The acceleration limit equation should be changed accordingly when other values of C_2K_2 are applicable.

A ¾ in. Schedule 80 cantilevered branch line is accelerated by a header pipe at a peak acceleration of 1.0g (zero to peak). The branch line contains a 15-lb valve that is 6 in. from the branch connection. It is determined that $L_E = 6$ in. and $W_T = 16.6$ lb (see Fig. I-1 for determination of L_E and W_T). Determine if the measured acceleration falls within the simplified acceleration limit.

For carbon steels with a UTS ≤80 ksi, the equation for allowable acceleration in units of g is shown below. The equation below also assumes that $C_2K_2 = 4.2$.

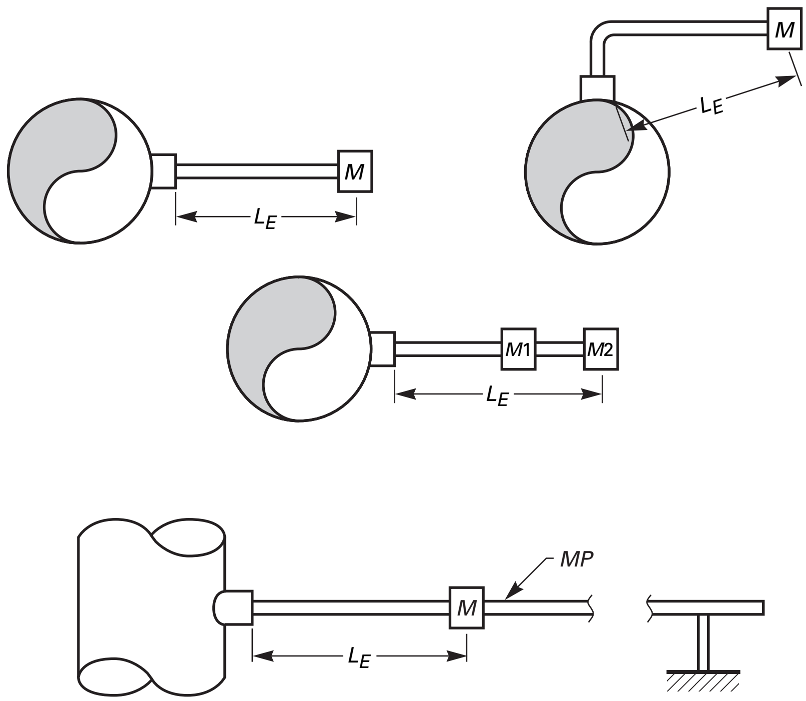
$$a_A = \frac{1{,}830z}{W_TL_E} = \frac{(1{,}830 \times 0.0853)}{(16.6 \times 6)} = 1.57\,g > 1.0\,g$$

The vibration is acceptable.

CAUTION: Acceleration measurements often result in large overall values especially if high-frequency accelerations are present. It is important to note that these high-frequency accelerations likely will not affect the piping as assumed by the criteria provided herein. The acceleration limit is based on the assumption that the dynamic accelerations affect the piping equivalent to static accelerations. Using this assumption for the high-frequency accelerations (where high frequency can be taken as frequencies above the fundamental frequency of the small branch line) may result in overly conservative results.

Some piping configurations and operating conditions, for example, instrument lines branching off process piping, can be excited in higher-order modes (i.e., one or more node points exist between the branch connection and the measurement location). This type of vibration is indicated by large accelerations occurring along with small displacements at locations several feet from the branch connection. In addition, local effects can result in high accelerations that are transmitted through the shell and do not affect the global structural vibration mode of the small branch piping. The criterion presented in this Nonmandatory Appendix is not applicable for this type of vibration; however, if used, the acceleration limit should be conservative. In general, more detailed analyses are required to evaluate the vibration.

Fig. I-1 Determination of L_E and W_T



where

W = weight of pipe within length L_E
W_C = weight of contents within length L_E
W_I = weight of insulation within length L_E
W_M, W_{M1}, W_{M2} = weight of concentrated masses (valves, fittings, flanges, etc.)
W_{MP} = weight of pipe, contents, and insulation outside length L_E to first rigid support or snubber in direction of vibration

Part 12
Loose Part Monitoring in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for loose part monitoring in light-water reactor (LWR) power plants. Loose part monitoring is required for the reactor vessel and primary coolant system in a pressurized water reactor (PWR) and the reactor recirculation system in a boiling-water reactor (BWR). This Part establishes monitoring methods, intervals, parameters to be measured and evaluated, and records requirements.

1.2 Overview

Loose part monitors (LPMs) provide a means for detecting and evaluating metallic loose parts through analysis of transient acoustic signals produced by loose part impacts. Installed systems use an array of externally mounted accelerometers located where loose parts are most likely to collect. Most systems include automatic annunciation (audible and visual) of a potential loose part, audio monitoring, and both automatic and manual signal recording.

High false alarm rates have been the major generic problem for LPMs and have reduced confidence in the information obtained from LPMs. The origins of false alarms are diverse and range from random variations in background noise levels to metallic impacts not caused by loose parts within the reactor coolant system. This Part, therefore, recommends that system sensitivity be set on the basis of background noise and to achieve the maximum sensitivity commensurate with an acceptable false alarm rate when the system has been installed in accordance with this Part.

Section 2 defines the terms used in this Part; because loose part monitoring is unique, some terms may deviate from definitions used in other Parts. Section 4 deals with loose part monitoring system instrumentation and its installation; it is intended that section 4 serve as the basis for the design and installation of new or replacement systems. Section 5 presents the basis for a comprehensive loose part monitoring program and is intended for use with all current and future systems.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

accelerometer: a transducer, typically piezoelectric, for converting acceleration to an electrostatic charge.

active channel: an LPM channel used by the alarm annunciator circuitry.

A/D: analog to digital.

ALARA: as low as reasonably achievable.

alarm condition: the LPM state indicating that the alert/alarm processor has detected characteristics indicative of a loose part.

alert/alarm processor: a device to process alert signals to discriminate between a valid loose part event and a false alarm.

alert level: a preestablished value against which the conditioned transducer signal level is compared to indicate the possibility of a loose part.

background noise: the combination of flow, structural, and electrical noise.

baseline: reference data used for system performance evaluation and signal analysis.

break frequency: the frequency at which the signal is attenuated by 3 dB relative to the passband.

BWR: boiling-water reactor.

calibration: a test during which known inputs are applied to a component and corresponding output readings are recorded to establish a baseline to compare with a previously established baseline or to adjust the component within specifications.

collection region: a region within the primary reactor coolant system in which loose parts tend to collect as a result of localized low flow rates or mechanical obstructions.

delay time: the difference in time required for the acoustic wave initiated by an impact to reach different loose part sensors.

dynamic range: the useful range of an electronic instrument over which the signal information is not compromised by instrument overload (distortion) or by electronic background noise.

electrical noise: any spurious electrical signal that contaminates the transmission, measurement, or recording of the desired signal.

false alarm: an alarm that occurs when there is no loose part; two types are addressed by this Part.

Type 1: a system alarm to a nonimpact signal, such as electrical noise.

Type 2: a system alarm to a metallic impact signal that is not a loose part.

field cable: the signal cable connecting the remote charge converter/preamplifier to the signal-conditioning and processing equipment.

field equipment: that portion of the installed LPM not in the control cabinet.

filter: a device for selecting signal components on the basis of their frequency. It allows components in one (or more) frequency band(s) to pass while attenuating components in other frequency bands.

flow noise: acoustic energy generated by the flow of coolant in the primary coolant system.

frequency domain: the characterization of a signal as a function of frequency.

g: the unit of acceleration due to gravity at the earth's surface, which for engineering purposes is 32.17 ft/sec^2 (9.81 m/s^2).

hardline cable: coaxial or triaxial cable with one or more metal sheaths insulated from the conductor by a mineral oxide; this type of cable is used to transmit the accelerometer signal to a charge conversion device in high temperature, humidity, and/or radiation environments.

impact energy: the kinetic energy of an impacting object.

impact test: a test to determine system functionality and response characteristics to a known metallic impact.

instrumented hammer: a hammer instrumented with a transducer to convert the hammer impact force or energy into an electrical signal.

IRIG: inter-range instrumentation group, a group establishing performance specifications for analog tape recording equipment.

loose part: two types are addressed.

captive: a constrained metallic part that can impact nearby components.

free: a metallic object that is disengaged and free to drift.

LPM: loose part monitor.

LWR: light-water reactor.

OTSG: once-through steam generator.

passive channel: an LPM channel that is not used by the alarm circuitry but that may readily be placed in service if needed.

power spectral density: the real-valued continuous function of frequency, presented with frequency on the horizontal axis and density on the vertical axis. The units of density are those of the data squared per unit of frequency; for example, for acceleration data in g the units would be g^2/Hz.

PSD: power spectral density.

PWR: pressurized water reactor.

RCP: reactor coolant pump.

RCS: reactor coolant system.

remote charge amplifier: a device that accepts the electrostatic charge output from a piezoelectric accelerometer and produces an amplified voltage output; these devices can accept a wider range of input resistance and capacitance than a remote charge converter/preamplifier and typically provide variable gain.

remote charge converter/preamplifier: a charge conversion device that accepts the electrostatic charge output from a piezoelectric accelerometer and provides a low impedance output signal for transmission to control room electronics.

resonance: the condition in which the natural frequency of a mechanical system is matched in frequency by an external vibration stimulus, resulting in higher vibration levels than would occur otherwise.

signal conditioner: a device that converts the signal transmitted from the remote charge converter/preamplifier to a form suitable for detection and recording; it may also provide electrical power to a remote charge converter.

signal-to-noise (S/N) ratio: the ratio of signal amplitude to noise amplitude.

slew rate: the maximum rate at which the output of an electrical device can change while operating within its linear range.

softline cable: coaxial or triaxial cable used to transmit the charge signal from an accelerometer to a charge conversion device; these cables, specially treated to minimize triboelectric noise, are flexible but less resistant to heat and radiation than hardline cables.

threshold detector: a circuit or device that monitors an LPM channel and provides an indication when the signal exceeds the alert level.

time domain: the characterization of a signal as a function of time.

triboelectric noise: the charge signal generated by movement of the signal cable.

white noise: a random signal characterized by constant spectral density independent of frequency.

3 REFERENCES

The following is a list of publications referenced or used in developing this Part.

ANSI S2.10-1971, American National Standard Medthods for Analysis and Presentation of Shock and Vibration Data

ANSI S2.11-1969, American National Standard for the Selection of Calibrations and Tests for Electrical Transducers Used for Monitoring Shock and Vibration

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036 (www.ansi.org)

Regulatory Guide 1.133, Revision 1, Loose Part Detection Program for the Primary System of Light-Water Cooled Reactors, U.S. Nuclear Regulatory Commission, 1981

Publisher: Superintendent of Documents, U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

4 EQUIPMENT

4.1 General

This section describes the major components of a loose part monitoring system: the sensor array and its cabling; the signal processing, detection, and data recording subsystems; analysis equipment; and documentation. Concern for personnel radiation exposure and safety has been included in developing system requirements.

Reactor coolant system background noise makes the detection of loose parts difficult because it masks the noise generated by loose part impacts; it is a composite of noise from sources such as coolant flow and mechanically and hydraulically generated vibration. Typically, background noise extends over a very wide frequency band but may have significant peaks in narrower frequency bands.

Waveforms from impacts near an accelerometer are significantly different in character than the background noise, as demonstrated in Fig. 1. However, impacts farther from the accelerometer (typified by the one shown in Fig. 2) are more difficult to detect because characteristics such as the impact shape become less distinct and the amplitude is decreased.

Impact signals contain significant information about the size of the impacting object and the impact force and energy. The general range of loose part impact signal amplitude and frequency content for masses between 0.5 lb and 30 lb (0.23 kg and 13.61 kg) is shown in Fig. 3. The composition and shape of both the component struck and the impacting object further affect the impact signal.

4.2 Field Equipment

This part of the system is composed of an externally mounted accelerometer, a sensor cable, a remote charge converter/preamplifier, and a field cable to the control cabinet electronics. Alternatively, a remote charge amplifier may be used instead of a remote charge converter/preamplifier. See Fig. 4 for details. Field components shall be selected to perform in the temperature/humidity/radiation environments normally expected at the chosen location.

4.2.1 Accelerometer. The general requirements for piezoelectric accelerometers are as follows:

(a) sensitivity: fixed, in the range 10 pC/g to 50 pC/g

(b) working range: 0.01 g to 100 g peak

(c) charge temperature response: less than ±15% from 60°F to 625°F (15.6°C to 329.4°C)

(d) radiation resistance: vendor tested for use in a nuclear environment

(e) operating temperature range: 60°F to 625°F (15.6°C to 329.4°C)

(f) frequency response: flat within −5% to ±10% from 5 Hz to 8 kHz, uniformly increasing response to the first resonance (first resonance greater than 20 kHz)

(g) electrical/mechanical: case isolated from signal ground (see para. 4.3.6)

(h) calibration: performed by the manufacturer or recognized test/calibration laboratory using a procedure that incorporates ANSI S2.11-1969

4.2.2 Accelerometer Mounting. There are two acceptable mounting methods.

(a) direct mounting: stud mount the accelerometer directly to the component as shown in Fig. 5.

(b) fixture mounting: stud mount the accelerometer to a mounting fixture attached to a component by mechanical means such as straps, clamps, or welds. Accelerometers may be mounted to bolts that are then inserted into existing threaded holes in primary coolant system components. Figure 6 shows one example of fixture mounting.

In no case shall accelerometers be magnetically mounted because of the poor frequency response obtained and the difficulty in maintaining a tight mechanical connection.

4.2.3 Accelerometer Installation. Installation of accelerometers shall conform to the following requirements:

(a) Use only the mounting studs provided by the accelerometer manufacturer or mounts fabricated to the manufacturer's specifications to preclude accelerometer damage and to ensure proper acoustic coupling.

(b) The manufacturer's recommendations for sensor installation shall be followed (including torque value).

(c) The mounting surface shall be finished to a surface roughness of 125 μin. (3.2 μm) rms or better.

(d) Acoustic couplants shall not be used because they degrade in the harsh environment.

(e) The mounting hole shall be perpendicular to the mounting surface within ±1 deg.

(f) Mounts shall be drilled and tapped so that the stud does not bottom in its hole.

(g) The threads shall be visually verified to be clean.

(h) Drilled-and-tapped or weldment mounts shall conform to ASME Code requirements.

Fig. 1 Typical Broadband Sensor Response to Nearby Impact

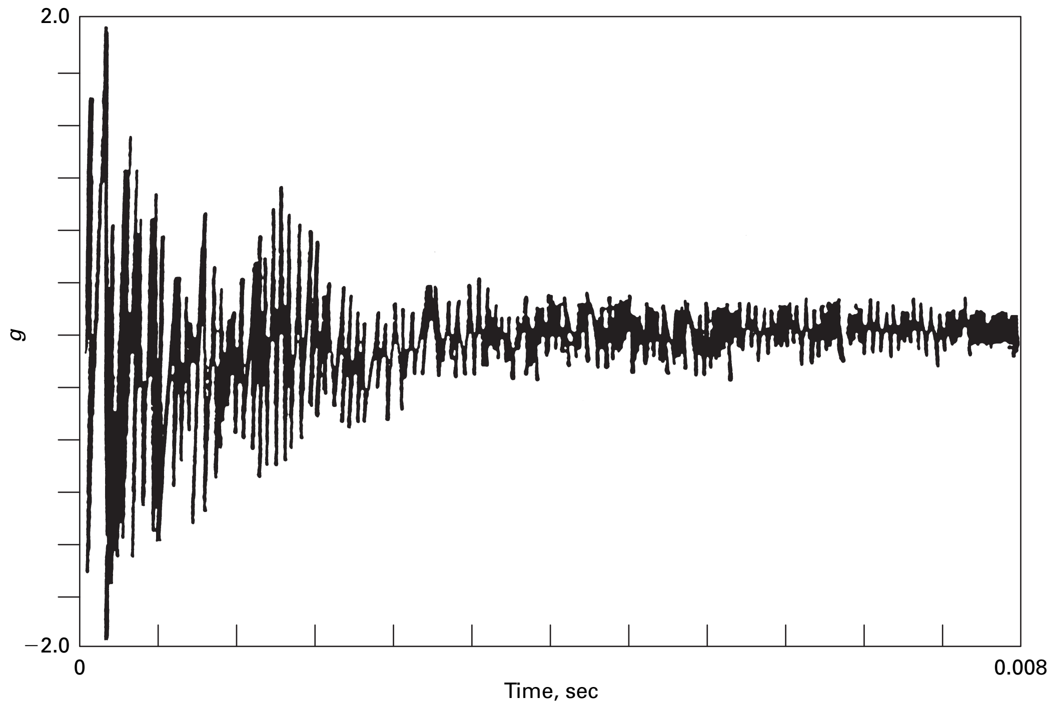


Fig. 2 Typical Broadband Sensor Response to More Distant Impact

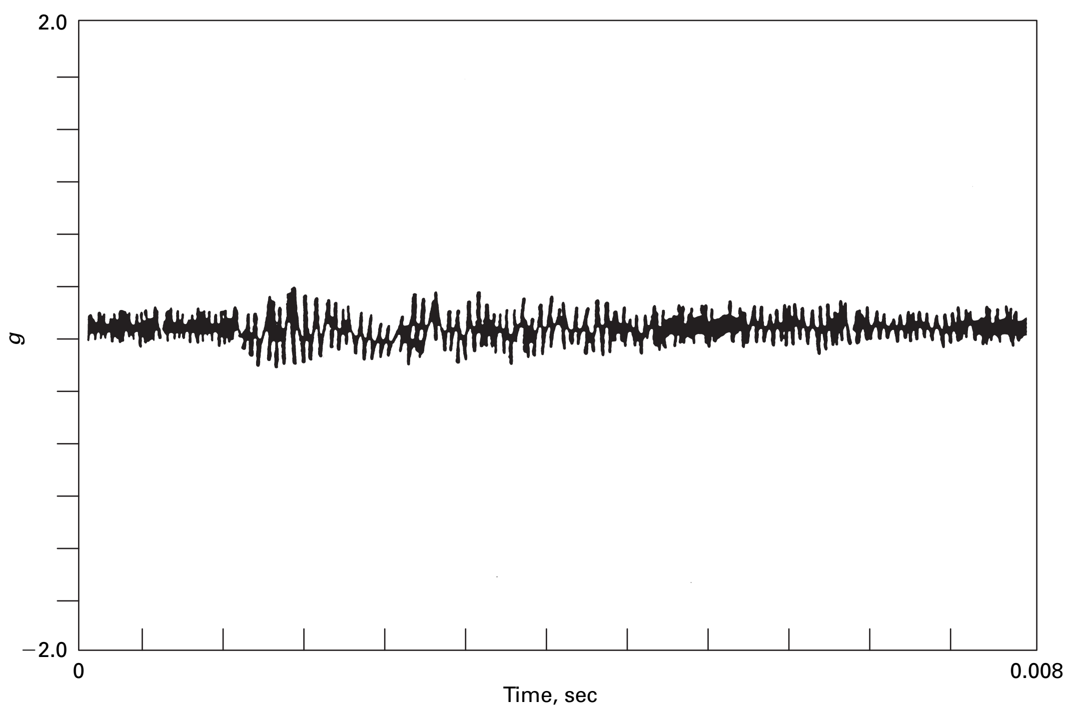


Fig. 3 Range of Loose Part Signal Amplitude and Predominant Frequency Content

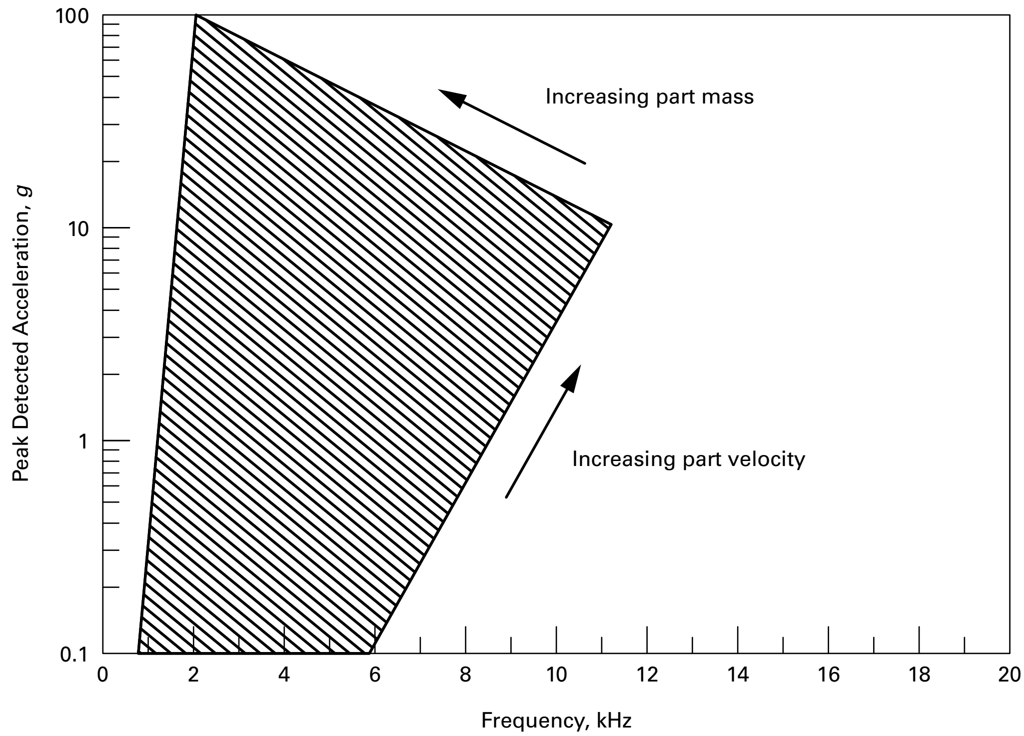
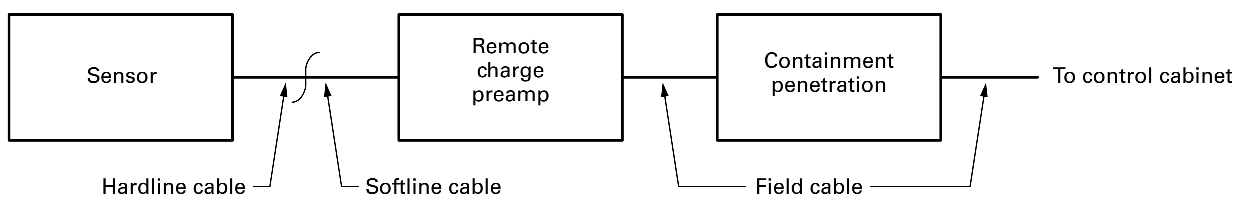
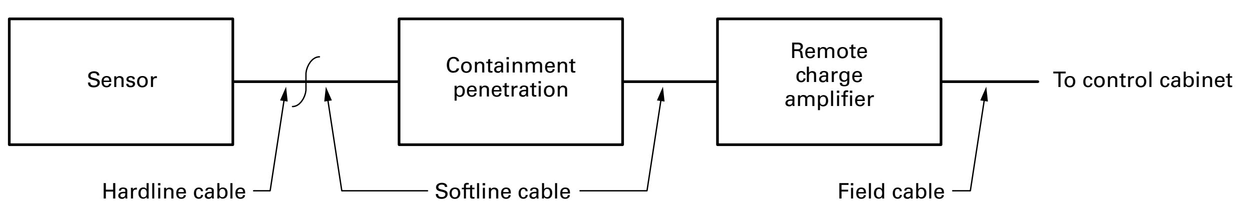


Fig. 4 Field Equipment



(a) For Remote Charge Preamplifier Inside Containment



(b) For Remote Charge Amplifier Outside Containment

Fig. 5 Direct Stud Mount

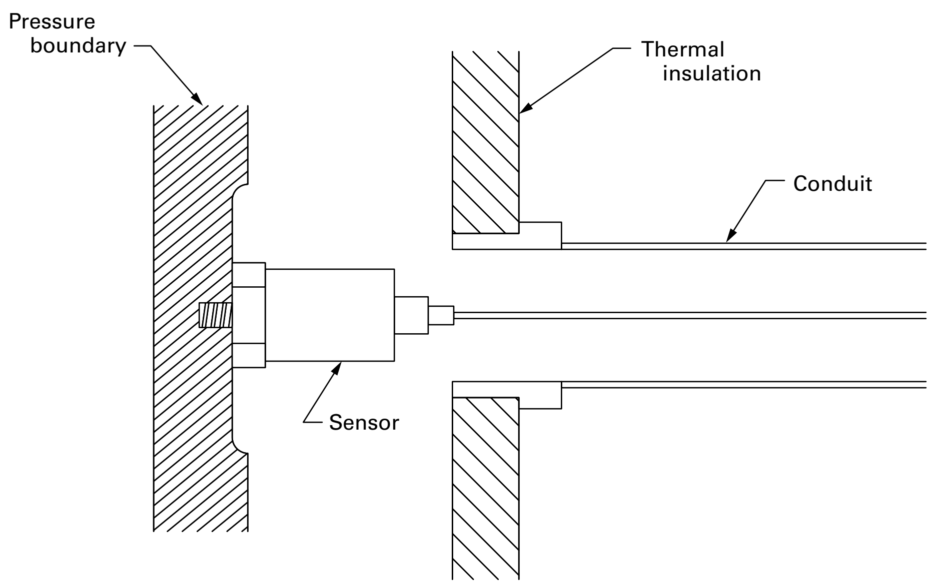


Fig. 6 Clamped Mount

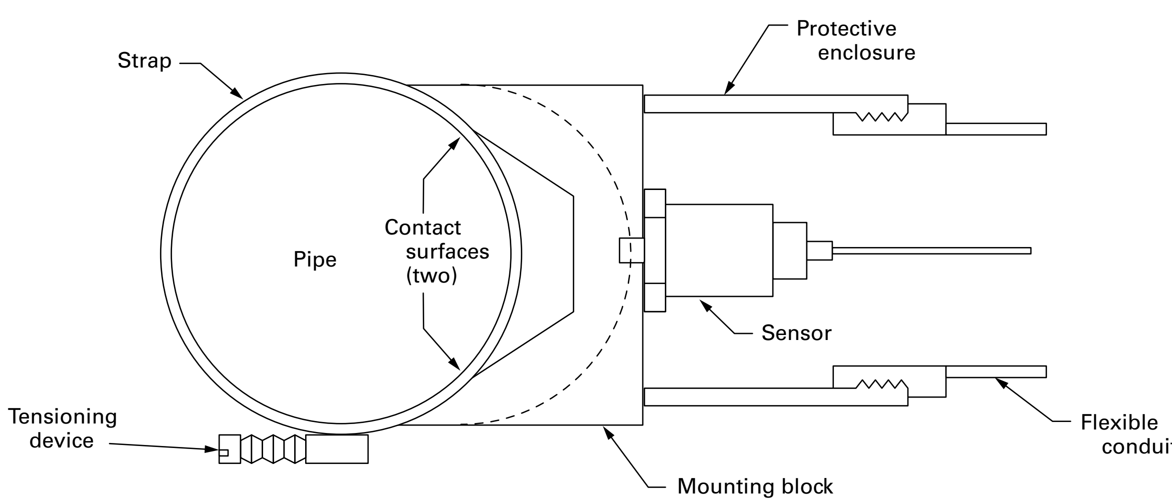


Table 1 Recommended PWR Accelerometer Locations

Location	Number of Sensors
Reactor vessel, upper	3
Reactor vessel, lower	3
Steam generator (each)	3
Reactor coolant pump (each)	1

(i) Clamped fixtures mounted on cylindrical surfaces shall have a two-line contact surface similar to that shown in Fig. 6.

(j) Mounts and fixtures shall be designed to compensate for thermal expansion so as to provide an approximately constant holding force throughout the operating temperature range.

(k) Sensors shall be protected from mechanical damage. Enclosures or covers of sufficient size for access and maintenance shall be used for accelerometers mounted external to mirror insulation. Mounting under mirror insulation without an additional enclosure is acceptable.

(l) Enclosures and conduit shall be acoustically isolated from the accelerometer and its mounting. Acceptable acoustic isolation may include a flexible conduit.

(m) The area in the vicinity of the sensor shall be inspected for loose metallic components (e.g., insulation, identification tags, and chains) that could impact on or near a sensor. All loose components shall be restrained.

4.2.4 Accelerometer Locations — PWR. In PWR applications, the recommended sensor locations for detection and analysis of metallic impact signals in the RCS are listed in Table 1. Care should be taken to select locations that are accessible from permanently installed ladders and platforms.

The three upper reactor vessel accelerometers shall be located at approximately 120-deg intervals around the top of the vessel or the reactor vessel head at an elevation no higher than the lifting lugs. Lifting lug mounting, if used, shall be such that it does not interfere with the lifting rod connected to the lug. The three lower reactor vessel accelerometers shall be mounted to the incore guide tubes within 18 in. (0.45 m) of the reactor vessel. The accelerometers should be approximately 120-deg apart and two-thirds the radial distance outward from the vessel axis. In plants without lower vessel incore guide tubes, the lower reactor vessel accelerometers shall be mounted to the reactor vessel.

For U-tube steam generators, mount one accelerometer above and one below the tube sheet in a vertical array on the primary inlet side. The third accelerometer shall be mounted on the shell near the top of the tube bundle. Figure 7 shows a typical sensor array for U-tube steam generators.

For OTSG, two accelerometers should be located near the upper tube sheet, approximately 180 deg apart, and one accelerometer should be located at the lower tube sheet. Figure 8 shows the recommended array for an OTSG.

Install one accelerometer on each reactor coolant pump. The sensor should be mounted to a lifting lug or other location on the pump bowl. The location should be selected to avoid sensor damage during pump maintenance.

4.2.5 Accelerometer Locations — BWR. For BWR applications, the recommended sensor locations are specified in Table 2.

Accelerometers mounted at the main steam outlet, feedwater inlet, and recirculation water outlet elevations shall be attached to convenient nozzles (such as instrument taps) as close to the vessel as possible. When possible, avoid pipes and lines with flow during operation. The locations selected shall have good acoustic coupling to the reactor vessel and should be equally spaced around the circumference. The three lower vessel accelerometers shall be mounted to the control rod drive housings as near the reactor vessel as practical; they should be approximately 120 deg apart and placed on peripheral drive housings. Figure 9 shows the recommended BWR sensor array.

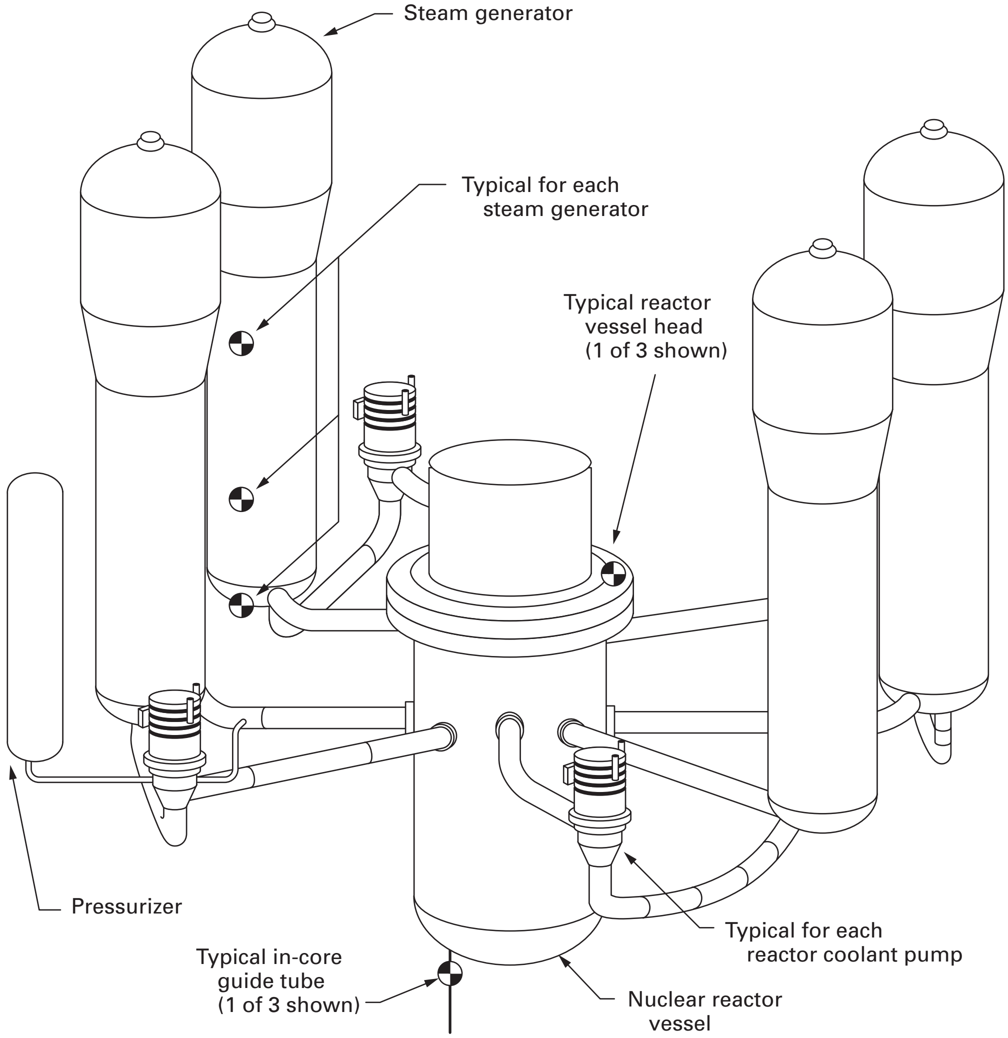
Install one accelerometer on each recirculation pump. The sensor should be mounted to a lifting lug or other location on the pump bowl. The location should be selected to avoid sensor damage during pump maintenance. Install one accelerometer on each recirculation loop discharge pipe near the recirculation header.

4.2.6 Sensor Cable. The cable between the sensor and the remote charge converter/preamplifier or remote charge amplifier shall be of a type designed for use with low level charge signals generated by accelerometers. Low noise, hardline cable is required under thermal insulation covering components and piping. High temperature, low noise softline cable may be used outside this region when the temperature is less than 400°F (204°C). Hardline cable lengths greater than 20 ft (6.1 m) are discouraged. Connection locations should permit access for inspection and maintenance.

The sensor cable shall be completely enclosed in conduit. To prevent ground loops and to provide additional acoustic isolation, the hardline cable sheath and intermediate connectors shall be insulated with temperature- and radiation-resistant material to avoid contact with the conduit. Triaxial hardline cable affords additional protection against ground loops. Protection against chafing of the cable and insulation at the conduit exit points is required.

4.2.7 Remote Charge Converter/Preamplifier. The remote charge converter shall be located as close as possible to the accelerometer without surpassing the temperature and radiation limitations (including radiation from withdrawn incore detectors). The converter

Fig. 7 Recommended Sensor Array for PWR With U-Tube Steam Generator



GENERAL NOTE: ◐ = LPM sensor

Fig. 8 Recommended Sensor Array for PWR With Once-Through Steam Generator

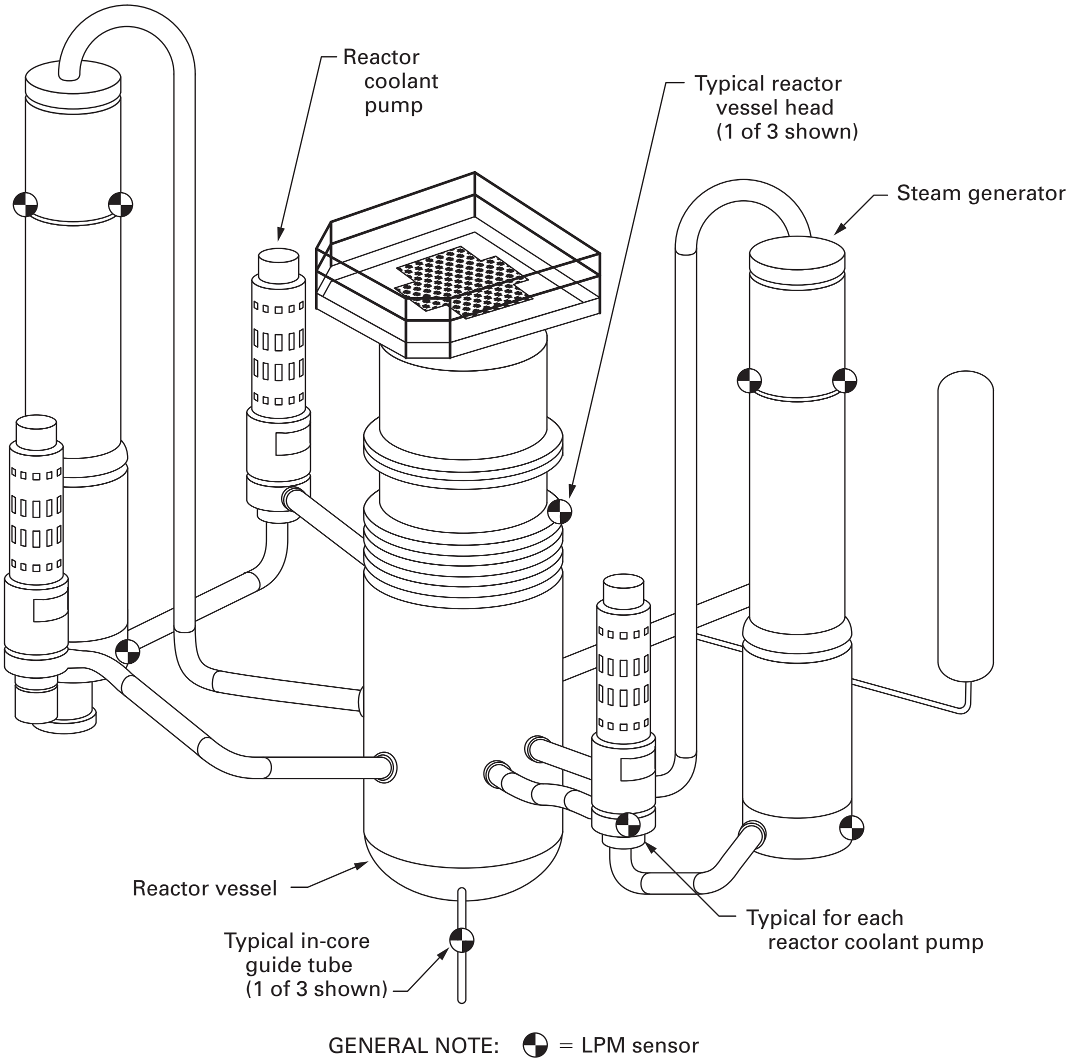
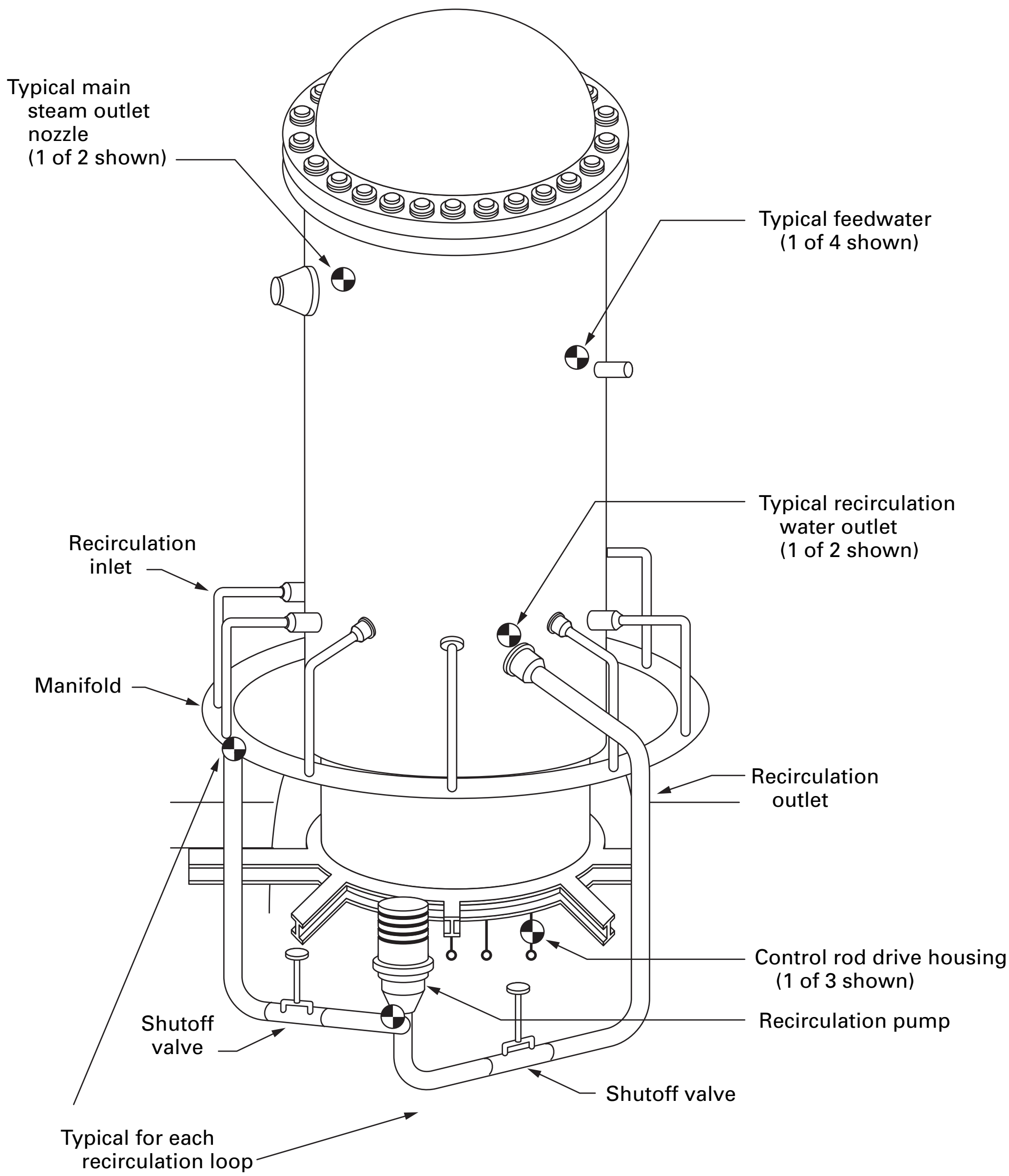


Table 2 Recommended BWR Accelerometer Locations

Location	Number of Sensors
Main steam outlet elevation	2
Feedwater inlet elevation	4
Recirculation water outlet elevation	2
Recirculation pump (each)	1
Recirculation discharge pipe (each)	1
Reactor vessel bottom	3

Fig. 9 Recommended Sensor Array for BWR



GENERAL NOTE: ⊕ = LPM sensor

shall be mounted inside a junction box to provide physical protection. Safe personnel access to the junction boxes from permanently installed ladders and platforms shall be provided. Remote charge converters shall meet the following requirements:

(a) operational temperature: 60°F to 212°F (15.6°C to 100°C)

(b) gain: fixed, in the range 1 mV/pC to 10 mV/pC

(c) radiation resistance: vendor tested for use in a nuclear environment

(d) frequency response: flat within ±5% from 5 kHz to 20 kHz

(e) input resistance and capacitance: compatible with combined accelerometer/sensor cable values at maximum operating temperature

(f) input range: charge equivalent to at least 100 *g* peak without overload

(g) electrical: installed so that both the signal and reference are isolated from ground

(h) output: capable of driving the combined field cabling and control cabinet electronics load at a signal level of 100 *g* peak and 20 kHz without amplitude or slew-rate limiting

4.2.8 Remote Charge Amplifier. Remote charge amplifiers may be used outside containment and shall not be used in containment unless they meet the environmental requirements for remote charge converters. Remote charge amplifiers shall meet the following requirements:

(a) operational temperature: 60°F to 130°F (15.6°C to 54.4°C if used outside containment)

(b) gain: selectable, in the range 1 mV/pC to 10 mV/pC

(c) frequency response: flat within ±5% from 5 kHz to 20 kHz

(d) input resistance and capacitance: compatible with combined accelerometer/sensor cable values at maximum operating temperature

(e) input range: charge equivalent to at least 100 *g* peak without overload

(f) electrical: installed so that both the signal and reference are isolated from ground

(g) output: capable of driving the combined field cabling and control cabinet electronic load at a signal level of 100 *g* peak and 20 kHz without amplitude or slew-rate limiting

4.3 Control Cabinet Equipment

4.3.1 Signal Conditioner. The signal conditioner shall incorporate the following features:

(a) Frequency response: flat within ±5% from 5 kHz to 20 kHz.

(b) Filters: 18 dB/octave or greater attenuation rate with minimum stop band rejection of at least 60 dB. Filters may be either fixed or selectable with the suggested high-pass break frequency between 500 Hz and 2 kHz and the low-pass between 8 kHz and 12 kHz.

(c) Test connector providing unfiltered or selectable filtered/unfiltered signal for analysis and recording.

(d) Dynamic range: signal level equivalent to at least 100 g peak in the least-sensitive range.

(e) Output shall be calibrated in units of *g*/V.

(f) Over-range and under-range indication (unless provided in either the detector or discriminator circuitry) or signal level indication.

(g) Convenient measurement of remote charge converter/preamplifier bias voltage or current.

(h) Convenient indication of gain or range if externally adjustable.

(i) Electrical compatibility with accelerometer and charge converter.

(j) External controls affecting calibration and alarm setpoints shall be designed to prevent inadvertent movement.

4.3.2 Threshold Detector

(a) Each channel shall have a separate threshold adjustment.

(b) Detector may use either absolute or variable level detection techniques.

(c) Variable alert levels shall be proportional to the magnitude of the band-limited background.

4.3.3 Alert/Alarm Processor

(a) Rejects alert patterns not meeting preestablished criteria.

(b) Automatic alert reset if alarm criteria are not met.

(c) Visually indicates channel(s) in an alert condition.

(d) Indication of the first channel to alert.

(e) Audibly indicates that the system is in the alarm state.

(f) Manual alarm reset in the control cabinet.

(g) Automatic initiation of data recording or storage when the alarm condition is entered.

(h) Alarm indication to the plant annunciation/computer system; the alarm shall be annunciated in the control room on a unique (nonganged) alarm.

4.3.4 Recorder. The system shall be capable of automatically recording the initiating event and for 2 min to 5 min after the event. The filtered signal shall be stored in a format such that it can be electronically reproduced for further analysis. It may be necessary to use both a transient recording device to capture the initial event and a second device for continuous recording. The continuous recording device may be either analog or digital.

(a) Transient Recorder

(1) trigger data storage on alarm

(2) pretriggering to ensure capture of entire waveform

(3) data storage shall continue until the continuous recorder is operating

(4) 50 kHz sampling rate per channel (minimum)

(5) 12 bit A/D converter (minimum)

(6) simultaneous recording of all signal channels required in para. 4.2.4 or 4.2.5

(b) Continuous Analog Recorder

(1) frequency response: flat within ±5% from 1 kHz to 10 kHz, recommended to be flat within ±10% from 1 Hz to 20 kHz (additional specification)

(2) simultaneous and continuous recording (for at least 2 min) of the channels required by para. 4.2.4 or 4.2.5

(3) recorder configured to IRIG standards

(4) recording of a time code providing date and time to the nearest second

(c) Continuous Digital Waveform Recording

(1) simultaneous and continuous recording (for at least 2 min) of the channels required by para. 4.2.4 or 4.2.5

(2) 50 kHz sampling rate per channel (minimum)

(3) 12 bit A/D converter (minimum)

(4) recording of a time code providing date and time to the nearest second

4.3.5 Audio Monitor. The audio monitor shall incorporate the following features:

(a) amplifier frequency response: flat within ±1 dB from 30 Hz to 15 kHz

(b) headphone output

(c) speaker frequency response: rated response from 100 Hz to 15 kHz

(d) switching capability to permit audio monitoring of any LPM channel or previously recorded channel

(e) inputs shall be selectable to permit use of either the signal conditioner unfiltered output or a normally filtered output

(f) volume control independent of signal conditioner gain

4.3.6 Cabling and Grounding. The LPM shall be designed to provide adequate signal shielding and to avoid ground loops. For systems using single-ended remote charge converters/preamplifiers, the system shall be installed with a single point ground at the control cabinet. The accelerometer, sensor cable, remote charge preamplifier, and field cabling shall be electrically isolated from building or safety grounds.

The field cabling shall be twisted–shielded pair-type or triaxial-type cable. The shield shall be electrically isolated from both the signal and signal reference leads and shall be grounded in the signal cabinet. Signal and shield integrity shall be maintained through penetrations, and only instrument-quality, low-level signal penetrations shall be used. Channels monitoring a single collection region shall be routed separately to minimize common-mode failure. Fiber optic cable may be used in appropriate environments.

4.4 Analysis and Diagnostic Equipment

4.4.1 General. The instrumentation needed to perform the various analyses described in this Part include a data recorder, a digital oscilloscope (or similar instrument to capture transient waveforms), a frequency analyzer, and a printer/plotter to supply a hard copy of analyzed data. Multifunction instruments that perform one or more of these functions may be used in lieu of individual instruments. This instrumentation can be included in the control cabinet electronics and may be used for diagnostics if analysis does not require removing the LPM from service.

4.4.2 Data Reproducer. Separate data reproduction equipment compatible with para. 4.3.4 shall be available for diagnostic analysis if the control cabinet recorder(s) cannot be used for diagnostics without compromising the LPM detection and alarm functions.

4.4.3 Waveform Analyzer. The waveform analyzer shall have

(a) minimum of two channels

(b) variable sampling rate, with a maximum sampling rate no less than 50 kHz per channel

(c) capability to store and display waveforms containing no less than 4,000 points per channel

(d) capability to store and display captured transient waveforms in adjustable time spans from at least 10 to 40 ms

(e) pre- and post-trigger capture feature

(f) 12 bit or higher A/D converter resolution

(g) ability to trigger on selected channel or on external trigger

(h) adjustable trigger threshold

4.4.4 Frequency Analyzer. The frequency analyzer shall have

(a) frequency range: 0 kHz to 25 kHz, min.

(b) 12 bit or higher A/D converter resolution

(c) summation averaging selectable in steps up to at least 256 samples per average

(d) minimum resolution of 256 points in the frequency domain or zoom capability with 1 Hz resolution

(e) automatic indication and selectable rejection of overload signals

(f) ability to store frequency domain results for comparison to other data

(g) ability to process nonzero mean time value signals

4.4.5 Hard Copy. A printer or plotter that is capable of producing annotated hard copy information from the time and frequency domain analysis equipment.

5 PROGRAM ELEMENTS

5.1 General

This section is intended to assist nuclear utilities in implementing a program to detect and diagnose loose parts.

5.2 ALARA

An LPM program will require occasional work in radiation areas. Those activities should be closely coordinated with plant ALARA programs. In particular, the following should be implemented:

(a) Equipment used in the LPM should be reliable to minimize the need for maintenance.

(b) LPM containment components should be easily replaceable to minimize exposure time during maintenance.

(c) LPM components should be accessible from permanent ladders and platforms to reduce personnel time in containment.

(d) Charge converters/preamplifiers should be mounted in locations that serve to reduce personnel exposure and to increase equipment reliability.

(e) Maintenance and calibration should be planned and, if necessary, practiced outside containment to minimize personnel time in containment.

(f) Test and replacement equipment should be checked carefully for operability prior to entry into containment.

5.3 Precautions

High voltages may be encountered during procedures specified in this section; therefore, care must be taken to protect both personnel and equipment from shock hazards and electrostatic shock damage. Accelerometer signal leads or cables attached to accelerometers should be shunted to ground before connection to other equipment. Personnel preparing specific procedures based on this Part shall ensure that voltages produced by impedance-measuring devices will not damage the components under test.

5.4 Calibration

5.4.1 Initial Installation. Initial calibration of the LPM electronics shall be performed prior to baseline testing.

(a) Control Cabinet Electronics. Perform vendor-recommended calibration.

(b) Charge Converter/Preamplifier. Prior to installation, verify the conversion ratio (mV/pC) and determine the frequency response (over the range of 5 Hz to 20 kHz) using a simulated charge input. The block diagram is presented in Fig. 10.

(c) Sensor Cable. Measure the open-circuit resistance and capacitance of the sensor cable (consult the cable vendor for the correct procedure).

(d) Sensor

(1) Verify sensor frequency response, amplitude linearity, and sensitivity. Test instrument system accuracy shall be ±5%. Sensor excitation may consist of either a continuous frequency sweep at a single acceleration value or discrete frequencies at a minimum of seven points distributed over the sensor response range. Sensitivity shall be verified at one or more of the manufacturer's calibration frequencies (typically 100 Hz, 5 kHz, or 10 kHz). Amplitude linearity shall be determined by measuring at 0.1 g and 10 g at approximately 5 kHz. It is recommended that the method used be in accordance with ANSI S2.11-1969.

(2) Measure the resistance and capacitance of the sensor. To prevent component damage, consult the sensor vendor for the correct procedure.

(3) If an accelerometer is dropped or physically damaged, do not use it until it is retested by the continuous sweep method and verified to be undamaged.

(4) After the sensor and cabling to the charge converter/preamplifier have been installed, measure the resistance and capacitance of the sensor/sensor cable combination at the input to the charge converter.

(5) Once installed, never remove the sensor except for replacement. Sensors shall not be replaced routinely.

(e) Field Cabling. With the field cabling disconnected at the control cabinet and at the remote charge converter/preamplifier, measure the cable properties (typical for twisted–shielded pair cable) shown in Fig. 11.

Do not use more than 50 V in determining resistance. Use either a bridge-type instrument or capacitance meter verified to be accurate for measuring capacitance in long cables.

5.4.2 Replacement. Perform the appropriate preinstallation and impact tests for any repaired or replaced component. The impact location(s) shall be consistent with the requirements set forth in para. 5.5.3 of this Part. A single mass in the 3 lb to 5 lb (1.4 kg to 2.3 kg) range as specified in para. 5.5.4 is recommended.

5.5 Baseline Impact Testing

5.5.1 General. Data acquired in the baseline test program are used in the analysis and diagnosis of anomalous noise in the reactor system. The baseline test program should be implemented prior to initial LPM operation, and is required after changeout of any component upon which an LPM sensor is mounted.

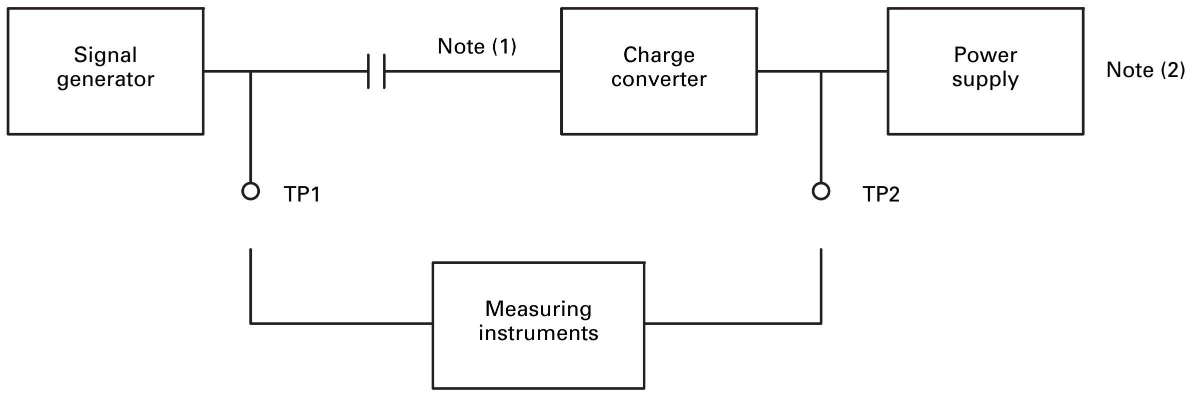
The purpose of impact testing is

(a) to determine system sensitivity to impacts of known energy or force at known locations

(b) to characterize transducer response to impacts from objects of different masses at known locations

(c) to verify the capability to discriminate primary-versus secondary-side impacts in steam generators and the capability to determine the approximate impact location in the reactor coolant system

Fig. 10 Block Diagram for Charge Converter Calibration Tests



NOTES:
(1) 1,000 pF typical; consult charge converter vendor for specifics.
(2) Use LPM signal conditioner if possible.

The impact amplitude shall be calculated using the test weight mass and distance through which it falls if a pendulum/drop method is used. The impact amplitude can be measured electronically when using an instrumented hammer as the stimulus.

5.5.2 Plant Conditions. Impact testing should be performed during cold shutdown; calibration at higher temperatures is discouraged for safety reasons. Reactor coolant system water levels should be as close to normal operating levels as possible.

5.5.3 Impact Locations. At least two impact test locations shall be selected and documented for each natural collection region and the secondary side of each steam generator. The impact locations shall not be within 3 ft (0.91 m) of any sensor. Since one impact point in each collection region (except the reactor vessel bottom) is intended to be used for periodic impact testing, ease of access shall be considered.

5.5.4 Test Weights/Hammer Masses. A range of test weights should be used to define channel response over the monitored frequency band (refer to Fig. 3). Recommended weights for the ball or hammer are 0.5 lb to 1.0 lb, 3 lb to 5 lb, and 10 lb to 20 lb (0.23 kg to 0.45 kg, 1.4 kg to 2.3 kg, and 4.5 kg to 9.0 kg, respectively). For each test weight at least three impact amplitudes should be used. To prevent or minimize surface marring, the test weights and hammer tips should be fabricated from metal slightly softer than the surface to be struck.

5.5.5 Impact Test Analysis. Impact test data shall be reduced and analyzed at the completion of the test data acquisition program. The purpose of this analysis is to determine the response to known metallic impacts and to provide reduced reference data for use in diagnostics.

(a) Normalized response outputs shall be provided in one or more of the following frequency domain formats:

(1) force hammer: frequency response function displaying the ratio of acceleration (response) to force (input).

(2) ball: auto spectral plots of each sensor response.

A digital Fourier transform method shall be used to calculate the spectrum. Appropriate transform block lengths or an exponential weighting function shall be used to ensure that the amplitude of the signal at the end of the transform data block is less than 10% of the peak amplitude.

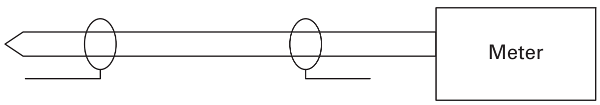
The analysis results should be in engineering units. The preferred engineering units for spectral plots are g^2/Hz or $g/\text{Hz}^{1/2}$ and for the frequency response function are g/lb. The preferred units for PSD are g^2/Hz. Some PSD systems may also use units of $g/\text{Hz}^{1/2}$.

(b) The delay times between the wave arrival at different sensor locations should be measured for all channels. The measurements should be relative either to the sensor closest to the impact point or to the instrumented hammer.

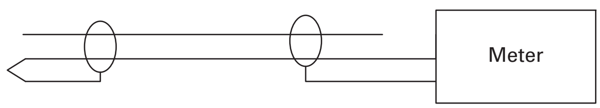
(c) The primary signal frequency content should be identified for impacts generated by each mass, and sensor mounted and crystal resonances should be identified for each sensor. The analysis displays shall extend to less than 10 Hz.

Each LPM channel peak response shall be measured for every impact. The corresponding peak input level shall also be documented for each impact. Peak amplitudes for multiple impacts at a single test condition should be averaged. The average, high, and low values for each sensor and test condition should be documented.

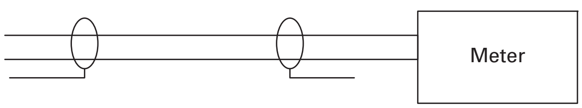
Fig. 11 Cable Properties
(Typical for Twisted–Shielded Pair Cable)



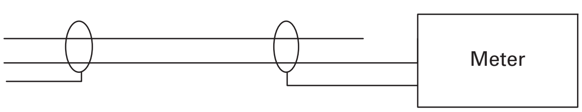
(a) Signal Pair Loop Resistance
(Typical <20 Ω)



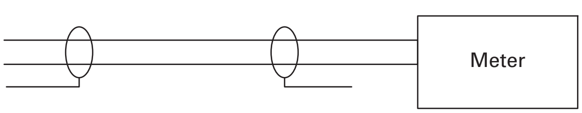
(b) Conductor-to-Shield Loop Resistance
(Typical <20 Ω)



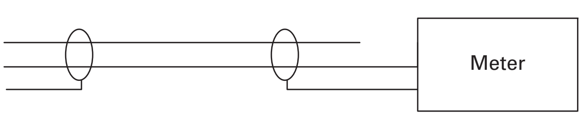
(c) Conductor-to-Conductor Resistance
(Typical >200 Ω)



(d) Conductor-to-Shield Resistance
(Typical >200 Ω)



(e) Conductor-to-Conductor Capacitance
(Derive From Vendor Data)



(f) Conductor-to-Shield Capacitance
(Derive From Vendor Data)

Prior to performing time domain analysis, low-pass filter the signal to reduce the effect of the sensor resonances. Time domain plots should be displayed with time on the horizontal axis and signal magnitude on the vertical axis. The signal magnitude shall be plotted in *g* units, although units of volts are acceptable if the waveform analyzer cannot perform engineering unit conversions (in this case, the relationship between voltage and acceleration shall be noted on the plot).

5.6 Initial LPM Setpoints

At the onset of initial RCS flow and as heatup progresses, verify that the LPM channels are operable. This may be done by measurement and trending of RMS values and identification (and documentation) of major structural resonance characteristics.

In the event of prolonged reactor startup or reduced power operation, the LPM setpoints should be optimized as conditions warrant. Within 2 weeks after reaching full-power operation, a review of the major reactor coolant system background noise should be complete. At that time, LPM systems having adjustable bandpass filters shall be adjusted for optimum noise rejection in each channel. The low-pass break frequency should not be less than 8 kHz nor the high-pass greater than 2 kHz, except as necessary to reject interfering background noises having an adverse effect on sensitivity or false alarm rates; but, in no case shall the bandpass be reduced to less than 5 kHz. Systems with fixed high- and low-pass filters should use 1 kHz and 10 kHz as the respective high- and low-pass break frequencies. The final filter settings shall be included in the system documentation package.

Both absolute and variable (floating) threshold detector alert levels shall be set initially to three times the long-term, band-limited background noise level at power operation to 1 *g* or to the manufacturer's recommendation. Individual channel threshold levels (setpoints) shall be adjusted after reaching power operation so that the system false alarm rate caused by Type 2 false alarms is approximately one event every 2 weeks. After establishing the rate, verify that the threshold levels necessary to achieve the rate are not so high as to compromise sensitivity to potentially damaging loose parts. For floating systems, this may be accomplished by ensuring that the effective threshold setpoint (background level multiplied by the floating threshold ratio) does not exceed 1 *g*. If the setpoint exceeds 1 *g*, the system installation and/or the reason for excessive variation in the background noise should be investigated and corrective action taken.

5.7 Heat-Up and Cool-Down Monitoring

During plant heat-up and cool-down, RCS noises different from those during normal operation will be present. It is also a period of time during which the probability of a loose part is greater than normal. Therefore, during plant transient operation it is recommended that the following actions be considered:

(a) Audibly monitor noises during RCP starts and stops.

(b) Record data during the first RCP start, first shutdown, and last shutdown of a cycle.

(c) Monitor each shift in accordance with para. 5.8.2.

5.8 Periodic Monitoring and Testing

Periodic monitoring of the RCS is an integral part of an effective loose part program; periodic testing of an LPM provides the basis for determining system operability. Both shall be performed on a shift, week, quarter, and fuel cycle basis. System parameters measured or observed during each test shall be documented on a data sheet and included in the system documentation. If during periodic testing the LPM or any LPM channel is determined or suspected to be inoperable, corrective action shall be initiated.

5.8.1 Startup. Background from each sensor shall be recorded during initial startup of the system using installed system recording capability. The data shall be maintained in a retrievable format (e.g., disk, magnetic tape). It is recommended that monitoring and recording be done both during hot standby and within 100 hr of reaching full-power operation.

5.8.2 Each Shift. With initiation of reactor coolant flow, perform the following:

(a) Verify that the LPM power is on.

(b) Verify that the LPM is in a ready condition (e.g., recorder autostart enabled and inhibits off).

(c) Monitor sound from all active sensors. Each channel should be monitored for at least 30 sec. Noise considered to be anomalous should be documented and evaluated.

5.8.3 Each Week. With the reactor in hot standby or power operation, perform the following:

(a) Identify and document the channels that are being actively monitored.

(b) Monitor sound from all active sensors. Each channel should be monitored for approximately 30 sec. Noise considered to be anomalous should be documented and evaluated.

(c) Document the status of user controllable setpoints (e.g., gains and filters) and verify that the switch settings are as intended.

(d) Measure and document the background level of each active channel using front panel test points or meters, if provided.

(e) Perform vendor recommended self-test of the LPM automatic alert and alarm circuitry.

5.8.4 Each Quarter. With the reactor in hot standby or power operation and with all reactor coolant pumps running, do the following:

(a) Perform the weekly test for all channels, both active and passive (if present).

(b) Record background from each sensor shall be recorded for trend analysis as specified in para. 5.8.5. The data should be maintained in a retrievable format (e.g., disk, magnetic tape).

(c) Compare spectra from each channel with data from the two preceding quarterly functional tests. The comparison should include spectral response in the range of the RCP blade-passing frequency, known structural resonances, broadband flow noise, and accelerometer-mounted resonance.

(d) Verify the performance of the installed LPM recorder(s).

(e) Measure and document the voltage or current supplied to each remote charge converter. Adjust the voltage or current supply if recommended by the vendor and document any changes made.

5.8.5 Each Fuel Cycle

(a) At each refueling outage, any degradation of LPM components shall be evaluated and documented. The evaluation should be based on the following:

(1) trends in charge converter supply voltage or current

(2) variations in the quarterly spectral data that may be indicative of change in the overall response of a channel

(3) the performance of vendor-recommended calibration of LPM control cabinet electronics

Changes in spectral characteristics or trend information shall be evaluated and documented. Unexplained deviations shall be formally evaluated and corrective action taken if appropriate.

(b) As an outage item to be performed immediately prior to heatup, validate the operability of each channel by performing an impact test(s). The impact location(s) shall be consistent with the requirements set forth in para. 5.5.3. A single mass in the 3 lb to 5 lb (1.4 kg to 2.3 kg) range as specified in para. 5.5.4 is recommended.

5.9 Alarm Response and Diagnostics

5.9.1 General. Actions should be taken to determine if the alarm has been caused by an actual loose part and what the damage potential may be. Data in the form of plots, graphs, and amplitudes should be labeled and scaled in units consistent with those in para. 5.5.5.

5.9.2 Alarm Response. Plant procedures shall require operator response to all LPM alarms. Initial alarm response shall include the following:

(a) Verify that automatic data recording was initiated.

(b) Identify and document the unit/channel(s) alarming.

(c) Reset the LPM.

(d) Listen to all channels.

(e) If the alarm cannot be reset or recurs within 5 min, notify the shift supervisor.

(f) Log the signal conditioner gain or range for the signals recorded if not provided automatically by the system.

(g) Note the time of day, the plant condition, and any significant plant operating changes that occurred before the alarm.

5.9.3 Diagnostics. LPM alarms that are indicative of metallic impacting shall be further evaluated by appropriate personnel. The objectives of diagnostic evaluation are to

(a) verify LPM channel operability

(b) estimate the location of the metallic impact based on consideration of delay time, amplitude, and wave shape

(c) estimate impact energy based on initial impact test data

(d) estimate impact mass based on the baseline test data and measured signal properties including amplitude and frequency content

(e) review plant process data for anomalous behavior

(f) review diagnostic results with plant operation personnel

5.9.4 Background Changes and Setpoint Adjustments. Alarm diagnostics may indicate a change in plant background characteristics rather than the presence of a loose part. When this process occurs, the LPM alarm rate may in time increase to an unacceptable level. Adjustments are permitted, but the threshold shall not be increased without investigating the reason for the change in the background. Any change in setpoints shall be entered in the system documentation.

6 DOCUMENTATION

The LPM operator shall maintain system documentation containing accurate and complete information pertinent to the system, its calibration, and any other information that would affect measurements, judgments, and calculations made during data analysis. The documentation shall also include the information necessary to quickly locate a particular sensor, charge converter, or cable junction for maintenance, calibration, or diagnostics. As a minimum, the following shall be included:

(a) vendor manuals and calibration data.

(b) as-built field drawings. Electrical drawings shall include cabling and conduit drawings detailing penetrations, conduit routing, and junction box locations. Mechanical drawings shall include sensor locations, sensor mount fabrication drawings, and charge converter/preamplifier locations.

(c) installed (in-containment) component identification to include the device model and serial numbers and types and lengths of cable used between the accelerometer and the charge converter.

(d) complete photographic documentation of the sensor and charge converter installation (ALARA and safety considerations may preclude this requirement in some existing systems).

(e) the results of and procedures for all tests required by this document.

Part 12, Nonmandatory Appendix A
References

ANSI S2.10-1971, American National Standard Methods for Analysis and Presentation of Shock and Vibration Data

ANSI S2.11-1969, American National Standard for the Selection of Calibrations and Tests for Electrical Transducers Used for Monitoring Shock and Vibration

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036 (www.ansi.org)

NP-5743, Loose Part Monitoring System Improvements; Research Project 2642-1; C. W. Mayo, D. P. Bozarth, G. N. Lagerberg, C. L. Mason; 1987

Publisher: Electric Power Research Institute (EPRI), 3420 Hillview Avenue, Palo Alto, CA 94304 (www.epri.com)

Regulatory Guide 1.133, Loose Part Detection Program for the Primary System of Light-Water Cooled Reactors, Revision 1, 1981

NUREG/CR-4577, Loose Part Monitoring Programs and Recent Operational Experience in Selected U.S. and Western European Commercial Nuclear Power Stations, R. C. Kryter, 1984

Publisher: U.S. Nuclear Regulatory Commission (NRC), 11555 Rockville Pike, Rockville, MD 20852 (www.nrc.gov)

Part 16 Performance Testing and Monitoring of Standby Diesel Generator Systems in Light-Water Reactor Power Plants

(15)

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for inservice testing and inspection to assess the operational readiness of certain diesel drive assemblies used in light-water reactor (LWR) power plants. The diesel drive assemblies covered are those required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident. This Part establishes inspection requirements, parameters to be measured and evaluated, and record requirements.

1.2 Purpose

This Part provides guidance on the performance of periodic testing to demonstrate the operational readiness of a standby diesel generator.[1] In addition, material condition monitoring methodologies, e.g., engine component operating parameters trending, engine analysis, vibration analysis, lube oil analysis, fuel oil analysis, cooling water analysis, and thermography, should also be considered for assessing the health of the diesel generator system. Since all diesel generator systems are not identical in design, there may be variations to specific recommendations in this document. This Part covers both pre- and post-2000 plants.

1.3 Risk-Informed Analysis

This Part covers both safety-related and non-safety-related diesel generator systems. Owners must categorize each diesel generator system according to its safety significance using the ASME-approved risk-informed methodology or other risk ranking methodologies accepted by the regulator with the conditions in the applicable safety evaluations.[2]

[1] The prescribed tests in this Part are consistent with the requirements specified in U.S. NRC Regulatory Guide 1.9, Revision 4 and IEEE 387-1995 (reaffirmed September 2007), Section 7.4, "Periodic Testing."

[2] For U.S. plants, the implementation of Code Case OMN-3 included the conditions discussed in Regulatory Guide 1.192.

1.4 Subsystems Included Within the Diesel Generator Boundary

Figure 1 provides the simplified boundary for the diesel engine and associated subsystems covered by this Part. Since there are varieties of diesel makes, sizes, applications, etc., each owner/operator must make the final designation of the applicable diesel generator and subsystem boundary. As the engine cannot be tested independently of the generator, the owner/operator must consider the effects of inservice testing on the entire system (the diesel engine and the associated subsystems).

Typical principal equipment for associated diesel generator subsystems identified in Fig. 1[3] are listed below for owner/operator considerations in the development of a preventive maintenance program. The owner/operator established standby diesel generator maintenance program should account for site-specific and relevant industry operating experience, and be consistent with the recommended periodic maintenance of the manufacturer or as developed by the respective diesel engine owners group.

1.4.1 Engine. Equipment includes (where applicable) the following:

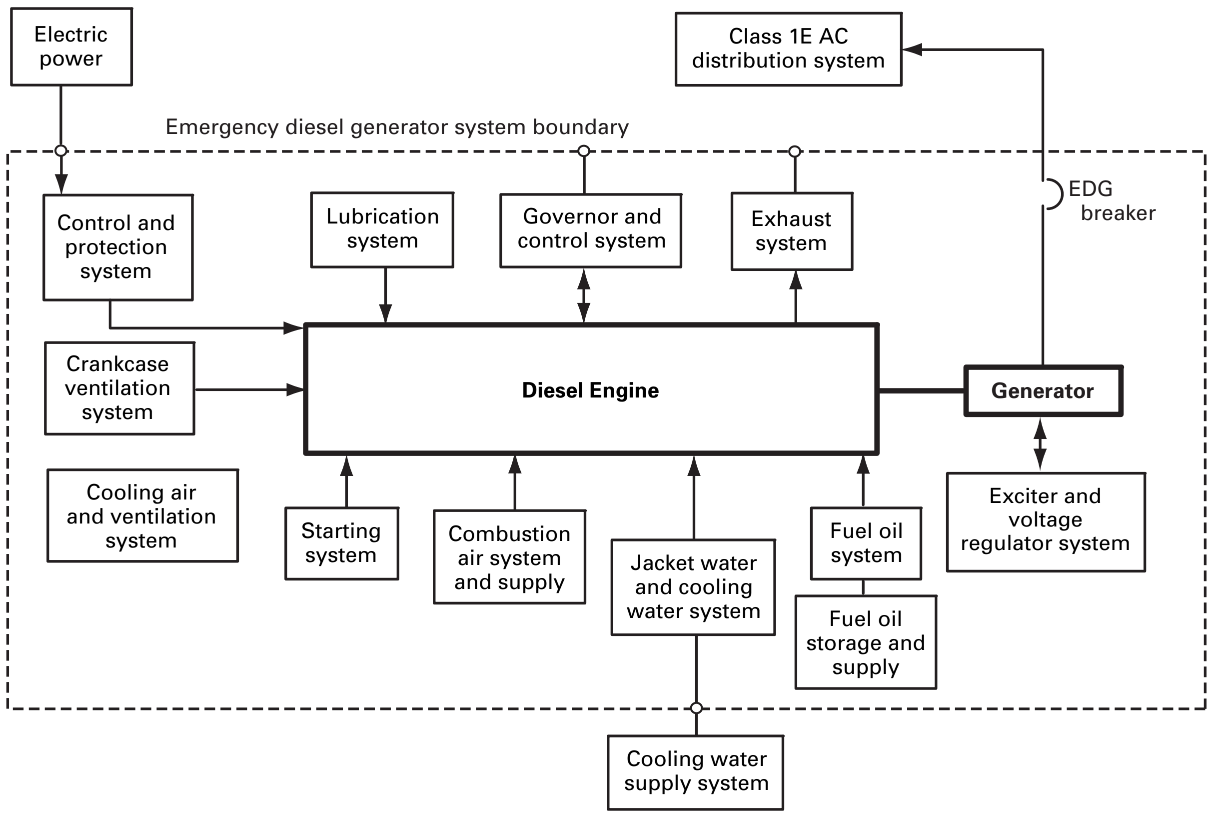
(a) crankcase
(b) crankshaft and bearings
(c) power assemblies
(d) valve gear
(e) camshafts and bearings
(f) damper
(g) gear trains
(h) flywheel

1.4.2 Lubrication Subsystem. Equipment includes (where applicable) the following:

(a) lube oil sump and makeup tank

[3] Figure 1 is a system boundary diagram that shows the components of the diesel generator system. This is similar to the system boundary identified by U.S. NRC Regulatory Guide 1.9, Revision 3 and Revision 4, Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants. Even though some of these components may not be physically located on the diesel skid, these components' design purpose of solely supporting the diesel qualify them as skid-mounted equipment.

Fig. 1 Boundary and Support Systems of Emergency Diesel Generator Systems



(b) suction strainers and foot valves
(c) discharge strainers
(d) filters
(e) transfer valves for duplex filter and strainer arrangements
(f) pressure-regulating, relief, check, and thermostatic valves
(g) standby heaters and thermostat
(h) engine-driven lube oil pumps
(i) circulating (primary or backup) and prelube/postlube pumps
(j) all piping, tubing, and associated components
(k) lube oil heat exchanger
(l) instrumentation and controls
(m) flexible hoses

1.4.3 Jacket Water and Intercooler Subsystem. Equipment includes (where applicable) the following:
(a) jacket water heat exchanger
(b) intercooler systems
(c) radiators and associated fan(s)
(d) governor oil heat exchanger
(e) standby heater and associated thermostat
(f) keep-warm water pump
(g) jacket water and intercooler pumps (primary or standby)
(h) thermostatic valves, check valves, and block valves
(i) standpipes and overflow, pressure cap, level indicators, and expansion tanks
(j) piping, tubing, and associated components
(k) instrumentation and controls
(l) flexible hoses

1.4.4 Starting Subsystem. Equipment includes (where applicable) the following:
(a) batteries/charging systems
(b) electric/pneumatic start motors
(c) air compressors
(d) air receivers; relief, check, and air-start solenoid valves; and piping, tubing, and associated components
(e) pressure-reducing valves, shuttle valves, block valves, check valves, and pressure regulators
(f) air dryers, strainers, filters, compressor, intercoolers and aftercoolers, and air dryer associated components
(g) air-start distributors and associated air injection valves
(h) instrumentation and controls
(i) flexible hoses

1.4.5 Combustion Air Intake Subsystem. Equipment includes (where applicable) the following:
(a) intake air filter

(b) intake air silencer
(c) intake air manifold and all piping, tubing, ductwork, and associated components
(d) mechanical blowers, superchargers, and scavenging pumps
(e) turbocharger (compressor)
(f) intercooler
(g) instrumentation and controls
(h) turbo boost system (nozzles, hoses, solenoid valves, air receiver, and compressor)

1.4.6 Exhaust Subsystem. Equipment includes (where applicable) the following:
(a) turbocharger (turbine)
(b) exhaust silencer and spark arrestor
(c) exhaust relief valve and stack
(d) exhaust manifold, piping, ductwork, connectors, bellows, joints, and associated components
(e) instrumentation and controls

1.4.7 Fuel Oil Subsystem. Equipment includes (where applicable) the following:
(a) fuel oil storage tank(s)
(b) fuel oil transfer pump(s), motor(s), and automatic transfer valve(s)
(c) day tank(s)
(d) strainers and filters
(e) booster pump(s) and associated drive belt(s)
(f) pressure-regulating, relief, check, transfer, and block valves
(g) fuel oil headers, supply and return
(h) fuel injection pumps, spray nozzles, injectors, and high-pressure injection tubing
(i) fuel control and shutdown system
(j) piping, tubing, and associated components
(k) instrumentation and controls
(l) flexible hoses

1.4.8 Crankcase Ventilation Subsystem. Equipment includes (where applicable) the following:
(a) vent pipe
(b) relief doors and valves
(c) crankcase vent fan, eductor, and pump, including oil mist separator and oil return line
(d) crankcase and sump vent system
(e) piping, tubing, and associated components
(f) instrumentation and controls
(g) flexible hoses

1.4.9 Governor and Control Subsystem. Equipment includes (where applicable) the following:
(a) mechanical–hydraulic governor, including associated linkages to fuel racks, hydraulic fluid, piping, tubing, and associated components
(b) pneumatic, hydraulic, or electric governor booster
(c) electric governor, speed sensor, and electromechanical interface
(d) engine fuel pump control linkage
(e) electronic fuel injection control
(f) overspeed trip
(g) instrumentation and controls

1.4.10 Generator Subsystem. Equipment includes (where applicable) the following:
(a) coupling to diesel engine
(b) generator (including strip heaters)
(c) protective shutdown system
(d) instrumentation and controls

1.4.11 Ventilation System and Cooling Subsystem. Equipment includes (where applicable) the following:
(a) filters
(b) fans and motors
(c) vents, dampers, actuators, louvers, and ducts
(d) instrumentation and controls

1.4.12 Exciter and Voltage Regulator Subsystem. Equipment includes (where applicable) the following:
(a) generator exciter
(b) voltage regulator system
(c) generator/exciter electrical connections
(d) other instrumentation and controls

1.4.13 Control and Protection Subsystem. Equipment includes (where applicable) the following:
(a) devices for automatic and manual starting
(b) devices for load shedding
(c) synchronizing equipment
(d) fast transfer switches
(e) DC power supplies dedicated to the diesel engine

1.4.14 Diesel Generator Output Breaker. Equipment includes (where applicable) the following:
(a) output breaker and associated relays (components may not be located in the output breaker panel)
(b) control switches and auxiliary contact

1.5 Definitions

These definitions are provided to ensure a uniform understanding of selected terms used in this Part. Several additional terms, often not well-defined elsewhere, are included to help provide uniformity and clarity to the nuclear power industry's use of these terms as they relate to the testing and maintenance of diesel generator systems.

abnormal condition: an engine condition defined by situations and applications as outside acceptable parameters, as defined by the manufacturer and users.

bar engine over: the act of rotating the engine slowly for maintenance or inspection purposes.

barring device: an arrangement that provides for the slow rotation of the engine.

blowdown: the act of blowing moisture and/or oil accumulation from the engine cylinders through opened cylinder petcocks. Also applies to blowing moisture from the starting air receivers and air system.

continuous load/rating: the power output capability that the diesel generator can operate for a period of time, as specified by the manufacturer, with only scheduled outages for maintenance.

cranking: the act of using external power sources (electricity or air pressure) to cause the engine's crankshaft to rotate without the engine sustaining operation with its own combustion and before the engine provides useful work.

diesel drives: the assembly or aggregate of assemblies of one or more single or multiple diesel engines used as prime movers.

equilibrium temperature: the condition at which the diesel engine jacket water and lube oil temperatures are both within ±10°F (5.5°C) of the normal operating temperatures established by the engine manufacturer.

excessive vibration: a condition during operation where an engine, or its component parts, vibrates more than is generally accepted and where a condition exists that is exceeding the acceptance criteria.

keep-warm system: system(s) that maintains jacket water, fuel oil, and/or lube oil temperatures at warm standby values recommended by the engine manufacturer.

major maintenance: corrective maintenance associated with disassembly and reassembly of engine components as part of an "open and inspect" maintenance practice. It also applies to the maintenance that returns the diesel engine to operating status following an abnormal event. Examples of such an event are crankcase explosion and piston-rod ejection.

maximum available load: the amount of load that is practical for applying to the diesel engine for testing purposes on an isolated bus. The maximum available load may be at or below the continuous load rating of the diesel engine.

standby condition: the condition at which the diesel engine jacket water, fuel oil, and lube oil systems are maintained by the keep-warm system within the range of temperatures established by the engine manufacturer.

2 NONOPERATING CHECKS

2.1 Post-Maintenance Checks

The owner/operator shall perform an initial check of the engine components and subsystems to provide reasonable assurance that the overall diesel generator unit will operate as designed. This check includes flushes, hydrostatic tests (if required following major repair/replacement activities) of fluid systems, visual checks, functional tests of support components and systems, and additional tests as recommended by the manufacturer.

2.2 Pre-Start Checks

The owner/operator shall perform pre-start checks to provide reasonable assurance that the diesel generator will start and operate as designed without incurring equipment damage. These checks include engine fluid levels, engine pre-lube and keep-warm systems, governor control settings and oil level, starting air system pressure and line-up, generator bearing oil level, visual leak checks, engine bar over if applicable, and those additional inspections as recommended by the manufacturer.

3 TESTING

3.1 Post-Maintenance/Baseline Testing

The owner/operator shall perform testing post-maintenance on inservice engines that is above and beyond those normal maintenance-related tests specified by the diesel engine manufacturer. These tests shall be performed to demonstrate the starting and operational adequacy of the overall diesel generator unit. Note that the reliability tests for newly installed diesel generator sets described in IEEE 387-1995 (reaffirmed September 2007), Section 7.3, "Pre-operational Testing," do not apply since new unit reliability will have been established during initial type qualification testing. Section 4 of this Part lists the data that should be considered for engines that have had major maintenance performed.

Post-maintenance testing (PMT) is to verify that the diesel generator is capable of performing its intended function and to establish new performance baseline data where appropriate. PMT establishes current operational readiness and provides reasonable assurance of function in the future. Verification that a diesel generator is capable of performing its intended function may be accomplished by verifying that the applicable plant Technical Specification surveillance tests are re-performed after the maintenance activity. The owner/operator is required to establish the appropriate conditions to test a component to establish operability following maintenance.

The design function of the maintained component, potential failure modes (e.g., failure to pump, electrically operate), and conditions that may lead to a failure (e.g., vibration, operational cycles) must be considered when establishing the scope of the functional testing/PMT and the run duration. The diesel generator PMT run duration should be established based on the need to challenge components replaced or repaired during maintenance. Extended run duration is generally not effective in detecting fatigue-related failure mechanisms based on the low forcing function frequencies associated with diesel generator running speed. Once thermal equilibrium has been reached, extended runs don't provide significantly more confidence that a failure won't occur during a subsequent run. Additionally, electrical components tend to fail during transients associated with changes of state.

3.1.1 General Testing Guidance for Diesel Generator Components

3.1.1.1 General Mechanical Components. Typically all mechanical components should be subjected to a load-run test (see para. 3.2.2) as a PMT, where the appropriate operating parameters should be validated against vendor-recommended limits as well as historical operating data. Leak checks and vibrational checks (see para. 5.2) should be performed as appropriate.

3.1.1.2 Major Engine Components. These components have a direct effect on horsepower output (e.g., pistons, connecting rods, crankshafts, cylinder assemblies, heads, cams, injectors, turbochargers, gear trains). As horsepower impacts both transient and steady-state loading, a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate, a load-run test (see para. 3.2.2), as well as a margin test (at 110% of continuous rating) should be performed to ensure rated horsepower is obtained. Additionally, engine analysis (see para. 5.1) should be performed. These tests should be performed in addition to any manufacturer-recommended break-in runs.

3.1.1.3 Active Starting System Components. These components change state in order to start the diesel generator (e.g., solenoid valves, pressure-regulating valves, air control valves, check valves, starting motor). A fast-start test (see para. 3.2.3) should be performed to ensure that the diesel generator reaches rated frequency and voltage as designed. Test times should be compared to historical data.

3.1.1.4 Engine Governor or Electronic Fuel Injection Control. The governor or electronic fuel injection control affect both transient and steady-state control of engine load and speed. As a minimum, a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate, a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest-load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist. A leak check should be performed on governor actuators and associated components as applicable.

3.1.1.5 Voltage Regulator. The voltage regulator affects both transient and steady-state control of the generator output. As a minimum, a fast-start test (see para. 3.2.3), a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist.

3.1.1.6 Generator. The generator has a direct effect on both transient and steady-state loads on the diesel generator. As a minimum, a fast-start test (see para. 3.2.3), a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load-rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest-load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist.

3.1.1.7 Other Diesel Generator Controls. Other controls may include various relays and protective trips. The specific function of the control must be considered in determining the appropriate PMT. Controls associated with starting the diesel generator should be subjected to a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate. Controls associated with the governor or voltage regulator should be subjected to the appropriate loading or transient tests based on their function. An overspeed trip test should be performed when components associated with the overspeed trip are disturbed or replaced. Testing of protective trips should take into account the function of the trip during design conditions.

3.2 Periodic Tests

Performance of periodic diesel generator tests and monitoring operating parameters provide the owner/operator with an immediate determination of the engine performance and material condition. The owner/operator shall perform periodic tests in accordance with plant procedures. The periodic testing frequencies identified in this Part are recommendations. They are identified as a matter of convenience for the monitoring of operating parameters and to coincide with plant testing programs.

Table 1 states the periodicity of when the tests in paras. 3.2.1 through 3.2.14 should be performed. Class 1E

Table 1 Periodic Tests

		Periodicity									
		Monthly		Quarterly		6 Months		18-24 Months		10 Years	
Ref.	Tests	Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E
3.2.1	Slow start	X	. . .	. . .	X	. . .	. . .	. . .	. . .	. . .	. . .
3.2.2	Load run	X	. . .	. . .	X	. . .	. . .	. . .	. . .	. . .	. . .
3.2.3	Fast start	. . .	. . .	. . .	. . .	X	NA	. . .	. . .	. . .	. . .
3.2.4	LOOP	. . .	. . .	. . .	. . .	. . .	. . .	X	As req.	. . .	. . .
3.2.5	SIAS	. . .	. . .	. . .	. . .	. . .	. . .	X	NA	. . .	. . .
3.2.6	SIAS and LOOP	. . .	. . .	. . .	. . .	. . .	. . .	X	NA	. . .	. . .
3.2.7	Largest-load rejection	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .
3.2.8	Design-load rejection	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .
3.2.9	Endurance and load margin	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .
3.2.10	Hot restart	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .
3.2.11	Synchronizing	. . .	. . .	. . .	. . .	. . .	. . .	X	X	. . .	. . .
3.2.12	Protective trip bypass	. . .	. . .	. . .	. . .	. . .	. . .	X	As req.	. . .	. . .
3.2.13	Test mode override	. . .	. . .	. . .	. . .	. . .	. . .	X	As req.	. . .	. . .
3.2.14	Independence	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	X	As req.

is safety-related systems and Non-1E is non-safety-related.

3.2.1 Slow-Start Test

Class	Test Frequency
Safety-related system	Monthly
Non-safety-related system	Quarterly

This test demonstrates proper startup from standby conditions and verifies that the required design voltage and frequency are attained. The diesel generator should reach rated speed on a prescribed schedule to minimize stress and wear. This is a functional test to verify proper operation. Reducing the number of starts for a non-safety-related system will reduce engine wear. However, extending test frequency beyond quarterly will further reduce oil retention on component wear surfaces and increase oxidation on electrical contact surfaces.

3.2.2 Load-Run Test

Class	Test Frequency
Safety-related system	Monthly
Non-safety-related system	Quarterly

This test demonstrates 90% to 100% of the continuous rating of the diesel generator for an interval of not less than 1 hr and until attainment of temperature equilibrium. This test may be accomplished by synchronizing the generator with offsite power. The loading and unloading of a diesel generator during this test should be gradual and based on a prescribed schedule that is selected to minimize stress and wear on the diesel generator. This is a functional test of engine and system components to assure reliability. Testing may be performed at a nominal power factor suitable to the grid condition at the time of the test.

3.2.3 Fast-Start Test

Class	Test Frequency
Safety-related system	Every 6 months
Non-safety-related system	Not applicable (NA)

This test demonstrates proper startup from standby conditions and verifies that the required design voltage and frequency are attained. The acceptance criteria for frequency and voltage should be equal to or greater than the minimum required voltage and frequency within the specified time allowance for the safety-related loads. Consider defining normal standby using a time-at-rest requirement instead of temperature to preclude preconditioning debates.

3.2.4 Loss-of-Offsite Power (LOOP) Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

(a) Safety-Related System. This test simulates the safety-related diesel generator response to a LOOP to demonstrate that

(1) the emergency buses are de-energized and the loads are shed from the emergency buses

(2) the diesel generator starts on the auto-start signal from its standby conditions; attains the required voltage and frequency, and energizes permanently connected loads within acceptable limits and time; energizes all auto-connected shutdown loads through the load sequencer; and operates for greater than or equal to 5 min

If the required safety loads are not available, one or more equivalent loads may be used.

(b) Non-Safety-Related System. If the plant design incorporates LOOP response for the non-safety-related diesels, this test simulates the non-safety-related diesel response to a LOOP to demonstrate that

(1) the buses are de-energized and the loads are shed from the buses

(2) the diesel generator starts on the auto-start signal from its standby conditions; attains the required voltage and frequency, and energizes permanently connected loads within acceptable limits and time; energizes all auto-connected loads and sequenced loads through the load sequencer, if required; and operates for greater than or equal to 5 min

If the required loads are not available, one or more equivalent loads may be used.

3.2.5 Safety Injection Actuation Signal (SIAS) Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Not applicable (NA)

This test demonstrates that on an SIAS, the diesel generator starts on the auto-start signal from its standby conditions, attains the frequency and voltage within acceptable limits and time, and operates for a minimum of 5 min.

3.2.6 SIAS and LOOP Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Not applicable (NA)

This test demonstrates that the diesel generator can satisfactorily respond to a LOOP in conjunction with SIAS by verifying that the unit starts on the auto-start signal from its standby conditions, attains the frequency and voltage within acceptable limits and time, energizes the auto-connected shutdown loads through the load sequencer within the acceptable limits of pump start time, and operates for a minimum of 5 min.

3.2.7 Largest-Load Rejection Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the diesel generator's capability to reject a load equal to loss of the largest single load while operating at its design load power factor, and verifies that the frequency and voltage requirements are met and the unit will not trip on overspeed. This test challenges the ability of the engine governor (or electronic fuel injection control) and generator voltage regulator to maintain the remaining connected loads. For a non-safety-related system, the test could be performed at unity power factor to reduce stresses on the generator system.

3.2.8 Design-Load Rejection Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the diesel generator's capability to reject a load, equal to 90% to 100% of the continuous rating and equal to or greater than 100% of the design load, while operating at its design-load power factor, and verifies that the voltage requirements are met and that the unit will not trip on overspeed. This test challenges the ability of the engine governor (or electronic fuel injection control) to recover to rated speed without actuating the overspeed trip. For a non-safety-related system, the test could be performed at unity power factor to reduce stresses on the generator system.

3.2.9 Endurance and Load Margin Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the capability of the diesel generator at continuous rating and worst-case power factor for an interval of not less than 24 hr. Of this period, 2 hr or more should be at a load equal to 105% to 110% of the diesel generator's continuous rating, and 22 hr or the remaining hours should be at a load equal to 90% to 100% of the generator's continuous rating. The test process should verify that frequency and voltage requirements are maintained. This test is to demonstrate the diesel generator's capability to carry load for an extended run. For a non-safety-related system, the test could be run at continuous rating of the diesel generator for no less than 8 hr at rated power factor. The 8-hr duration is consistent with IEEE 387-1995 (reaffirmed September 2007).

3.2.10 Hot Restart Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the hot restart functional capability at full load–temperature conditions (after the diesel generator has operated for 2 hr at continuous rating) by verifying that the diesel generator starts on a manual or auto-start signal, attains the required frequency and voltage within acceptable limits and time, and operates for longer than 5 min. This test may be performed following the endurance and load margin test described above. The intent is to demonstrate that the diesel generator is capable of restarting after a normally scheduled surveillance run, i.e., the diesel generator is "hot" rather than in the normal standby temperature range.

3.2.11 Synchronizing Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

The test demonstrates the ability to

(a) synchronize the diesel generator unit with offsite power while the unit is connected to the emergency load

(b) transfer this load to the offsite power

(c) isolate the diesel generator unit

(d) restore the diesel generator unit to standby status

3.2.12 Protective Trip Bypass Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

This test demonstrates that automatic diesel generator unit trips are bypassed as designed. Typically, engine overspeed, generator differential current trip, and those trips retained with coincident logic are not bypassed. This test should also verify that the critical protective trips that are not automatically bypassed perform their intended function.

3.2.13 Test Mode Override Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

This test demonstrates that with the diesel generator operating in the test mode while connected to its bus, a simulated safety injection signal overrides the test mode by

(a) returning the diesel generator to standby operations

(b) automatically realigning the emergency loads to offsite power

3.2.14 Independence Test

Class	Test Frequency
Safety-related system	Every 10 yr
Non-safety-related system	Every 10 yr if required

This test demonstrates that by starting and running (unloaded) redundant units simultaneously, potential common failure modes that may be undetected in single diesel generator unit tests do not occur.

3.3 Other Testing Guidelines

Subsequent to placing a diesel generator into service at a nuclear power plant, the system shall be tested periodically to demonstrate that the capability, availability, and reliability to perform its design function is acceptable. The following guidelines apply:

(a) Some of the periodic tests may be combined and not necessarily performed individually.

(b) The tests do not necessarily have to begin from standby conditions unless specified.

(c) All diesel generator protective trips and alarms should be in operation during the testing.

(d) Periodic testing of the diesel generator unit should not impair the capability of the unit to meet its functional/design requirements in the event of an actual plant emergency.

(e) All tests should be performed in accordance with the manufacturer's recommendations for reducing diesel engine wear, including the prelubing of the engine, post-test cool down, and post-test lubrication.

(f) The periodic testing should involve operation of the diesel engine for a minimum of 1 hr after the equilibrium (jacket water and lube oil) temperatures have been reached or as specified by the plant Technical Specifications.

4 INSERVICE MONITORING OF COMPONENT OPERATING AND STANDBY CONDITIONS

The diesel generator and supporting components are operated periodically during normal engine operational surveillance testing. System performance data should be monitored and trended to eliminate additional testing for individual components. The environment that exists during the periodic engine operation is indicative of engine room conditions during extended engine operation. These conditions ensure that adequate demands are being placed on the equipment, so that operating data/information gathered is a valid indicator of component performance, and long-term degradation of the diesel generator can be identified and corrected. Given below are the diesel generator subsystem components and the parameters to be monitored as applicable to station requirement/design for the standby diesel generator system.

Engine operating data should be recorded with the diesel engine running at rated load and stabilized at normal operating temperatures. In many cases, a subsystem and/or component's performance can be monitored by more than one parameter. When a desired parameter is not available, another accessible parameter may be available to satisfy the monitoring requirements. Note that the operating range of each parameter may vary between engine runs, depending on the operating condition, i.e., outside temperature and barometric pressure. During an endurance surveillance run, operating data should be recorded at least hourly to provide the opportunity to detect emerging malfunctions. Operating data recorded during engine surveillance runs should be trended and evaluated, to monitor equipment health and to identify declining performance or material condition.

4.1 Engine

(a) Standby Condition Monitoring Parameters
(1) engine mounting bolts tightness
(2) skid mounting bolts tightness
(b) Operational Performance Monitoring Parameters
(1) engine vibration
(2) engine cylinder pressure
(3) engine RPM

4.2 Lubrication Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for external oil leaks/degradation
(2) engine and turbo lube oil sump levels
(3) lube oil analysis
(4) engine circulating lube oil pressure
(5) engine circulating lube oil temperature
(b) Operational Performance Monitoring Parameters
(1) system visual inspection for external oil leaks/degradation
(2) engine lube oil in/out pressures
(3) turbocharger lube oil in/out pressures
(4) lube oil strainer in/out differential pressure
(5) lube oil filter in/out differential pressure
(6) engine lube oil in/out temperatures
(7) lube oil cooler in/out temperatures

4.3 Jacket Water and Intercooler Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for external cooling water leaks/degradation
(2) radiator/fan visual inspection for degradation
(3) jacket water keep-warm temperature
(4) jacket water keep-warm pressure
(5) coolant level
(6) cooling water chemical analysis
(b) Operational Performance Monitoring Parameters
(1) system visual inspection for external leaks/degradation
(2) service water flow rate
(3) service water temperature
(4) jacket water temperature
(5) engine power output
(6) intake manifold temperature
(7) radiator water/air in/out temperatures
(8) radiator fan vibration
(9) jacket water pump pressure
(10) intercooler pump pressure

4.4 Starting Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for external air leaks/degradation
(2) air compressor oil level
(3) air receiver blowdown
(4) air receiver pressure
(5) air start solenoid valve lubricator operation and oil level
(6) battery/charging systems alarms and local indications
(b) Operational Performance Monitoring Parameters
(1) system visual inspection for external air leaks/degradation
(2) fast start test time
(3) compressor run times
(4) compressed air usage
(5) dryer operation
(6) dew point temperature of compressor/dried air
(7) electrical current consumption

4.5 Combustion Air Intake Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for external leaks/degradation
(2) visual inspection of bird screens and louvers for obstructions
(b) Operational Performance Monitoring Parameters
(1) air filter in/out differential pressure
(2) engine inlet air temperature
(3) intercooler in/out differential pressure
(4) mechanical blower outlet pressure
(5) scavenging pump outlet pressure
(6) supercharger outlet pressure
(7) turbocharger outlet pressure

4.6 Exhaust Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for degradation
(2) visual inspection of wall/roof penetrations for possible fire hazard
(b) Operational Performance Monitoring Parameters
(1) exhaust back pressure
(2) cylinder exhaust temperatures
(3) system visual inspection for degradation

4.7 Fuel Oil Subsystem

(a) Standby Condition Monitoring Parameters
(1) system visual inspection for external fuel oil leaks/degradation
(2) owner-approved acceptance criteria for fuel oil quality/condition
(3) open low-point drains and inspect for water
(4) visual inspection for blockage of tank vents

(b) Operational Performance Monitoring Parameters

(1) system visual inspection for external fuel oil leaks/degradation

(2) fuel oil transfer pump flow rate

(3) fuel oil transfer pump discharge pressure

(4) on-engine fuel oil pump discharge pressure

(5) strainer/filter in/out differential pressure

4.8 Crankcase Ventilation Subsystem

(a) Standby Condition Monitoring Parameters

(1) system visual inspection for external leaks/degradation

(b) Operational Performance Monitoring Parameters

(1) system visual inspection for external leaks/degradation

(2) crankcase pressure

4.9 Governor and Control Subsystem

(a) Standby Condition Monitoring Parameters

(1) governor oil level

(b) Operational Performance Monitoring Parameters

(1) engine speed response during start and load

4.10 Generator Subsystem

(a) Standby Condition Monitoring Parameters

(1) visually check air cooling ports

(2) strip heater operation

(b) Operational Performance Monitoring Parameters

(1) generator bearing vibration

(2) stator temperature

4.11 Ventilation and Cooling Subsystem

(a) Standby Condition Monitoring Parameters

(1) visual inspection of inlet louvers and screens for blockage

(2) diesel room ambient air temperature

(b) Operational Performance Monitoring Parameters

(1) diesel room ambient air temperature

(2) fan vibration

4.12 Exciter and Voltage Regulator Subsystem

(a) Standby Condition Monitoring Parameters

(1) none

(b) Operational Performance Monitoring Parameters

(1) voltage response during start and load

4.13 Control and Protection Subsystem

(a) Standby Condition Monitoring Parameters

(1) overspeed trip mechanism position (where applicable)

(b) Operational Performance Monitoring Parameters

(1) relay responses

4.14 Diesel Generator Output Breaker

(a) Standby Condition Monitoring Parameters

(1) breaker flag

(b) Operational Performance Monitoring Parameters

(1) breaker operation

5 OTHER CONDITION MONITORING METHODS/GUIDELINES

5.1 Diesel Engine Analysis

Class	Test Frequency
Safety-related system	Perform every 24 months as a part of a condition-based maintenance (CBM) program and after completion of major engine maintenance activities to reestablish baseline operating data
Non-safety-related system	Same as safety-related system

(a) General. Diesel engine analysis is an effective tool in support of an inservice testing and/or a CBM program because

(1) it provides the technical basis for developing a performance-based maintenance program

(2) it detects certain degraded engine material conditions or engine performance

(3) it provides the basis for engine tuning adjustments to improve power balance

Diesel engine analysis involves recording specific engine operating parameters during normal operation. These engine operating parameters include engine cylinder pressure (both compression and firing pressure), vibration as recorded by accelerometers, and unusual sounds as recorded by ultrasonic transducers. All three readings are recorded as a function of crankshaft position for each cylinder, fuel injection pump, and injector. Cylinder pressure is analyzed for specific quantitative values (peak pressure, firing pressure angle, cycle variation, etc.) and profiles during operation. Certain known events (intake and exhaust valve closing and opening, fuel injection) are reviewed to verify they occur at the proper timing. Engine analysis is also used to balance and tune the engine to ensure the power from each cylinder is nearly equivalent.

NOTE: Some smaller non-safety-related diesel generators may not have the capability to collect and record engine cylinder firing and compression pressures if they do not have Kiene valve fittings in the cylinder heads.

(b) Benefits. Benefits realized from diesel engine analysis, especially as part of a CBM program, include the following:

(1) Reduced Maintenance. Users of diesel engine analysis experience reductions in maintenance costs by eliminating periodic engine tear downs and part replacements. This is achieved by performing specific maintenance and/or repairs required on selected components identified by engine analysis rather than periodically disassembling the entire machine and replacing components unnecessarily.

(2) Increased Reliability. Long-term reliability increases by reducing failures of newly installed engine components and identifying potential maintenance-induced failures.

(3) Increased Availability. Reduced time required for maintenance activities permits the plant to increase diesel engine availability.

(4) Problem Identification. Issues identified in the past using engine analysis include bent connecting rod, degraded injector/injection pumps, cracked intake and exhaust valves, collapsed valve lifter, and degraded engine timing. These types of problems, when identified early and corrected, avoid major engine failures.

5.2 Vibration Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Machinery vibration is the response of the component structural mass and stiffness combinations when subjected to an excitation. A diesel engine produces harmonic excitations as a function of combustion forces, torque reactions, number of engine cylinders, and cylinder firing order. Other factors influencing vibration include engine balance, generator balance, injector timing, coupling alignment, condition of bearings, and operating conditions.

Vibratory motion can be described in terms of displacement, velocity, or acceleration; all three are used in the diagnoses of vibration problems. Vibration analyses on engine, generator, generator bearing, pumps and motors (circulating water pumps, circulating lube oil pumps, turbo soakback oil pumps, fuel pumps, etc.) should be performed while operating at steady state and within normal operating temperature ranges. Changes in vibration level can occur as a result of changes in operating parameters, e.g., temperature, pressure, and engine load.

In general, machinery vibration is complex and consists of many frequencies. To make use of all the information embedded in the vibration signal, frequency analyses should be performed to determine the dominant frequencies and amplitudes. Vibration amplitudes that are abnormally high are often an indication of an existing mechanical problem that needs identification and correction. The composite amplitude and the amplitudes at discrete frequencies at each measurement location should be trended for condition monitoring.

Frequency spectra obtained from measurements made on the engine and generator structure will reveal low-frequency components at shaft speed originating from unbalances, misalignments, bent shaft, etc. Frequency components originating from the gear mesh in the gearbox are generally referred to as medium-frequency components. They correspond to rotational speed times the number of teeth on the gear (gear mesh frequency). In this frequency range, indication of wear and incipient faults in a gearbox, eccentricity, uneven gear wheels, and misaligned gears will be found. As the gearbox wears, the amplitudes of the gear mesh frequency and its harmonics will increase. Frequency components originating from rolling element bearing incipient faults are generally in a higher frequency range. A crack on the inner race or the outer race will create small impulses every time a roller element passes over it. These impulses will excite the bearing housing at its natural frequency.

In general, the engine–generator structural and driveline natural frequencies, engine–generator forcing frequencies, and gear meshing frequencies are less than 500 Hz. Engine–generator vibration signature up to 500 Hz should be measured and trended to monitor the physical condition of the engine–generator system. In the case of generator roller bearings, vibration signature up to 5,000 Hz or 10,000 Hz is necessary to track the bearing condition.

The owner/operator should refer to the engine manufacturer recommended measurement locations and allowable vibration guidelines. Measurements should be recorded at rated speed during full-load operation. The composite vibratory amplitude and the amplitudes of significant frequency components should be trended and compared to other similar installations.

5.3 Lube Oil Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Engine lubricating oil serves to reduce friction and wear, cool engine parts, and protect against corrosion. Periodic lube oil analysis is a valuable tool for evaluating the condition of the oil and assessing material condition of the engine. Traces of wear metals in the lube oil can be used to identify accelerated component wear. Lube oil analysis results should be trended for condition monitoring.

Lube oil degradation includes oxidation, nitration, permanent viscosity change, and additive depletion. Oil oxidation is often caused by excessive operating temperature; it increases oil viscosity and creates acids that corrode metals and cause wear. Nitration is often a result of improper combustion; it may result in grease-like deposits. Permanent viscosity changes will affect the shear stability of the oil. Oil additives, i.e., dispersants, antioxidants, rust/corrosion inhibitors, and film-strength agents, are consumed as oil ages in service. (Dispersants are needed to suspend deposit-forming contaminants in the oil until they can be removed by the oil filter.) The total base number (TBN) is a key parameter (though not the only factor) for determining whether the oil should be replaced. TBN measures the total amount of basic (alkaline) materials present in the lube oil. Decreases in TBN may indicate reduced acid-neutralizing capacity or depleted additive package. Total acid number (TAN) measures the total amount of acid product present in the lube oil. An increase in TAN indicates oil oxidation or contamination with an acidic product.

Lube oil contaminants include combustion products, fuel, dirt, wear metals, water, and coolant additives. Combustion products (soot, sulfur, etc.) are caused by improper combustion or defective injectors; they will increase oil viscosity, form deposits, and corrode engine parts. Fuel dilution will reduce oil viscosity and cause piston/cylinder scuffing and bearing failures. Dirt and dust are caused by inadequate air filtration and can lead to vital engine part damage. Water can result from coolant leaks or low operating temperature; it will cause rust and corrosion. Water will form sludge by combining with other contaminants.

The lube oil sampling procedure should specify the requirement to collect a well-mixed oil sample, e.g., during engine operation (flowing sample), at the end of or shortly after a surveillance run. The owner/operator should consult the engine manufacturer to determine acceptable lube oil parameters for the specific diesel engine being evaluated.

5.4 Cooling Water Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Engine jacket cooling water is circulated through the engine cylinder liner and head to remove the heat generated during the combustion process. Since untreated water accelerates corrosion of engine parts, a corrosion inhibitor must be added to the jacket-cooling water. While in service, the chemicals in the treated water will deplete slowly as a function of the diesel engine's duty cycle. In order to monitor the effectiveness of the treated water in preventing corrosion, jacket cooling water analysis should be performed regularly and the analysis results should be trended.

5.5 Thermography

Class	Test Frequency
Safety-related system	Perform every 24 months
Non-safety-related system	Perform every 24 months

The use of thermography has been a major addition to predictive maintenance inspection programs for diesel generators and associated electrical components. Thermographic inspection refers to the nondestructive examination of components through the imaging of the thermal patterns at the object's surface through the use of an infrared (IR) detector. The typical approach to thermographic inspection is through the use of a passive IR recording camera, in which the features of interest are naturally at a higher or lower temperature than the background. A thermal imaging camera is a reliable, safe, noncontact, nonintrusive instrument that is able to scan and show the temperature distribution of entire surfaces of machinery and electrical equipment quickly and accurately.

Thermography can reveal and measure heat generation in machines and installations. It shows overheated components, and detects and can prevent breakdowns. The first principle of IR sensing is "many components heat up before they fail." Second, all objects emit thermal radiation in the IR spectrum that is not seen by the human eye. Third, IR cameras convert that radiation to visual images that are calibrated to a temperature scale. This noncontact temperature data can be displayed on a monitor in real time and can be sent to a digital storage device for analysis. Measurement accuracy is typically ±2°C. IR cameras do not require lighting to produce their images, and can see hot spots well before excessive heat or loss of insulation leads to failure. For example, transformer fluid leaks or internal insulation breakdown cause overheating that leads to failures. Impending electrical equipment failures due to overheating and loose contacts can be identified and corrected. Exhaust system leaks, and overheated hydraulic system components and fuel injection pumps, can be identified for corrective action.

A thermographic report, consisting of a visual and an IR photo of the scanned object, a temperature curve, basic thermographic data, and a technical summary, is compiled and used for later comparison on a periodic inspection schedule. As overheated conditions are identified, the plant maintenance team can take corrective action to resolve the problem, thereby preventing costly failures.

6 ALARM AND SHUTDOWN DURING TESTS

During the testing of the diesel engine and its generator, the unit may encounter alarmed conditions. Alarm limits (setpoints) are important, but the diesel engine/generator may still be operable when alarm conditions are encountered. Sometimes the diesel system must be allowed to continue operating to evaluate the alarm conditions. To properly support operations, the owner should establish diesel shutdown limits to ensure the engine has not exceeded limits that may cause the engine system to fail. Some example shutdown limits are as follows:

(a) minimum main lubrication oil pressure
(b) maximum lube oil temperature (out of the engine)
(c) minimum fuel oil header (discharge) pressure
(d) maximum cylinder exhaust temperature
(e) maximum engine exhaust temperature
(f) maximum jacket water temperature (out of the engine)

(g) maximum engine speed

(h) maximum allowable generator winding temperature

(i) crankcase pressure

(j) generator current output

Note that not all of the above example diesel engine alarm and shutdown limits apply to every diesel engine design or installation in nuclear power plants. As such, it is up to the individual plant owner and its technical specifications to apply the appropriate diesel generator alarm and shutdown limits within its operating procedures, with consideration of manufacturer's recommendations.

7 DIESEL GENERATOR OPERATING DATA AND RECORDS

Diesel generators at nuclear power stations may experience relatively few operating hours during their normal service life. These units must reliably respond to an emergency start signal. Good record keeping, data evaluation, and trending are essential tools to properly evaluate engine performance and maintain this type of reliability.

7.1 Data/Records

Nonmandatory Appendices A and B of this Part provide sample tables for data collections.

Section 4 of this Part lists the data that should be considered for collection during periodic inservice testing. The owner/operator has the responsibility for the development of plant-specific data sheets. The owner/operator should consult the engine manufacturer for the determination of critical operating parameters for the specific diesel generator being evaluated.

7.2 Data Evaluation and Trending

Selected operating parameters should be plotted at frequent intervals during operating periods to reveal trends. Examples are given in Nonmandatory Appendix C of this Part to illustrate typical information that can be obtained through trends. These examples illustrate effective data evaluation and trending techniques. The objective is to review and trend the performance of these parameters of engine performance against the manufacturers' accepted values.

7.3 Failure to Function (Root Cause)

An important aspect in maintaining diesel engine reliability is the determination of root causes of a diesel generator's failure to perform its design function. An inadequate assessment of the failure will likely lead to repeat failures. Therefore, it is important to know what caused the engine/generator to fail so that proper corrective measures (both immediate and long-term) can be implemented. Maintaining complete and adequate records of failures and their root causes will enable the owner/operator to prevent malfunctions and identify degraded components. Such records will highlight repeated component failures that degrade diesel generator performance and material condition, and focus on the need for corrective actions to prevent recurrence.

Part 16, Nonmandatory Appendix A
Post-Major Maintenance Test Data

See Fig. A-1 below for test data form.

Fig. A-1 Post-Major Maintenance Test Data Form

Plant ______________________ Unit ______________________
Engine No. ______________________ Engine RPM ______________________
Date ______________________

Engine Parameter			Engine Load Percent 75	100	110
1	Load	kW or hp			
2	Ambient Air Temperature	°F (°C)			
3	Barometric Pressure	in. Hg			
4	Run Duration	hr			
5	Jacket Water Temperature (IN/OUT)	°F (°C)			
6	Turbo Water Temperature (IN)	°F (°C)			
7	Turbo Water Temperature (OUT)	°F (°C)			
8	Service Water Pressure (IN/OUT)	psig			
9	Service Water Temperature (IN/OUT)	°F (°C)			
10	Intercooler Water (IN/OUT)	°F (°C)			
11	Lube Oil Heat Exchanger Water (IN/OUT)	°F (°C)			
12	Jacket Water Heat Exchanger Water (IN/OUT)	°F (°C)			
13	Lube Oil Pump Outlet Pressure	psig			
14	Lube Oil Filter Pressure (INLET/OUTLET)	psig			
15	Lube Oil Header Pressure	psig			
16	Turbo Lube Oil Pressure (TO TURBO)	psig			
17	Rack Reading/Fuel Pressure				
18	Lube Oil Temperature (IN/OUT)	°F (°C)			
19	Exhaust Temperature Turbo (TO/FROM)	°F (°C)			
20	Combined Exhaust Temperature	°F (°C)			
21	Exhaust Back Pressure	in. H_2O			
22	Air Intake Pressure	in. Hg			
23	Crankcase Vacuum	in. H_2O			

Turbocharger Lube Oil Brand and Type ______________________
Governor Lube Oil Brand and Type ______________________
Engine Lube Oil Brand and Type ______________________

Part 16, Nonmandatory Appendix B
Functional/Inservice Test Data

See Fig. B-1 below for test data form.

Fig. B-1 Functional/Inservice Test Data Form

Plant ____________ **Engine No.** ____________ **Engine Serial No.** ____________

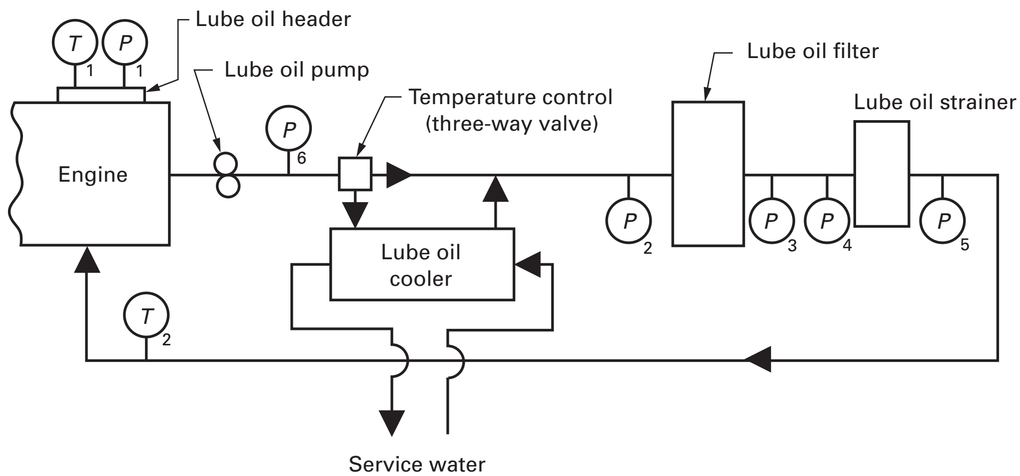
1	Engine Run Time Start/Stop	Time							
2	Ambient Air Temperature	°F (°C)							
3	Load	kW							
4	Barometric Pressure	in. Hg							
5	Engine RPM	RPM							
6	Service Water Pressure (IN/OUT)	psig							
7	Service Water Temperature (IN/OUT)	°F (°C)							
8	Jacket Water Heat Exchanger Temperature (IN/OUT)	°F							
9	Jacket Water Pressure Pump Discharge Pressure	psig							
10	Jacket Water Temperature (IN)	°F (°C)							
11	Jacket Water Temperature (OUT)	°F (°C)							
12	Air Intercooler Water (IN)	°F (°C)							
13	Air Intercooler Water (OUT)	°F (°C)							
14	Lube Oil Heat Exchanger (IN/OUT)	°F (°C)							
15	Lube Oil Pressure Pump Outlet	psig							
16	Lube Oil Filter Pressure (INLET/OUTLET)	psig							
17	Lube Oil Pressure at Header	psig							
18	Fuel Oil Pressure Before/After Filter	psig							
19	Exhaust Temperature to Turbo	°F (°C)							
20	Exhaust Temperature from Turbo	°F (°C)							
21	Exhaust Pressure to Turbo	in. Hg							
22	Turbo Exhaust Stack Pressure	in. H_2O							
23	Pre-Turbo Air Intake Pressure	in. H_2O							
24	Air Intake Manifold (Receiver) Pressure	in. Hg							
25	Air Intake Manifold (Receiver) Temperature	°F (°C)							
26	Crankcase Vacuum	in. H_20							
27	No. 1 Injection Pump Rack Reading	...							
28	Cylinder Exhaust Temperature	°F (°C)							
29	Cylinder No. 1/No. 2	°F (°C)							
30	Cylinder No. 3/No. *n* [Note (1)]	°F (°C)							
31	Lube Oil Makeup	gal							
32	Fuel Oil Consumption	gph							

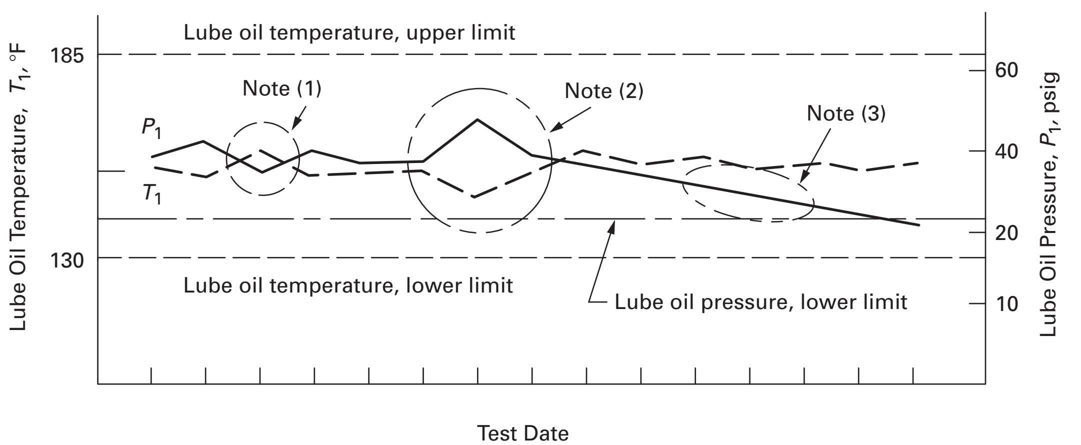
NOTE:
(1) *n* represents the total number of cylinders.

Part 16, Nonmandatory Appendix C
Data Trending Examples

See Figs. C-1 through C-5 on the following pages for data trending examples.

Fig. C-1 Typical Lube Oil System **(15)**





Trend Plotting — Lube Oil Temperature, T_1, and Lube Oil Pressure, P_1

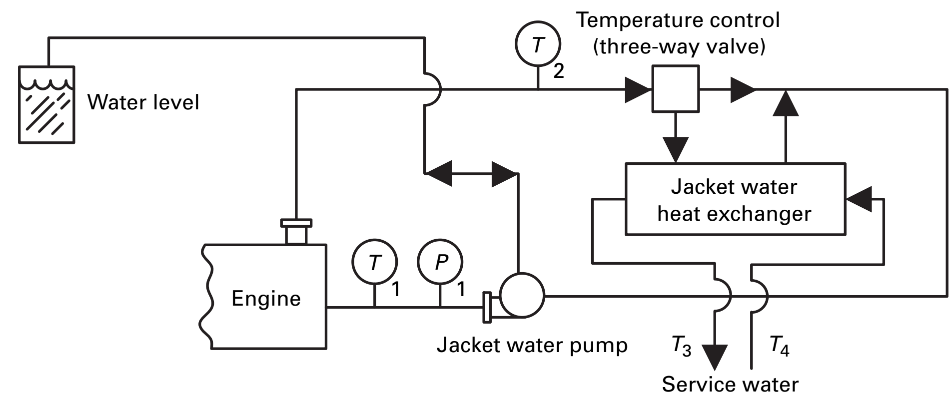
NOTES:

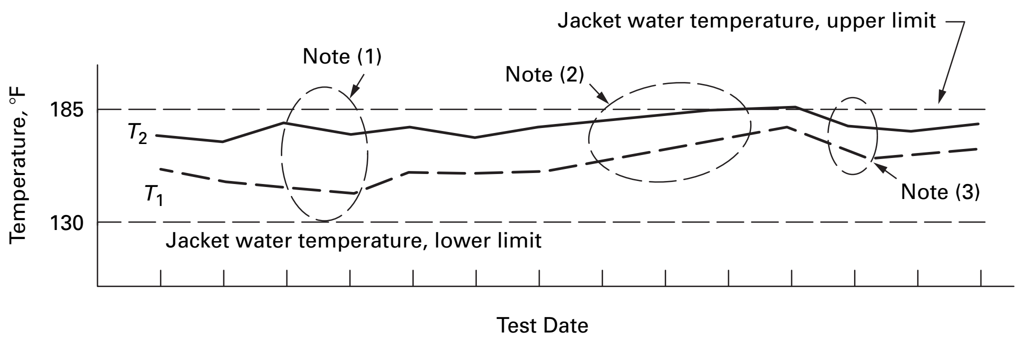
(1) Low lube oil pressure with high lube oil temperature
 (a) faulty temperature control (three-way) valve
 (b) restricted service waterflow

(2) High lube oil pressure with low lube oil temperature: data taken prior to engine reaching equilibrium temperature.

(3) Lube oil pressure is deteriorating. Investigation should be made as to cause, although the lube oil pressure is still above the minimum. Possible causes
 (a) pressure drop across lube oil filter, or strainer is high
 (b) lube oil pump relief valve faulty
 (c) bearing failures
 (d) lube oil system leakage
 (e) lube oil dilute with fuel oil

Fig. C-2 Typical Jacket Water System





Trend Plotting — Jacket Water Temperature to Engine, T_1, and From Engine, T_2

NOTES:

(1) High ΔT across the engine. Possible causes, with $T_4 - T_3$ = constant, are

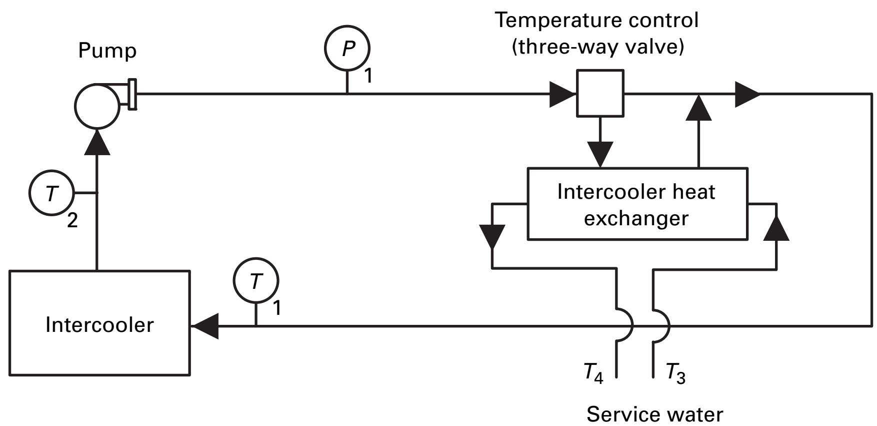
- *(a)* air in system
- *(b)* combustion gas to jacket water leak
- *(c)* restriction in jacket water system

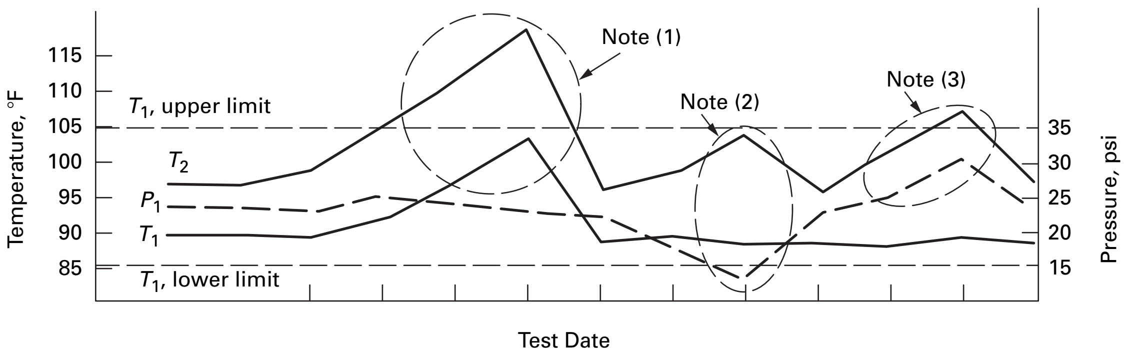
(2) ΔT satisfactory, but temperature increasing. Possible causes are

- *(a)* heat exchanger fouling
- *(b)* faulty three-way temperature valve
- *(c)* seawater system restricted
- *(d)* service water inlet temperature too high

(3) Normal operation conditions

Fig. C-3 Intercooler Water System





Trend Plotting — Air Cooler Water Temperature to T_1 and From T_2 Cooler Pump Pressure P_1

NOTES:

(1) Both temperatures rising; pressure remains constant

  (a) temperature control valve (three-way) failing

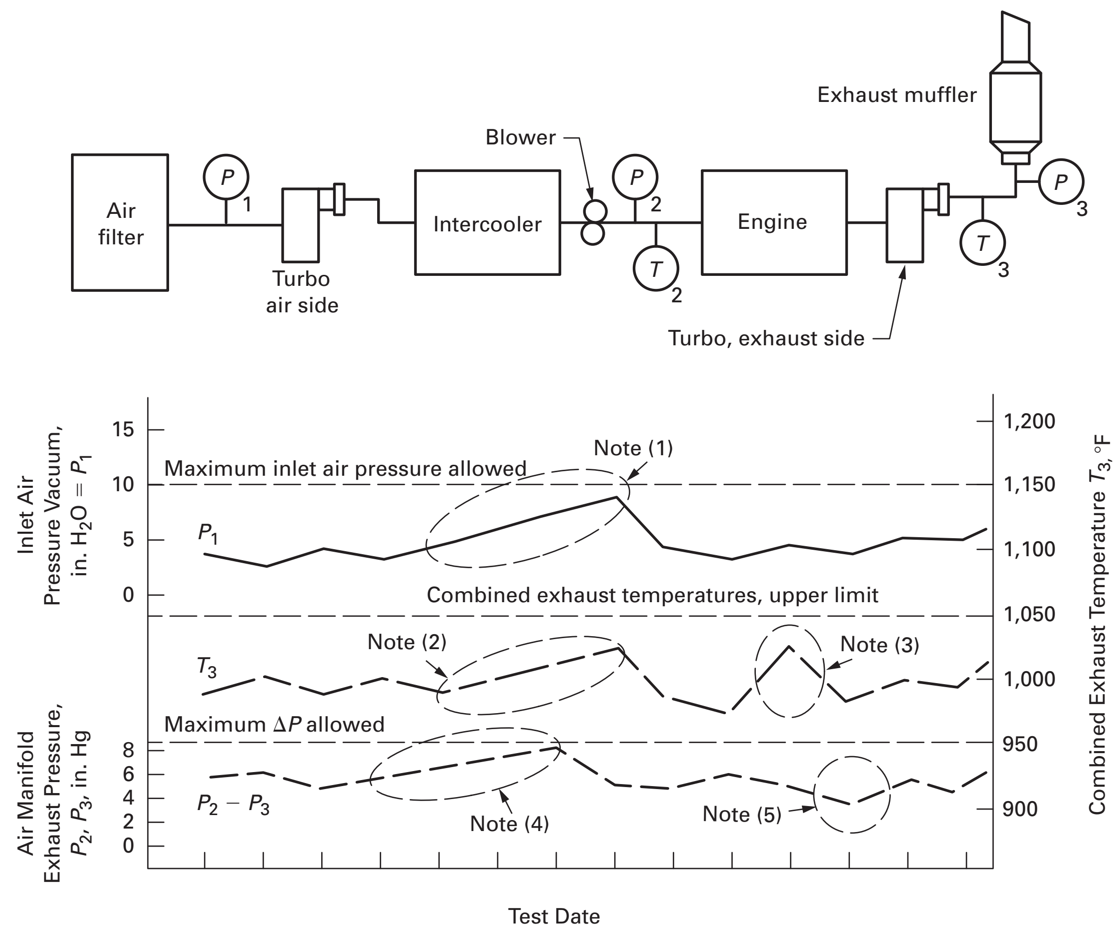
  (b) restricted service water flow ($T_4 - T_3$ rising)

(2) Temperature rise across air cooler and decreasing pump discharge pressure: air in system.

(3) Temperature rise across air cooler and pump discharge pressure increasing: coolers becoming clogged and requiring cleaning.

(15)

Fig. C-4 Typical Air/Exhaust System



Trend Plotting — Air/Exhaust System

Inlet Air Pressure (Vacuum) − P_1 =_______

Air Manifold/Exhaust Back Pressure = $P_2 - P_3$ =_______

Combined Exhaust Temperature = T_3 =_______

NOTES:

(1) Gradually increasing inlet air vacuum: inlet air filters plug and require cleaning or changing.

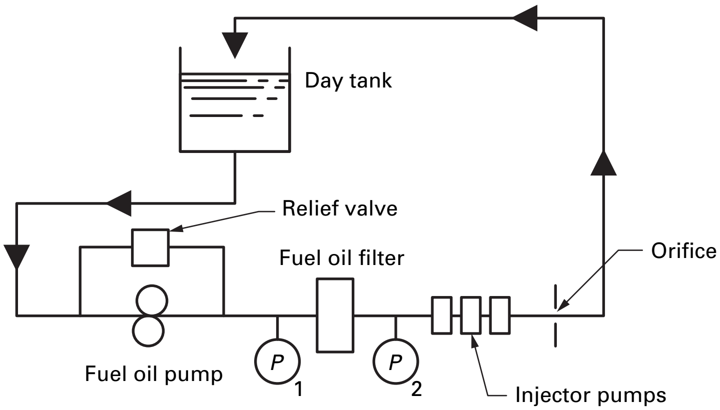
(2) Gradually increasing combined exhaust temperatures may be caused by
- *(a)* exhaust/turbocharger flow restriction
- *(b)* turbo deficiency
- *(c)* low air flow caused by plugged air inlet filters
- *(d)* injection timing change (retarded)
- *(e)* faulty injection nozzle, not proper spray pattern

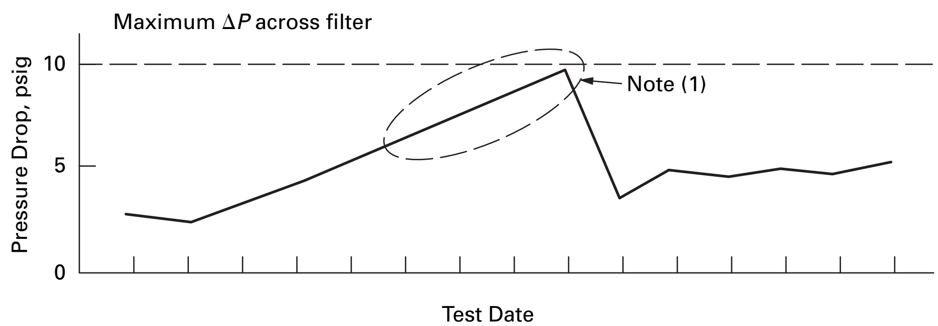
(3) High combined exhaust temperatures. Possible causes are
- *(a)* faulty injection nozzle, nozzle streams foul
- *(b)* injection timing change (retarded)

(4) Increasing Δ*P* across engine. Possible causes are
- *(a)* exhaust flow restrictions
- *(b)* turbocharger deficiency

(5) Low Δ*P* along with low inlet air vacuum and low combined exhaust temperatures: could indicate the test load was low.

Fig. C-5 Typical Fuel Oil System





Trend Plotting — Fuel Filter $\Delta P = P_1 - P_2$

NOTE:
(1) Pressure drop across filter increasing: filter needs cleaning or elements need replacement.

Part 21
Inservice Performance Testing of Heat Exchangers in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for preservice and inservice testing to assess the operational readiness of certain heat exchangers used in nuclear power plants.

The heat exchangers covered are those required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Part establishes test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and record requirements.

1.2 Exclusions

This Part does not address the following:

(a) flow-induced vibration
(b) structural integrity
(c) pressure-retaining capability
(d) erosion or corrosion
(e) other mechanical or structural performance concerns
(f) effects of system performance on heat exchangers (e.g., the system providing insufficient flow to a heat exchanger)
(g) any related system testing (e.g., flow balance testing)
(h) steam generators

1.3 Owner's Responsibility

The Owner shall identify, based on individual plant design basis, those heat exchangers that are considered to be covered by this Part and shall prioritize those heat exchangers in accordance with the guidance provided in this Part. The Owner shall select the most appropriate test or monitoring method and interval for each heat exchanger, so identified, based on the criteria contained in this Part.

The Owner shall be responsible for the operational readiness of all safety-related heat exchangers by following the program requirements as described in para. 5.1.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

accuracy: the closeness of agreement between a measured value and the true value.

baseline data: data collected at specific operating conditions that establish a basis to which subsequent data may be compared.

baseline test: a performance test to establish baseline data.

bias error: the difference between the average of the total population and the true value.

biofilm: a fouling layer consisting of microorganisms and their by-products.

clean fluid: of the two fluids, the one that has the lesser potential for fouling a heat exchanger.

component design limit: that value of heat exchanger performance (usually specified by the manufacturer as the design point) such that if exceeded, although not affecting the operational readiness of the component, may result in component degradation and component reliability concerns.

confidence level: the relative frequency that the calculated statistic is correct.

cooling fluid: any fluid (e.g., water, air, or oil) that serves to carry heat away from the process fluid by the transfer of heat through the heat exchanger.

correlational uncertainty: the uncertainty embedded in the calculational process due to the mathematical models employed (e.g., heat-transfer film coefficients).

coverage: the frequency at which an interval estimate of a parameter may be expected to contain the true value.

design accident conditions: the set of conditions and constraints that are to be satisfied by the heat exchanger for the heat exchanger to meet the safety requirements of the system that it serves.

design basis: information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design.

design point: the set of operating conditions and constraints that are satisfied by the heat exchanger as specified in the heat exchanger specification sheet.

exclusion criteria: the set of conditions that must be avoided for a testing or monitoring method to be effective.

film coefficient: the rate of heat transfer per unit area per unit temperature differential across the boundary layer between either the cooling or the process fluid and the heat-transfer surface.

flow blockage: a reduction in heat-transfer surface or a reduction in flow rate caused by fouling.

fouling fluid: of the two fluids, the one that has the greater potential for fouling a heat exchanger.

fouling resistance: a resistance to heat flow caused by the deposition of corrosive products, dirt, or other foreign material on a heat-transfer surface.

heat duty: the heat transferred per unit of time from one fluid to another.

inclusion criteria: the set of conditions that must be satisfied for a testing or monitoring method to be effective.

inservice test: a test to determine the operational readiness of a structure, system, or component after first electrical generation by nuclear heat.

instrument delay: the characteristic of measuring instruments to give an indicated value that lags the actual value during transient conditions.

instrument loop: two or more items working together to provide a single output.

measurement error: the difference between the true value and the measured value of a parameter. It includes both bias and precision errors.

monitoring method: a method that is used to indirectly evaluate heat exchanger thermal performance.

nominal result: the test result that is calculated using average parameter values.

operability: a system, subsystem, train, component, or device shall be operable when it is capable of performing its specified safety functions. All necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication, or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) shall also be capable of performing their related support function(s).

operational readiness: the ability of a component to perform its specified functions.

overall heat-transfer coefficient: the average rate of heat transfer per unit area per unit temperature differential between the cooling and process fluids under specified fouling conditions.

Owner: the organization legally responsible for the construction and/or operation of a nuclear facility including but not limited to one who has applied for, or who has been granted, a construction permit or operating license by the regulatory authority having lawful jurisdiction.

parameter: a measured quantity (i.e., temperature, pressure, or flow) used in calculating a test result.

precision error: the closeness of agreement between repeated independent measurements of a single parameter.

precision index: the sample standard deviation based on N measurements.

preservice test: a test performed during the period after completion of construction activities related to the component and before first electrical generation by nuclear heat or in an operating plant before the component is initially placed in service.

process fluid: any fluid that supplies the heat to the heat exchanger.

required action limit: that value of heat exchanger performance such that, if corrective actions are not performed prior to the next scheduled test or monitoring, the system operability limit would be exceeded.

result sensitivity: the actual change in a result due to changing the measurement parameter by its measurement error.

system operability limit: the minimum thermal performance required of a heat exchanger so as to ensure the operational readiness of its system.

temperature effectiveness: the ratio of the temperature change of the tube side fluid to the difference between the two fluid inlet temperatures (sometimes called temperature efficiency). For plate-type heat exchangers, the cooling fluid side can be considered as the tube side.

temperature of interest: a temperature that is chosen to be monitored because of its dependency on the thermal performance of a heat exchanger.

test conditions: the conditions experienced by a heat exchanger undergoing a test.

testing method: a method that is used to quantitatively evaluate heat exchanger thermal performance.

test point: the set of parameters retrieved from the heat exchanger at a specific test condition.

test result: a value calculated from a number of parameters.

total uncertainty: the estimated error limit of a test result for a given coverage. Total uncertainty results from the propagation of measurement errors and correlational uncertainties through a calculational process and is statistically applied to the test result.

transport delay: the time required for the process fluid to travel between the heat exchanger and the point of measurement.

3 REFERENCES

3.1 Standard References

The following is a list of publications referenced in this Part. Consult the latest edition available.

(a) Standard for Power Plant Heat Exchangers; Publisher: Heat Exchange Institute, Inc. (HEI), 1300 Sumner Avenue, Cleveland, OH 44115

(b) Standards of Tubular Exchanger Manufacturers Association; Publisher: Tubular Exchanger Manufacturers Association, Inc. (TEMA), 25 North Broadway, Tarrytown, NY 10591

3.2 Appendix References

In addition to the standard references, the following additional references were used in preparing the Appendix to this Part. Consult the latest edition available.

(a) K. P. Singh, "A Method to Quantify Heat Duty Derating Due to Inter-Pass Leakage in Bolted Cover Heat Exchangers," Heat Transfer Engineering, Vol. 4, No. 314.

(b) K. P. Singh and A. I. Soler, Mechanical Design of Heat Exchangers and Pressure Vessel Components (1984; Chapters 4 and 12); Publisher: Arcturus Publishers, Cherry Hill, NJ.

(c) K. P. Singh, Theory and Practice of Heat Exchanger Design (Chapter 9); Publisher: Arcturus Publishers, Cherry Hill, NJ.

(d) N. Stambaugh, W. Closser, and F. J. Mollerus, EPRI Report NP-7552, Heat Exchanger Performance Monitoring Guidelines; Publisher: Electric Power Research Institute (EPRI), 3420 Hillview Avenue, Palo Alto, CA 94304.

(e) ASME Steam Tables, 5th edition (1983); Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(f) Cameron Hydraulic Data, 16th edition (1984); Publisher: Ingersoll-Rand Company.

(g) ASME Boiler and Pressure Vessel Code, Section II, Materials, Part D: Properties, Table TCD (1992); Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(h) R. A. Bowman, A. C. Mueller, and W. M. Nagle, "Mean Temperature Difference in Design," ASME Transactions (May 1940): 283–294 [use for single and multipass shells, even tube passes]; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(i) F. K. Fischer, "Mean Temperature Difference Correction in Multipass Exchangers," Industrial and Engineering Chemistry, Vol. 30, (1938): 377–383 [use for single and multipass shells, odd tube passes].

(j) L. Jaw, "Temperature Relations in Shell and Tube Exchangers Having One-Pass Split-Flow Shells," ASME Transactions, Journal of Heat Transfer (August 1964): 408–416 [use for divided flow shells]; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(k) K. P. Singh and M. J. Holtz, "A Comparison of Thermal Performance of Two and Four Pass Designs for Split Flow Shells," ASME Transactions, Journal of Heat Transfer, Vol. 103, No. 1 (February 1981): 169–172 [use for split flow shells]; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(l) F. J. L. Nicole, "Exchanger Design: A General Approximate Explicit Equation," ASME Transactions, Journal of Heat Transfer (February 1975): 5–8 [use for crossflow shells]; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(m) R. C. Lord, P. E. Minton, and R. P. Slusser, "Design of Heat Exchangers," Chemical Engineering (January 26, 1970): 96–116; Publisher: McGraw-Hill.

(n) ASME PTC 19.1-1998, Test Uncertainty; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990.

(o) H. W. Coleman and W. G. Steele, Experimentation and Uncertainty Analysis for Engineers (1989); Publisher: John Wiley & Sons.

(p) A Mathematical Model for Assessing the Uncertainties of Instrumentation Measurements for Power and Flow of PWR Reactors, NUREG/CR-3659 (1985).

(q) H. S. Bean, ed., Fluid Meters: Their Theory and Application (1971).

(r) AMCA 99 Standard, Fan Application Manual, Part 3: A Guide to the Measurement of Fan-System Performance in the Field (1986); Publisher: Air Moving and Conditioning Association (AMCA).

(s) HVAC Systems: Testing, Adjusting, and Balancing (1983); Publisher: Sheet Metal and Air Conditioning Contractors' National Association.

(t) ASHRAE Handbook of Fundamentals (1989); Publisher: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE), 1791 Tullie Circle, NE, Atlanta, GA 30329.

(u) National Standard for Testing and Balancing Heating, Ventilating, and Air Conditioning Systems, 5th edition (1989); Publisher: American Air Balance Council (AABC).

4 SELECTION AND PRIORITIZATION OF HEAT EXCHANGERS

4.1 Heat Exchanger Selection

Those heat exchangers required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident, shall be selected for testing or monitoring, based on individual plant design basis. For the purposes of this Part, steam generators shall be excluded from the selection process.

4.2 Heat Exchanger Prioritization

Heat exchangers selected in para. 4.1 shall be prioritized for testing or monitoring based on the criteria of paras. 4.2.1 through 4.2.3. These criteria shall be progressively applied according to the interval defined in para. 5.4 to ensure that the requirement of para. 4.1 is met.

4.2.1 Fouling Potential. If a heat exchanger is served by a fluid that has a high potential for fouling, then that heat exchanger should be given high priority.

CAUTION: **For plate heat exchangers, even under similar service conditions, differences in flow distribution due to variations of plate pattern design may result in different fouling tendencies.**

4.2.2 System Configuration. If there are two or more heat exchangers in parallel and all are subjected to essentially identical service conditions (i.e., essentially all the same flow rates and heat loads, none stagnant for long periods of time), then only one of the heat exchangers needs to be given high priority initially. For identical heat exchangers in series, the first one in the series (as defined by the fouling fluid) should be given high priority initially, as it would be expected to collect the majority of fouling deposits. If, however, the heat loads for either parallel or series configurations are not identical, then the one with the highest heat load should be given high priority.

CAUTION: **If heat exchanger geometries and tube plugging levels are different, then tube velocities should be compared as part of the prioritization process. Also, if the fouling fluid is on the shell side, even if the heat exchangers are identical, there is less predictability of individual heat exchanger performance due to potential structural problems and nonuniform fouling.**

4.2.3 Thermal Performance. If there is reason to believe that a heat exchanger is experiencing thermal performance degradation (possibly due to structural or mechanical problems), then the suspect heat exchanger should be given high priority.

5 BASIC REQUIREMENTS

5.1 Program Requirements

A program shall be established to ensure the operational readiness of the heat exchangers covered by this Part. This program shall consist of testing or monitoring (or both), trending, establishing intervals and acceptance criteria, performing uncertainty analysis and corrective actions, and maintaining appropriate records and supporting documentation. While testing is preferred, monitoring may be used instead if sufficient technical justification can be shown that testing is not feasible.

This program should incorporate periodic reviews in which the test or monitoring methods and intervals are evaluated to be the most appropriate for use in meeting the intent of this Part and such that required action limits are not exceeded. These reviews should consider advances in testing and monitoring technologies, operating histories of the heat exchangers, fouling rates, changes in cooling fluid quality, heat load availability, and previous test or monitoring results.

5.2 Preservice Requirements[1]

Preservice testing or monitoring shall be performed on a heat exchanger in the clean condition prior to or after installation in the plant.

Preservice testing or monitoring provides data and results that should be used to establish a preservice baseline for comparing with future inservice testing or monitoring results. Preservice testing or monitoring should be used to compare the as-designed heat exchanger data provided by the vendor with the as-built heat exchanger.

The preservice testing or monitoring method selected should be the same as the inservice testing or monitoring method. However, if the preservice testing or monitoring method is different than the inservice testing or monitoring method (i.e., a preservice testing or monitoring method may be chosen specifically just to verify as-built characteristics), then the inservice testing or monitoring method shall also be performed as a part of, or in conjunction with, the preservice testing or monitoring method. This will provide a preservice baseline for comparing with future inservice testing or monitoring results.

5.3 Inservice Requirements

Inservice testing or monitoring shall be performed to satisfy the program requirements of para. 5.1.

Inservice testing or monitoring shall be performed prior to performing any corrective action that would impact the thermal performance of the heat exchanger (i.e., cleaning) to determine the "as-found" condition of the heat exchanger. This "as-found" condition is essential for establishing appropriate testing or monitoring intervals.

Inservice testing or monitoring should be conducted as soon as practicable following corrective action, unless the effectiveness of the corrective action has been documented to be consistently repeatable.

Baseline inservice testing or monitoring shall be performed as soon as practicable following structural

[1] The requirements of para. 5.2 are applicable only during the period of time as specified in the definition of preservice test (see section 2).

changes (excluding minor tube plugging) that make significant permanent changes to the thermal characteristics of the heat exchanger (i.e., modifying baffle plates). This baseline inservice testing or monitoring shall be conducted on a clean heat exchanger to provide a comparison with future inservice testing or monitoring results.

5.4 Interval Requirements

Testing or monitoring intervals shall be established such that the required action limits are not exceeded (see para. 9.3 and Fig. 1). If the testing or monitoring interval [I (test) in Fig. 1] exceeds the maximum testing or monitoring interval, which assumes no corrective actions are performed [I (max.) in Fig. 1], then corrective action shall be taken.

Intervals shall be established based on preservice (or baseline inservice) testing or monitoring and subsequent inservice testing or monitoring.

Intervals shall be adjusted as part of the program review, based on fouling rate, type of fouling, operational requirements, heat load availability, etc., to guarantee satisfactory performance during the interval.

Intervals shall not exceed 10 yr.

6 SELECTION OF METHODS

The appropriate testing or monitoring method shall be selected for each heat exchanger in the program.

If test methods are chosen, they may be supplemented with monitoring methods performed between the tests. Monitoring methods may also be used to help determine the need for testing.

Selection of the testing and monitoring methods should be made by assessing their respective inclusion and exclusion criteria, additional criteria related to testing and monitoring conditions (see section 7), and errors, sensitivities, and uncertainties (see section 8). The criteria for each method should be applied to each of the heat exchangers selected until, through the process of elimination, the most appropriate method is selected (see Fig. 2).

While the testing and monitoring methods presented here should cover the majority of applications, there is no intent to limit the program to these methods if more appropriate testing and monitoring methods are devised for particular applications.

6.1 Functional Test Method

6.1.1 Objective. The objective of the functional test method is to provide an indication of thermal performance degradation of a heat exchanger over time by measuring a temperature that is dependent on the thermal performance of the heat exchanger and to compare that temperature with established acceptance criteria (see section 9).

6.1.2 Descriptive Summary. The functional test method will demonstrate directly that the heat exchanger is capable of meeting its acceptance criteria (see section 9). It is applied to the temperature of the component or area that the heat exchanger is designed to cool (the "temperature of interest") rather than to the temperatures into or out of the heat exchanger itself. Examples of temperatures of interest are motor or pump-bearing temperatures, bearing oil temperatures, pump room temperatures, and diesel jacket water temperatures.

After meeting the inclusion and exclusion criteria, the temperature of interest is then measured and compared to the acceptance criteria for that heat exchanger. A typical example is presented in Nonmandatory Appendix C of this Part, para. C-1.

6.1.3 Inclusion Criteria. The functional test method shall be considered if

(a) the acceptance criteria (see section 9) of the heat exchanger is stated explicitly in terms of a "temperature of interest" (i.e., motor stator temperature for a motor cooler)

(b) design accident flows and inlet temperatures can be achieved during test conditions[2]

(c) the heat exchanger can be subjected to the same (or greater) heat load that would be present under the accident conditions (i.e., for a pump room cooler, the pumped fluid temperature, any ventilation function, and the motor load should be as they would be under the accident condition)

(d) steady-state conditions (see para. 7.1) do exist

6.1.4 Exclusion Criteria. There are no exclusion criteria for the functional test method.

6.1.5 Required Parameter. The temperature of interest shall be measured to quantitatively evaluate the heat exchanger thermal performance using the functional test method.

NOTE: The component of interest must be functioning within the design basis during testing to ensure this method accurately represents heat exchanger performance.

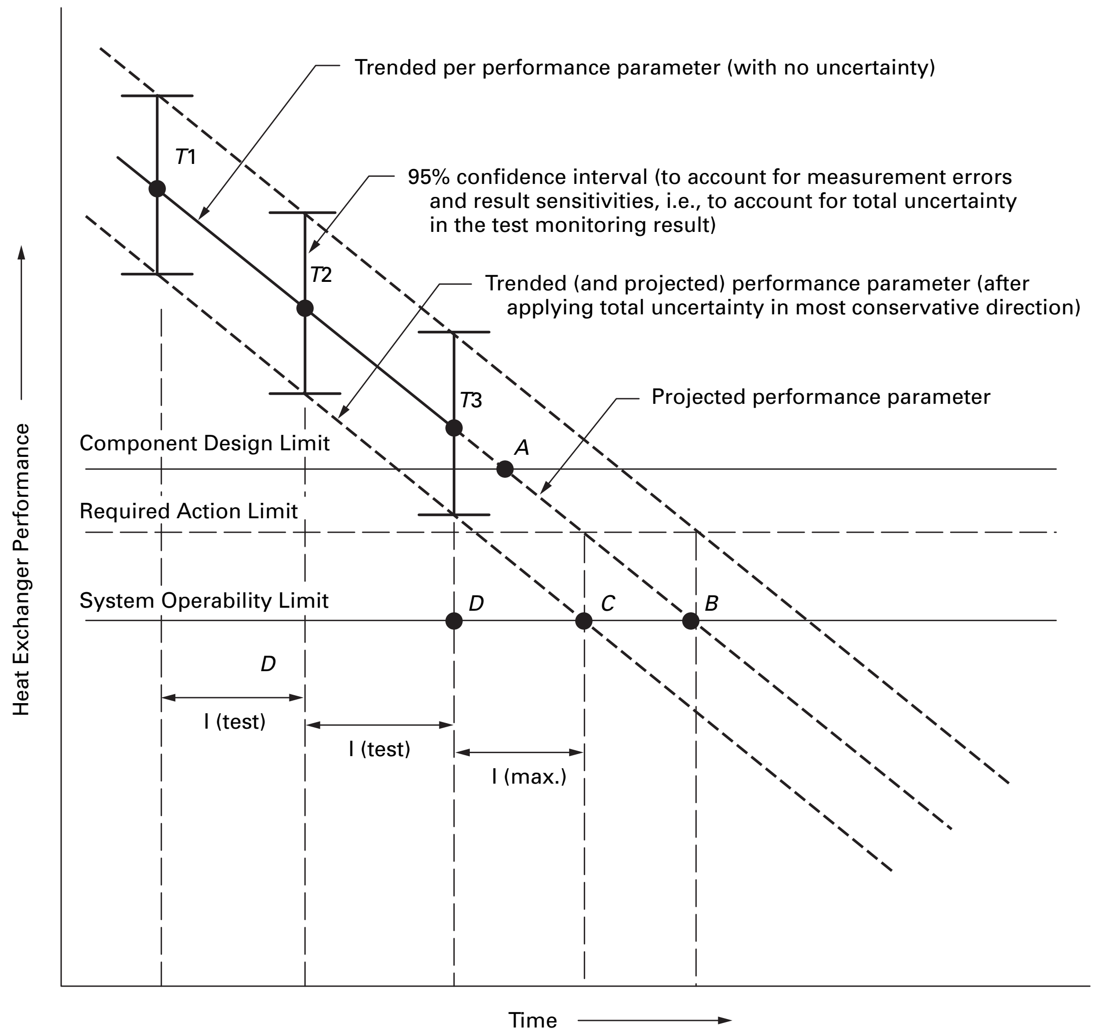
6.2 Heat-Transfer Coefficient Test Method (Without Phase Change)

6.2.1 Objective. The objective of the heat-transfer coefficient test method (without phase change) is to determine the heat-transfer capability of a heat exchanger when a phase change is not occurring at test conditions.

6.2.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the

[2] When operational restrictions prohibit the establishment of design accident condition equipment heat load or process inlet temperature for the conduct of this test, an equivalent heat load may be applied by the use of portable heaters or other similar means.

Fig. 1 Intervals, Limits, and Parameter Trending (Typical)



LEGEND:

I (test) = historical test or monitoring interval

I (max.) = maximum test or monitoring interval if no corrective actions are performed. If I (max.) < I (test) then corrective action shall be taken

$T1, T2, T3$ = successive test or monitoring data points

$T3$ = latest test or monitoring data point

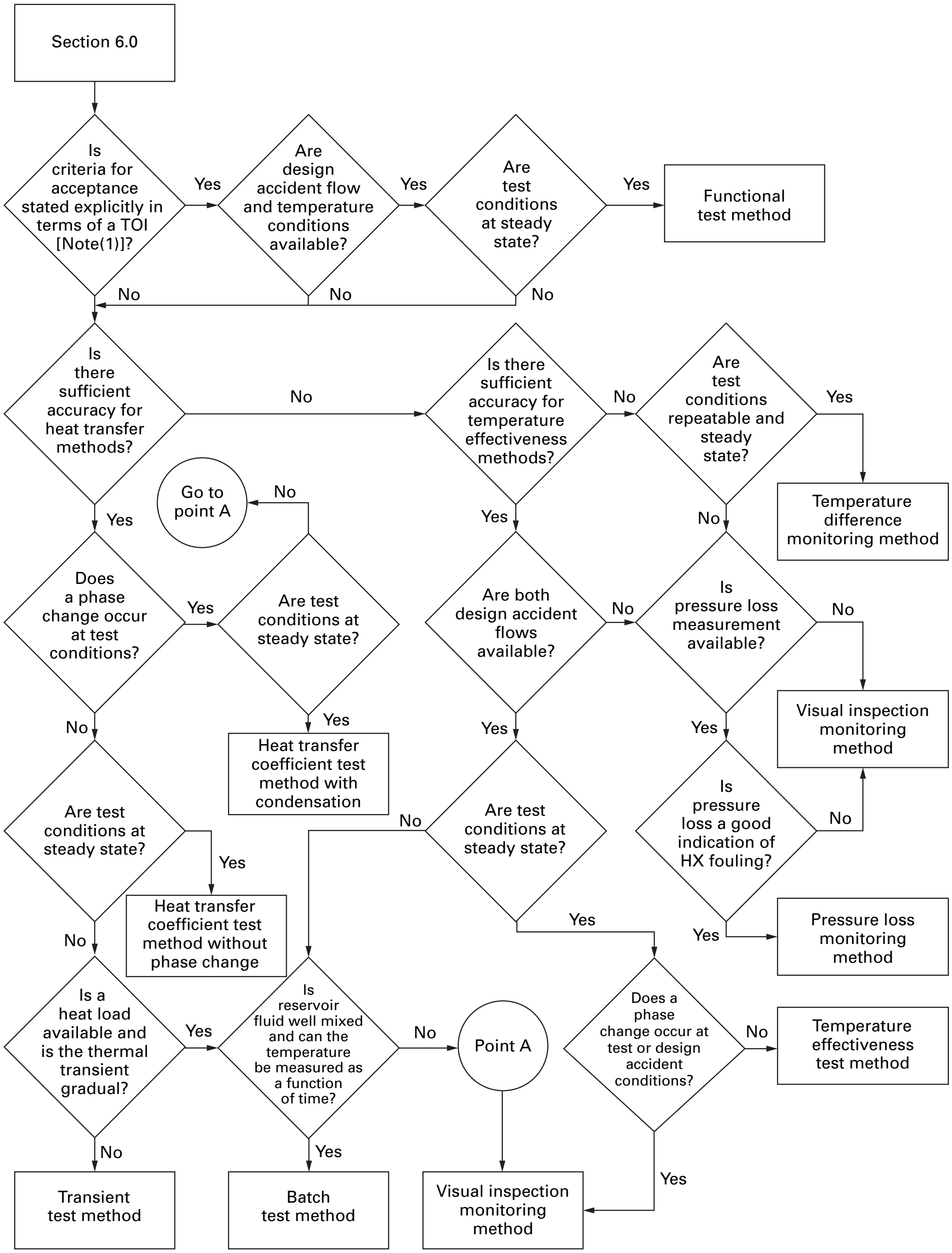
A = heat exchanger unable to satisfy requirements specified on component data sheet (with no uncertainty)

B = heat exchanger unable to satisfy requirements for operational readiness (with no uncertainty)

C = heat exchanger unable to satisfy requirements for operational readiness (after accounting for total uncertainty by applying 95% confidence interval in most conservative direction)

$T3 - D$ = current “absolute” operating margin (with no uncertainty)

Fig. 2 Method Selection Chart



NOTE:
(1) Temperature of interest.

required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C of this Part, section C-2) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

6.2.3 Inclusion Criteria. The heat-transfer coefficient test method (without phase change) shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see section 9) in terms of heat duty (Btu/hr)

(b) sufficient accuracy (in accordance with section 8) is achievable at test conditions

(c) a phase change does not occur at test conditions

(d) steady-state conditions (see para. 7.1) do exist

6.2.4 Exclusion Criteria. The heat-transfer coefficient test method (without phase change) shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6)

(b) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available; see para. 5.4 and section 9)

6.2.5 Required Parameters. At least five of the following six parameters [subparas. (a) through (f)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the heat-transfer coefficient test method (without phase change). The sixth parameter may be calculated from the other five (see para. 8.5). The accuracy of the calculated parameter depends on the accuracy of the other five parameters (see section 8).

(a) cooling fluid inlet temperature

(b) cooling fluid outlet temperature

(c) process fluid inlet temperature

(d) process fluid outlet temperature

(e) cooling fluid flow rate

(f) process fluid flow rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.3 Heat-Transfer Coefficient Test Method (With Condensation)

6.3.1 Objective. The objective of the heat-transfer coefficient test method (with condensation) is to determine the heat-transfer capability for heat exchangers having condensation from steam-air mixtures (e.g., air coolers or air-to-water heat exchangers) during test conditions.

6.3.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C of this Part, section C-3) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

6.3.3 Inclusion Criteria. The heat-transfer coefficient test method (with condensation) shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see section 9) in terms of heat duty (Btu/hr)

(b) sufficient accuracy (in accordance with section 8) is achievable at test conditions

(c) condensation occurs during the test conditions

(d) steady-state conditions (see para. 7.1) do exist

6.3.4 Exclusion Criteria. The heat-transfer coefficient test method (with condensation) shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6)

(b) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available, see para. 5.4 and section 9)

6.3.5 Required Parameters. At least seven of the following 10 parameters [subparas. (a) through (j)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the heat-transfer coefficient test method (with condensation). Measurement of the following parameter in subpara. (a) is required:

(a) process fluid (steam-air mixture) pressure

In addition, at least five of the following six parameters [subparas. (b) through (g)] shall be measured. The sixth parameter may be calculated from the other five (see para. 8.5). The accuracy of the calculated parameter will depend on the accuracy of the other five parameters (see section 8).

(b) cooling fluid inlet temperature

(c) cooling fluid outlet temperature

(d) process fluid (steam–air mixture) inlet temperature

(e) process fluid (steam–air mixture) outlet temperature

(f) cooling fluid flow rate

(g) process fluid (steam–air mixture) flow rate

In addition to the above, any one of the following three parameters [subparas. (h) through (j)] is required:

(h) process fluid (steam–air mixture) inlet relative humidity

(i) process fluid (steam–air mixture) outlet relative humidity

(j) process fluid (steam–air mixture) condensation rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.4 Transient Test Method

6.4.1 Objective. The objective of the transient test method is to determine the thermal performance of a heat exchanger when steady-state conditions (see para. 7.1) cannot be achieved during the test.

6.4.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (an example is presented in Nonmandatory Appendix C of this Part, section C-4) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

The transient test method refers to measuring the time it takes for temperatures to change in response to a transient heat load being placed on the heat exchanger. The transient test method may be used where flow rates or inlet temperatures (or both) vary during the test. An example would be the cooling of the component cooling water loop after its initial temperature has been allowed to increase temporarily by stopping the cooling water flow to the component cooling water heat exchanger.

6.4.3 Inclusion Criteria. The transient test method shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see section 9) in terms of heat duty (Btu/hr)

(b) sufficient accuracy (in accordance with section 8) is achievable at test conditions

(c) an appreciable heat load is available such that the temperature of the process fluid can be raised temporarily

(d) a phase change does not occur at test conditions

6.4.4 Exclusion Criteria. The transient test method shall not be considered if

(a) the transient is a steep function of time, such that the thermal inertia of the heat exchanger becomes significant ["steep" being defined as the left sides of inequalities (1) through (3) in para. 7.1 being $>0.25Q$]

(b) the value of thermal inertia (per para. 7.1) cannot be calculated

(c) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6)

(d) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available, see para. 5.4 and section 9)

(e) significant condensation occurs at the test conditions

6.4.5 Required Parameters. At least seven of the following eight parameters [subparas. (a) through (h)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the transient test method. Measurement of the following six parameters [subparas. (a) through (f)] is required:

(a) cooling fluid inlet temperature time history

(b) process fluid inlet temperature time history

(c) cooling fluid flow rate time history

(d) process fluid flow rate time history

(e) cooling fluid initial temperature profile inside the heat exchanger

(f) process fluid initial temperature profile inside the heat exchanger

In addition, at least one of the following two parameters [subparas. (g) and (h)] shall be measured:

(g) cooling fluid outlet temperature time history

(h) process fluid outlet temperature time history

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.5 Temperature Effectiveness Test Method

6.5.1 Objective. The temperature effectiveness test method is used to predict the effectiveness of the heat exchanger at a known reference point (design accident condition, design point, test point, established using the heat-transfer coefficient test method). This method assumes that the process and cooling fluid mass flow rates at the test point are essentially the same as those at the reference point (within ±5%). This test method is accomplished by collecting the process and cooling fluid inlet and outlet temperatures at the test point, choosing two temperatures at the reference point, and calculating the remaining two temperatures at the reference point.

6.5.2 Descriptive Summary. The temperature effectiveness is the ratio of the temperature change of the tube-side fluid to the difference between the two fluid inlet temperatures (sometimes called temperature efficiency). For plate-type heat exchangers, the cooling fluid side may be considered to be the tube side.

NOTE: The temperature effectiveness is defined with respect to the tube-side terminal difference in the foregoing. Alternatively, the effectiveness may be defined with respect to the shell-side terminal difference; perform all required calculations in a consistent manner.

After meeting the inclusion and exclusion criteria and measuring the required parameters, the temperatures that are measured are applied using a methodology (a typical example is presented in Nonmandatory Appendix C of this Part, section C-5) that will result in the determination of two of the four temperatures at the known reference point, which can then be compared with the acceptance criteria. This method is conservative if the design accident condition temperatures are higher than the test condition temperatures because of the improved heat-transfer coefficient at higher temperatures.

6.5.3 Inclusion Criteria. The temperature effectiveness test method shall be considered if

(a) sufficient accuracy (in accordance with section 8) is achievable at test conditions

(b) both test flows can be manipulated to within ±5% of the design accident flows

(c) design accident temperatures cannot be achieved during test conditions (e.g., for pump room coolers)

(d) steady-state conditions (see para. 7.1) do exist

6.5.4 Exclusion Criteria. If a phase change is expected to occur at either the test or known reference point, then the temperature effectiveness test method shall not be considered.

6.5.5 Required Parameters. Six of the following eight parameters [subparas. (a) through (h)] shall be used to quantitatively evaluate the heat exchanger thermal performance using the temperature effectiveness test method. Measurement of the following four parameters [subparas. (a) through (d)] is required:

(a) cooling fluid inlet temperature at test conditions

(b) cooling fluid outlet temperature at test conditions

(c) process fluid inlet temperature at test conditions

(d) process fluid outlet temperature at test conditions

In addition, only two of the following four parameters [subparas. (e) through (h)] shall be chosen:

(e) cooling fluid inlet temperature at the reference point

(f) cooling fluid outlet temperature at the reference point

(g) process fluid inlet temperature at the reference point

(h) process fluid outlet temperature at the reference point

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.6 Batch Test Method

6.6.1 Objective. The objective of the batch test method is to determine the temperature effectiveness and the overall heat-transfer coefficient of a heat exchanger by measuring the aggregate quantity of heat removed by the heat exchanger in the batch mode from a source of large thermal capacity (process fluid reservoir). It provides an alternative to the previous test methods when steady-state test conditions (see para. 7.1) cannot be achieved.

The batch test method is accomplished by measuring the initial process fluid and final process fluid reservoir temperatures over a measured time period, while holding the cooling fluid inlet temperature constant. Using the thermal capacity of the process fluid reservoir, the temperature effectiveness and the overall heat-transfer coefficient can be calculated.

NOTE: The description presented herein assumes the reservoir to contain the process fluid. The test and the calculational procedures will remain valid if the reverse condition exists (i.e., a cool reservoir is being heated by the process fluid).

6.6.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C of this Part, section C-6) that will result in the determination of the temperature effectiveness and the overall heat-transfer coefficient of the heat exchanger.

6.6.3 Inclusion Criteria. The batch test method shall be considered if

(a) sufficient accuracy (in accordance with section 8) is achievable at test conditions

(b) the temperature of the process fluid reservoir can be measured as a function of time

(c) the fluid in the process fluid reservoir is well mixed

(d) the heat exchanger is the sole medium for the enthalpy change in the process fluid reservoir during the test

(e) steady-state conditions (see para. 7.1) do not exist

6.6.4 Exclusion Criteria. The batch test method shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6)

(b) the fouling rate of the heat exchanger is such that the overall heat transfer of the heat exchanger is changed during the test

(c) the fluid in the process fluid reservoir undergoes a phase change

(d) the flow rate or inlet temperature of the cooling fluid is subject to variation during the test

6.6.5 Required Parameters. The following six parameters [subparas. (a) through (f)] shall be determined to quantitatively evaluate the heat exchanger thermal performance using the batch test method. These six parameters are required to calculate the temperature effectiveness.

(a) mass of the process fluid

(b) initial process fluid inlet temperature

(c) final process fluid inlet temperature

(d) time required to cool the process fluid

(e) cooling fluid flow rate

(f) cooling fluid inlet temperature

In addition, to calculate the overall heat-transfer coefficient, the following parameter in subpara. (g) shall be measured:

(g) process fluid flow rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.7 Temperature-Difference Monitoring Method

6.7.1 Objective. The objective of the temperature-difference monitoring method is to provide an indication of thermal performance degradation of a heat exchanger over time by monitoring the relationship between the temperature of interest and the inlet temperature of the cooling fluid.

6.7.2 Descriptive Summary. In certain applications, where the heat exchanger coolant temperatures fluctuate (e.g., due to seasonal fluctuations in cooling fluid temperature), an indication of heat exchanger thermal performance may be obtained by monitoring the temperature of interest and the exchanger cooling fluid inlet temperature. With accumulated operating experience, a correlation between these temperatures may be established that permits detection of changes in exchanger performance through comparison of results from successive tests.

After meeting the inclusion and exclusion criteria and measuring the required parameters, the temperature of interest and the cooling fluid inlet temperature are measured. Deviation of the measured temperature difference from that predicted by the correlation for the measured cooling fluid inlet temperature provides an indication of heat exchanger performance change. An example is presented in Nonmandatory Appendix C of this Part, section C-7.

6.7.3 Inclusion Criteria. The temperature difference monitoring method shall be considered if

(a) the equipment loads and the process temperatures and flows that create the heat load of the heat exchanger of interest are of the same magnitude for each test in the series

(b) heat load and flows can be repeatedly attained for each test in a series of tests

(c) steady-state conditions (see para. 7.1) do exist

6.7.4 Exclusion Criteria. If the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required), then temperature difference monitoring method shall not be considered.

6.7.5 Required Parameters. The following two parameters [subparas. (a) and (b)] shall be measured to indirectly evaluate the heat exchanger thermal performance using the temperature difference monitoring method:

(a) cooling fluid inlet temperature

(b) temperature of interest

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.8 Pressure-Loss Monitoring Method

6.8.1 Objective. The objective of the pressure-loss monitoring method is to monitor the pressure loss across a heat exchanger, corrected for flow conditions.

6.8.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C of this Part, section C-8) that will result in the calculation of a pressure loss, corrected to the acceptance criteria flow rate, for comparison with an acceptance criteria at that same flow condition.

Increases in pressure loss observed in a trend can be used as an indicator of the onset of flow blockage and thus as an aid in determining inspection and cleaning frequencies (refer to para. 6.10 and Nonmandatory Appendix C of this Part, section C-10). If the heat exchanger is of the plate and frame type, this method may be the most sensitive for monitoring performance.

Even if heat loads are available, when fouling rates are high, pressure loss monitoring may provide a simple way to monitor fouling without having to frequently perform heat-transfer analysis.

6.8.3 Inclusion Criteria. The pressure loss monitoring method shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see section 9) explicitly in terms of pressure loss

(b) the correlation between pressure loss and heat transfer is known

(c) the fouling characteristics (see Nonmandatory Appendix B of this Part, section B-11) are likely to create a flow restriction

6.8.4 Exclusion Criteria. The pressure loss monitoring method shall not be considered if

(a) the heat exchanger fouling layer thickness is small so as to preclude pressure loss from providing a reliable indication of heat exchanger capability

(b) the fluid being monitored is a liquid on the shell side of a heat exchanger

(c) the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required)

(d) the flow rate on the tube side traverses flow regimes in going from the test flow rate to the acceptance criteria flow rate

6.8.5 Required Parameters. The following two parameters [subparas. (a) and (b)] shall be measured to indirectly evaluate the heat exchanger thermal performance using the pressure-loss monitoring method:

(a) the monitored fluid flow rate

(b) the monitored fluid pressure loss

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.9 Visual Inspection Monitoring Method

6.9.1 Objective. The objective of the visual inspection monitoring method is to determine the condition of the component in relation to its ability to transfer heat.

6.9.2 Descriptive Summary. This method assumes that the heat exchanger being inspected will perform its intended function if it is maintained within a preestablished acceptably clean condition. After meeting the inclusion and exclusion criteria and measuring the required parameters, the heat exchanger is inspected (typical inspection types and techniques are presented in Nonmandatory Appendix C of this Part, section C-9) and the ability of the heat exchanger to meet its acceptance criteria is evaluated based on the as-found condition of the component.

The visual inspection monitoring method consists of visually inspecting the heat exchanger periodically, usually by disassembly, allowing access to the internals of the cooling fluid and process fluid sides. Also, corrective action (e.g., cleaning) or additional inspections (e.g., eddy current testing or other NDE to determine integrity) can be implemented based on the inspection results. The inspection interval can be adjusted, based on experience.

6.9.3 Inclusion Criteria. The visual inspection monitoring method shall be considered if

(a) it is not possible to test or monitor by one of the previously described methods.

(b) there is sufficient access to the heat exchanger, such that the evaluator is able to cover a representative sample of the heat exchanger surface on the side most likely to foul.

(c) it is understood by those doing the inspections that the thickness of many biofilm layers is significantly reduced when they are in a dry condition and the layers can appear deceptively thin during an inspection when in fact they may be significantly thicker in their normal wet condition. Even wet fouling layers of only a few thousandths of an inch can cause significant degradation in heat transfer. These thicknesses would become even more difficult to detect in their dry condition.

(d) a preestablished acceptably clean condition exists to which the "fouled" observation may be compared (since a visual inspection cannot quantitatively evaluate heat exchanger performance).

6.9.4 Exclusion Criteria. The visual inspection monitoring method shall not be considered if

(a) unacceptable fouling would not be readily detectable by visual inspection (i.e., biofilms or very low allowable fouling resistances)

(b) the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required)

6.9.5 Required Parameters. Although no specific parameters are required for the inspection monitoring method, some inspection techniques may monitor certain parameters. For a discussion of typical inspection types and techniques, refer to Nonmandatory Appendix C of this Part, section C-9.

6.10 Parameter Trending

6.10.1 Objective. The objective of parameter trending is to provide a systematic method for tracking heat exchanger performance over time and to provide a tool for predicting the need for remedial action.

Parameter trending shall be used to help establish appropriate intervals and acceptance criteria, and to supplement the testing and monitoring methods described in paras. 6.1 through 6.9.

6.10.2 Descriptive Summary. Parameter trending uses the results from one or more of the test or monitoring methods described in paras. 6.1 through 6.9. In addition, other parameters may be trended. The measured or calculated heat exchanger performance parameters are trended to determine a projected rate of performance degradation (see Fig. 1). The time to the next required corrective action, and changes in the rate of performance degradation that may indicate the onset of operational problems, may be readily detected through parameter trending.

After selecting the parameters to be trended (see Nonmandatory Appendix C of this Part, section C-10) and trending these parameters for a minimum of three test or monitoring points, the trended parameters are compared to the applicable acceptance criteria (refer to section 9 and Fig. 1). Typical trendable parameters are presented in Nonmandatory Appendix C of this Part, section C-10.

7 TESTING AND MONITORING CONDITIONS

7.1 Steady State

Steady state as defined here is applicable to the following test and monitoring methods:

(a) functional test method using inequality (1) below

(b) heat-transfer coefficient test method without phase change using inequalities (1) through (3) below

(c) heat-transfer coefficient test method with condensation using inequalities (1) through (3) below, but expressed in terms of enthalpy

(d) temperature effectiveness test method using inequality (1) below

(e) temperature difference monitoring method using inequality (1) below

For all other test and monitoring methods, steady state is not required.

Flows and temperatures should be held constant throughout the duration of the test to minimize precision errors (see para. 8.1.2), to minimize errors associated with sensor response times, and to allow the heat exchanger time to reach steady-state conditions.

A steady state exists when the transient part of the heat duty is very small when compared to the total heat duty defined as

$$\left[\sum_i (M_i)(C_i)\right][(\Delta T_{ave})/(\Delta\tau)] \ll Q \qquad (1)$$

and the fluid flow on both the cooling fluid and process fluid sides has reached a steadiness defined as

$$[T_1 - T_2][\Delta(WC)_{shell}] \ll Q \qquad (2)$$

$$[t_1 - t_2][\Delta(WC)_{tube}] \ll Q \qquad (3)$$

CAUTION: The application of time-independent analysis techniques (i.e., steady-state methods) to time dependent (i.e., transient) conditions will result in invalid analyses. If steady-state conditions cannot be achieved or adequately determined, an alternative testing or monitoring method should be considered.

NOTE: The variation in the total heat duty should be sufficiently small to ensure that steady-state conditions exist for a given application. Experience has shown that variation in total heat duty of 3.0% or less, when applied to inequalities (1) through (3), will result in conditions that adequately approximate steady state for current analytical models. Determining the rate of change of T_{ave} for variation in the total heat duty does not require the use of highly accurate instruments. Statistical techniques may be used to evaluate the difference between a series of points over time. This evaluation of the difference will negate the bias inherent to the instrument string being employed (see NOTE in Nonmandatory Appendix C of this Part, para. C-11.1.1). The precision required to meet accuracies of 3.0% or less in the total heat duty can then be achieved by increasing the number of data sets taken (see Nonmandatory Appendix C of this Part, para. C-11.1.2).

These inequalities must be continuously satisfied for a time period greater than $\tau 1$,

where

C_i = specific heat of material of i^{th} energy storage element, Btu/lbm-°F
M_i = mass of i^{th} energy storage element (i.e., tubes, shell, water) in the heat exchanger, lbm
Q = minimum of average bulk heat transfer rate calculated using the following two steady-state formulas, Btu/sec:
$$Q = |(WC)_{shell}(T_1 - T_2)|$$
$$Q = |(WC)_{tube}(t_1 - t_2)|$$
T_1 = shell-side inlet temperature during time period $\tau 1$, °F
t_1 = tube-side inlet temperature during time period $\tau 1$, °F
T_2 = shell-side outlet temperature during time period $\tau 1$, °F
t_2 = tube-side outlet temperature during time period $\tau 1$, °F
T_{ave} = instantaneous average of both inlet and both outlet temperatures, °F; if only three temperatures are measured then the fourth temperature should be calculated using the steady-state equations
$(WC)_{shell,\ min}$ = minimum value of the product of the shell-side mass flow rate and specific heat during time interval $\tau 1$
$(WC)_{tube,\ min}$ = minimum value of the product of the tube-side mass flow rate and specific heat during time interval $\tau 1$
ΔT_{ave} = change in T_{ave} over $\Delta\tau$ time, °F
$\Delta(WC)_{shell}$ = change in the product of shell-side mass flow rate and specific heat during time interval $\Delta\tau$, Btu/°F-sec
$\Delta(WC)_{tube}$ = change in the product of tube-side mass flow rate and specific heat during time interval $\Delta\tau$, Btu/°F-sec
$\Delta\tau$ = time interval between successive data points, sec
$\tau 1$ = ten times the maximum value of either of the following in seconds:
$$\sum_i [M_iC_i/(WC)_{shell,\ min}]$$
$$\sum_i [M_iC_i/(WC)_{tube,\ min}]$$

NOTE: The above is not applicable to situations where either fluid is undergoing a phase change.

7.2 Flow Regimes

The flow regime(s) present on both the tube and the shell side of the heat exchanger under evaluation shall be identified, during both the test and the design accident conditions.

When going from test to design accident conditions, traversal of flow regimes is acceptable, except when specifically limited or prohibited by the exclusion criteria for a specific testing or monitoring method.

If traversal of flow regimes does occur, the additional uncertainty introduced by applying the required corrections shall be properly accounted for.

CAUTION: The uncertainty associated with traversal of flow regimes on the shell side is much greater than the uncertainty associated with traversal of flow regimes on the tube side. This may significantly affect the overall accuracy of the calculated value for the thermal performance of the heat exchanger.

7.3 Temperatures

Testing shall be conducted at temperatures as close to design accident conditions as practicable to minimize the errors introduced by changes in fluid properties when extrapolating from test to design accident conditions.

8 ERRORS, SENSITIVITIES, AND UNCERTAINTIES

Statistical methods shall be employed to ensure that both measurement errors and result sensitivities are considered when calculating the total uncertainty of any test or monitoring result. Measurement errors associated with measurement parameters used as equation inputs shall be propagated through the equation to determine the sensitivity of each measurement parameter on the test or monitoring result and to determine the total uncertainty of the test or monitoring result.

The total uncertainty shall be determined every time a test or monitoring is performed, because the total uncertainty will depend significantly upon the heat load available during the test and the cleanliness of the heat exchanger during the test. In fact, the cleaner the heat exchanger is, the more sensitive the test result will be to errors in the measurement parameters. This is primarily because of the reduction in terminal temperature differences associated with a clean heat exchanger, making those differences (and thus the LMTD) more sensitive to errors in their individual temperatures.

A 95% confidence level shall be applied to the calculated result for the purpose of comparing the testing or monitoring results to the acceptance criteria. Based on the heat exchanger design values and the plant design requirements for each heat exchanger function, a "required action limit" for corrective actions shall be established (see para. 9.3 and Fig. 1).

A standard statistical method for calculating the total uncertainty in the result is presented in Nonmandatory Appendix C of this Part, para. C-11. More sophisticated statistical methods may be used, which use additional effects (i.e., nonsymmetrical error, calculational bias, and redundant measurements), to improve the accuracy of the result, provided these methods are technically justifiable.

NOTE: If the total uncertainty of the test or monitoring result is determined to be too great to allow for meaningful results (i.e., the total uncertainty is greater than the available margin), then either

(a) measurement errors should be decreased as outlined in para. 8.1 and Nonmandatory Appendix C of this Part, section C-11 or

(b) whatever actions are necessary should be taken to increase the available margin

8.1 Measurement Errors

Instrumentation accuracies used for testing and monitoring shall be such that, for each method selected, the determination of measurement errors, in conjunction with the result sensitivities, allows corrective actions to be performed so as to maintain heat exchanger operational readiness at all times. The measurement error consists of bias (fixed), precision (random), and spatial errors. A conventional method for calculating measurement errors is summarized in Nonmandatory Appendix C of this Part, section C-11.

The following considerations shall be addressed to minimize measurement errors:

(a) selection, calibration, and placement of instruments (see Nonmandatory Appendix C of this Part, section C-11)

(b) test and monitoring conditions (see section 7)

(c) instrument response times, transport delay times, and other factors (see Nonmandatory Appendices A and B of this Part)

8.2 Result Sensitivities

Result sensitivities refers to how the previously discussed measurement errors are propagated through the calculational process. These sensitivities will be influenced by the test or monitoring method selected. There are two basic methods for determining result sensitivities: analytically and numerically. Due to the complexity of calculating the partial derivatives of a heat exchanger test result (e.g., fouling factor) with respect to each of the measurement parameters (i.e., the analytical method), the numerical method is the preferred method for this application. This method (sometimes called the "numerical perturbation" method) is summarized in Nonmandatory Appendix C of this Part, section C-11.

8.3 Total Uncertainty

Total uncertainty refers to how the previously discussed result sensitivities are combined to arrive at a total uncertainty for the test or monitoring result. This total uncertainty will be influenced by the test or monitoring method selected. A method for determining the total uncertainty is summarized in Nonmandatory Appendix C of this Part, section C-11.

8.4 Calculations and Averaging

All measured parameters shall be collected (sampled) at the same time, for each test interval, to minimize errors associated with variations in test conditions that might occur during the test. After collecting the appropriate number of data sets (see Nonmandatory Appendix C of this Part, para. C-11.1.2) and after rejecting any inconsistent data, each parameter shall be averaged. The test result shall then be calculated based on these average values.

To minimize error propagation through the remainder of the calculations, if additional, nonrequired parameters are able to be measured (see section 6), the total uncertainty in the result should be calculated using both the measured and the calculated value of each parameter. A typical approach is summarized in Nonmandatory Appendix C of this Part, para. C-11.4.

8.5 Validity Check

The additional, nonrequired parameters may also be used as a validity check for the method being used (see section 6).

For example, for the heat-transfer coefficient test method (without phase change), although measurement of only five of the six parameters is required (the sixth parameter being calculated), the sixth parameter may also be measured to provide a means for validating the test by comparing the calculated value of the sixth parameter to the measured value of that same parameter. If the sixth parameter is measured, and if the calculated value does not agree with the measured value, then the difference shall be reconciled (see Nonmandatory Appendix A of this Part for potential causes).

As another example, for the heat-transfer coefficient test method (with condensation), although measurement of only one of the steam-air mixture relative humidity parameters is required, it is recommended that both relative humidity parameters be measured to provide a means for validating the test by comparison with the other relative humidity parameter.

Additional parameters may be measured, in excess of the required parameters, if desired, to use as additional validity checks.

8.6 Correlational Uncertainty

Additional uncertainty may be introduced into the test result due to the uncertainty associated with the empirical correlations used for heat-transfer film coefficients (i.e., the correlational uncertainty, typically 15% to 20%). This is especially true if the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition. However, if heat-transfer coefficients are calculated using the backcalculation method, then this uncertainty is significantly reduced. This is because any uncertainty in the correlation-based heat-transfer coefficients is corrected by the manufacturer by using an experience-based correction factor to develop the design rated duty of the heat exchanger (which reflects the heat exchanger's true performance). When this duty is used to backcalculate the heat-transfer coefficient, it will include this correction factor and, thus, more accurately reflect the true value of the heat-transfer coefficient.

9 ACCEPTANCE CRITERIA

Acceptance criteria consists of the following three types of limits:

(a) system operability limits

(b) component design limits

(c) required action limits (see Fig. 1 and section 2 for definitions)

9.1 System Operability Limits

System operability limits shall be established for each heat exchanger, in accordance with the Safety Analysis Report, safety evaluation requirements, or other design calculations.

System operability limits shall be used to establish required action limits (see para. 9.3).

Examples of system operability limits are as follows:

(a) a requirement that a prescribed amount of heat must be transferred by some combination of heat exchangers under several operating conditions

(b) a requirement that pressure loss must be maintained below a certain value at a given flow rate to ensure adequate performance

(c) a requirement (based on the intended safety function) that the temperature of a component (e.g., a bearing temperature) or an enclosed space (e.g., a pump room) being serviced by a heat exchanger be maintained below a set temperature under accident conditions

9.2 Component Design Limits

Component design limits shall be identified for each heat exchanger, in accordance with the heat exchanger specification sheet, the heat exchanger design data sheet, or other similar component design specification. This as-designed heat exchanger data should be verified to correspond to the as-built heat exchanger.

Component design limits shall be used to indicate component degradation that, although not exceeding the system operability limits, may nonetheless be of concern from a component reliability standpoint.

NOTE: System operability limits may allow either more or less component degradation than component design limits. When the system operability limits allow more component degradation than the component design limits (as depicted in Fig. 1), while system operability may not be threatened, component reliability could be threatened (refer to Nonmandatory Appendix B of this Part, section B-12). When the system operability limits allow less component degradation than the component design limits, the component design limits will serve no useful function for inservice testing (for preservice testing, see below). While no action is required for exceeding component design limits, corrective action should be taken at the next available opportunity to ensure continued component reliability.

Component design limits shall also be used during preservice testing to confirm that the component is or is not performing according to the component design limit.

Examples of component design limits are as follows:

(a) a requirement that a single heat exchanger was designed to transfer a specific amount of heat

(b) a requirement that a single heat exchanger was designed for operating with a specified pressure drop

9.3 Required Action Limits

Required action limits shall be established for each heat exchanger to allow corrective action to be taken prior to exceeding the system operability limit. Required action limits are based on the known fouling (or other degradation) rate, as determined by parameter trending (see para. 6.10), after applying a 95% confidence level to the data. This 95% confidence level is determined based on the total uncertainty calculated for the test or monitoring result (see section 8 and Fig. 1).

Required action limits shall be used to ensure heat exchanger operational readiness throughout the entire interval of testing or monitoring (see para. 5.4).

10 CORRECTIVE ACTION

Corrective action (flushing, mechanical cleaning, chemical cleaning, mechanical repair, etc.) shall be performed following failure to meet the acceptance criteria as defined in section 9, or whenever I (test) exceeds I (max.), as described in Fig. 1. As part of this corrective action, the root cause of the failure should be determined (see Nonmandatory Appendix A of this Part).

Unless the effectiveness of the corrective action has been documented to be consistently repeatable, then following the corrective action, the heat exchanger should be retested or remonitored.

Following the corrective action, the heat exchanger shall, as a minimum, be evaluated to ensure the intended results of the corrective action have been accomplished.

NOTE: This evaluation involves examining and judging the performance of, and need not involve testing or monitoring. However, if the corrective action involved cleaning the shell side of the heat exchanger, then the heat exchanger should be retested or remonitored due to the possibility that fouling or cleaning materials (or both) may have been redistributed within the shell, or on the outside of the tubes, during the cleaning process (instead of being removed). Also, if the potential exists for debris (either fouling or maintenance related) to get trapped against a tube sheet following the cleaning process, or following upstream maintenance, then the heat exchanger should be retested or remonitored following that cleaning or maintenance.

Retesting or remonitoring after corrective action may also be necessary to establish a new baseline if the corrective action changes the mechanical characteristics (and thus the heat-transfer characteristics) of the heat exchanger (i.e., tube material changes, tube sleeving, and baffle modifications).

In addition to evaluation of the heat exchanger receiving the corrective action, evaluation of other heat exchangers may be required. If the fouling (or degradation) mechanism responsible for the first failure was the "normal" or "expected" mechanism, and if it occurred at the "normal" or "expected" rate, then no further evaluation is required. If, however, the mechanism for fouling (or degradation) is discovered to be of a different nature than expected, or if the fouling (or degradation) occurred more rapidly than expected, then other heat exchangers should be evaluated according to the following priority:

(a) Evaluate those heat exchangers that are known to have the least margin.

(b) Evaluate those heat exchangers that are likely to have been subject to the same fouling (or degradation) mechanism.

(c) Evaluate those heat exchangers that are next on the existing schedule.

11 RECORDS AND RECORD KEEPING

11.1 Equipment Records

A record shall be maintained that contains the following information for each heat exchanger covered here:

(a) the manufacturer's name

(b) the manufacturer's as-built design heat exchanger specification sheet(s)

(c) the manufacturer's as-built design drawings

(d) the manufacturer's acceptance test report, if available

(e) preservice test results, if available

(f) the date the equipment was initially placed in service

11.2 Plans and Procedures

A record shall be maintained of plans and procedures for tests, monitoring, and inspections that shall include the following:

(a) identification of the heat exchangers selected

(b) identification of the method selected for each heat exchanger and a justification for each method selected[3]

(c) identification of the interval selected for each heat exchanger and a justification for each interval selected

11.3 Record of Results

A record shall be maintained of the results for each test, monitoring, or inspection performed to allow for proper evaluation and trending of results. This record shall be maintained for the life of the plant or for the life of the component (whichever is less). This record shall include the following:

(a) identification of the heat exchanger

(b) date of the test, monitoring, or inspection

(c) reason for the test, monitoring, or inspection (e.g., periodic test, periodic maintenance, postmaintenance test)

(d) a complete set of test data, monitoring data, and inspection observations for the "as-found" conditions before any corrective actions (per the requirements of section 5)

(e) a complete set of test data, monitoring data, and inspection observations for the "as-left" conditions following any corrective actions (subject to the exceptions as noted in sections 5 and 10)

(f) identification of calibrated instruments used

(g) a complete record of the test result uncertainty analysis

[3] For methods where inclusion and exclusion criteria are met and the method is not selected (i.e., the uncertainty of the method turns out to be greater than the available margin), a written justification for nonselection is required.

(h) identification of the acceptance criteria used

(i) comparison of the results to the acceptance criteria

11.4 Record of Corrective Action

Records shall be maintained of corrective action, which shall include the following:

(a) a summary of corrective actions taken, including dates

(b) subsequent testing, monitoring, or inspections performed

Part 21, Nonmandatory Appendix A Diagnostics

This Nonmandatory Appendix provides general guidelines to assist in identifying potential causes of abnormal or unexpected performance, as may be indicated by the testing or monitoring methods carried out in accordance with the provisions of Part 21.

Three types of potential inadequacies may be indicated as follows:

(a) heat duty deficiency
(b) excessive pressure loss
(c) mechanical dysfunction

A-1 HEAT DUTY DEFICIENCY

Thermal performance degradation of the heat exchanger below its design point may be due to actual deterioration in the heat exchanger's heat duty due to cooling fluid side fouling, process fluid side fouling, and/or mechanical dysfunction. Degradation may also be indicated due to errors caused by improper application of the methods outlined in Part 21 (e.g., testing errors and/or computational errors).

A-1.1 Cooling Fluid Side Fouling

The most common reason for actual decline in heat exchanger performance is fouling beyond the design point for the heat-transfer surfaces. In most cases, the fouling occurs on the cooling fluid side of the heat exchanger.

A-1.2 Process Fluid Side Fouling

If cleaning of the cooling fluid side does not restore performance, then the possibility of fouling on the process fluid side of the heat exchanger should be investigated. This is best achieved by performing a heat-transfer test following a thorough cleaning on the cooling fluid side. If the performance is still short of design by more than the design fouling resistance, then process fluid side fouling could be occurring.

A-1.3 Mechanical Dysfunction

If thermal performance degradation is not attributable to fouling, then the possibility of mechanical dysfunction should be investigated (see section A-3).

A-1.4 Testing Errors

Potential error or oversight in testing should be carefully scrutinized whenever discrepancies between the test results and expected heat exchanger performance occur. Some typical examples of causes of errors in testing of heat exchangers are presented below.

(a) The instrumentation is imprecise, faulty, or inadequate. The demand on the level of required instrument accuracy depends on the temperature approach in the heat exchanger under the test conditions. The test engineer should establish the instrument accuracy level requirements and establish that the selected or available instrumentation is adequate. The measurement of vital data (i.e., flow rates and terminal temperatures) should have, insofar as possible, redundancy to provide a means of double-checking key data. Additional measurements (i.e., of intermediate fluid temperature between two shell or tube passes) can also provide useful information to identify performance deficiencies. For pressure measurements, deposits on or around the sensing element or pressure tap may result in significant error.

(b) The heat load for the test is inadequate. This is closely tied to errors, sensitivities, and uncertainties, as discussed in Part 21. Heat loads that might not otherwise be available during testing can be provided by scheduling testing (when possible) during plant cool-down for decay heat coolers, during heatup and recirculation of water in the borated (refueling) water storage tank for containment spray heat exchangers, by using reactor building temperature during startup for containment coolers, using spent fuel pool heat, using supplemental heaters, as well as other methods. When using supplemental heaters, it is necessary to ensure that adequate mixing of the heated air is occurring.

(c) The flow rates selected for testing result in severe temperature cross (a condition where the cold fluid outlet temperature exceeds the hot fluid outlet temperature) such that the heat exchanger performance is insensitive to large oscillations in flows.

(d) Testing is performed without complete vent-off of the noncondensibles. Trapped air (i.e., an air pocket) may render a portion of the tube bundle ineffective during the test.

(e) The heat exchanger is not allowed to reach steady-state conditions before test data collection is begun (for those methods where steady state is part of the inclusion criteria).

A-1.5 Computational Errors

Computational errors arise from improper mathematical analysis of the test data. Some examples of incorrect analysis are presented below.

(a) The tube- or shell-side flow rate during the testing condition is sufficiently low so as to produce laminar conditions in all or part of the tube bundle while the mathematical analysis uses turbulent flow correlations.

(b) Fouling on the tube surfaces has occurred unevenly in different tube passes while the mathematical analysis assumes uniform fouling deposition.

(c) Extensive plugging of tubes in one or two passes has caused gross inequalities in the number of tubes in the different passes while the mathematical analysis considers equal number of tubes in each tube pass.

(d) The header design of the heat exchanger produces appreciable flow maldistribution among the tubes while the analysis assumes uniformly distributed flow.

(e) The baffle configuration is not appropriately modeled.

A-2 EXCESSIVE PRESSURE LOSS

Measurement of pressure loss is an important way to obtain heat exchanger performance characteristics that are not so easily derived from thermal data alone. Pressure loss is discussed below in terms of tube side, shell side, and in plate heat exchangers.

A-2.1 Tube-Side Pressure Loss

Excessive tube-side pressure loss is almost always an indicator of a large accumulation of foreign matter (macrofouling) in the tubes, or on the tube sheet, leading to flow blockage and roughening of the tube inner surface. Moderate pressure loss may be the result of biological fouling (or other microfouling) of the tube inner surface (see Nonmandatory Appendix B of this Part, section B-11).

A-2.2 Shell-Side Pressure Loss

Excessive shell-side pressure loss generally originates from flow blockage, although the blockage mechanism may be more complex. Clearances between the baffles and the shell ID, and between the tubes and baffle holes, contribute to the reduction of the overall shell-side pressure loss by diverting some of the flow into the leakage and bypass streams. Deposition of corrosion products in these narrow passages may alter the flow field in the heat exchanger, resulting in an increased portion of the shell-side flow in crossflow, causing an increase in pressure loss as well as an increase in heat transfer.

A-2.3 Plate Heat Exchanger Pressure Loss

Excessive pressure loss in plate heat exchangers generally originates from flow blockage, although it can also originate from fouling of the plate surfaces (see Nonmandatory Appendix B of this Part, section B-10).

A-3 MECHANICAL DYSFUNCTION

If flushing or cleaning does not restore performance, then the possibility that mechanical dysfunction may be causing the performance degradation should be investigated. In most cases, mechanical dysfunction is intrinsic to the design and/or manufacture of the heat exchanger. In certain limited instances it is possible to modify the heat exchanger to eliminate or minimize the effects of such dysfunctions. These dysfunctions may include, but are not limited to, those described below.

A-3.1 Tube Vibration

Over a period of time, steel baffles in certain heat exchangers may corrode, resulting in enlargement of baffle holes. An enlarged baffle hole enables the tube to vibrate with a larger amplitude. The effect of this vibration on the heat-transfer rate is small when in the turbulent regime. However, under laminar conditions, tube mechanical vibration may cause a change in flow regimes, and thus alter the shell-side film coefficient.

Another reason for tube vibration is inadequate baffle spacing for the shell-side flows. This problem usually reveals itself during initial operation of the heat exchanger. Additional staking (the process of inserting a "stake" between adjacent tube rows to limit tube displacement under dynamic conditions) may be required to prevent collisions between adjacent tubes by limiting movement at the center of the unsupported tube span.

In a properly designed heat exchanger, tube vibration usually does not occur unless the shell-side flow is greater than twice the design flow. If a heat exchanger has tube vibration with laminar flow, then something is seriously wrong with the heat exchanger.

A-3.2 Interfluid Leakage

Massive tube leaks may cause errors in pressure measurements, affecting the accuracy of the methods that rely on pressure, and the conclusions drawn from them. For example, a tube leak could cause the corrected pressure loss to be low (normally a good indication) when in fact the performance of the heat exchanger is degraded (due to the tube leak).

Another path for interfluid leakage is at the tube-to-tube sheet interface. Often a very small leakage path in this area will increase in size due to the high ΔP between the tube side and the shell side. This will result in a "worm hole," which will allow leakage between the tube and shell sides.

Because plate-type heat exchangers are especially sensitive to flow and pressure loss, leakage between plates can significantly affect the accuracy of results.

A-3.3 Air In-Leakage

Inlet air in-leakage on ducted air coolers could cause erroneous test results. If the air in-leakage is downstream of where the air flow is being measured, the actual air flow across the coil will not be accurately measured. Likewise, if air temperature is being measured upstream of where the air in-leakage is, the inlet air temperature may not be accurately measured, especially if the air in-leakage temperature is significantly different than the ducted air temperature. If test results for the ducted air cooler appear erroneous, inlet air in-leakage should be considered, located, and quantified.

A-3.4 Internal Bypass Flow

Although less common than fouling as a cause for performance degradation, internal bypass flow may occur in both tube and shell sides, and its effect on reducing the heat duty may be quite considerable [see references in Part 21, subparas. 3.2(a) and (b)]. Furthermore, the corrected pressure loss may indicate low (normally a good indication), when, in fact, the condition of the heat exchanger is significantly degraded due to the bypass flow. Internal bypass flow often results in temperature stratification of the outlet fluids due to inadequate mixing and/or nonuniform heating of the fluid. This may significantly affect the accuracy of the measured outlet fluid temperatures (refer to Nonmandatory Appendix B of this Part, section B-3).

Changes in internal bypass flow may occur in heat exchangers due to the following:

(a) internal deformations caused by shop or system pressure testing of the equipment; typical of such a situation is the bowing of the unstayed (U-tube) tube sheet when the heat exchanger is hydrotested.

(b) internal deformations due to improper construction, fluid impingement forces, and/or excessive thermal strain. Typical of such a situation is the failure (either damaged or missing) of a pass partition plate gasket due to excessive flow excursions, which results in significant shell-side flow bypassing the tube bundle. Another example is deformation of pass partition plates in the channels of certain types of heat exchangers (e.g., TEMA types A and C) due to high differential pressures caused by tube blockage, resulting in tube-side bypass flow.

(c) misinstallation or wear of longitudinal baffle seal strips (used in certain removable bundle TEMA type F or G shells).

Part 21, Nonmandatory Appendix B
Precautions

Some precautionary measures to avoid misinterpretation of test data and to prevent damage to the equipment during testing are presented below.

B-1 EXCESSIVE FLOW

Testing the heat exchanger at a shell-side flow rate that exceeds the design flow rate should not be done unless the tubes are determined to be safe from flow-induced vibration (refer to Part 11 for additional discussion).

Testing the heat exchanger at tube-side flow rates that exceed the design point may not present a serious problem as long as the testing is of limited duration.

Excessive flow rates may occur when performing flow balance testing of the system.

When heat exchangers are designed for series or parallel operation or when pumps operate in parallel, there exists the potential for operating a heat exchanger in excess of its allowable flow. The flow rates may increase to a point that will cause malfunction or damage to the operating unit. Listed below are three situations that can result in an overload or an abnormal operating mode as a result of flow conditions.

(a) removing a heat exchanger from service that is designed for parallel flow operation without throttling flow to the heat exchanger remaining in service

(b) removing a heat exchanger from service that is designed for series flow operation without adjusting the flow rates to the heat exchanger remaining in service

(c) operating a heat exchanger with increased pumping capacity; for example, with three half-capacity cooling water pumps operating in parallel

If the design limits are exceeded, accelerated erosion and failure may occur. There are no definitive guidelines presently available that can adequately determine the relationship of erosion to length of time at overload or abnormal operating conditions.

B-2 CROSSING FLOW REGIMES

If laminar flow is assumed, care should be taken to ensure that vibration around the heat exchanger does not cause the laminar flow to transition to turbulent flow.

If turbulent flow is assumed, then the only method that will allow for the extrapolation of test data from laminar to turbulent flow is the heat-transfer method.

It should be noted that reducing flow rates below the design flow rates (to increase temperature differences and, thus, to increase test accuracy) will require extrapolation back to the original design conditions. The reduced flow rates may also prevent the heat exchanger from achieving steady-state conditions.

When using one of the heat-transfer coefficient test methods, the heat exchanger should be tested at a sufficient number of shell-side flow rates to allow multiple shell-side film coefficients to be back-calculated from the preservice test data. This will allow extrapolation of the shell-side film coefficient at any future inservice test shell-side flow rate.

B-3 TEMPERATURE STRATIFICATION

Temperature stratification may occur whenever thermal streams within a fluid are not adequately mixed. Since many of the test thermowells provided by system designers are located directly on the outlets of the heat exchangers, where thermal streams are likely to exist and where adequate mixing is not likely to occur, most temperature stratification problems occur in measuring *outlet* fluid temperatures. This problem can be minimized by intentionally mixing the thermal streams, and then taking the temperature measurement *downstream* from where the mixing occurs. Mixing can be achieved by allowing the outlet fluid to pass through at least two pipe bends or through a discharge valve prior to measurement. If this or other measures are not possible, then provisions should be made to install at least two temperature sensors, 90 deg apart, and then average the readings.

When *laminar* flow is assumed, there is the increased possibility of having temperature stratification.

B-4 OVERCOOLING

Maintaining turbulent flow for the duration of the test (to keep the correlations valid) could result in overcooling systems served by the heat exchanger. This is especially true if the heat exchanger is operating at a reduced heat load for testing and/or if the test occurs during a period of cold cooling water temperatures.

B-5 FLASHING

Flashing of the cooling or process fluid may occur if there is a loss of static pressure in the fluid system.

This situation should be evaluated not only for the test condition but also for the design accident condition to ensure that the flashing will not restrict the required flow of the fluid.

Flashing will result in misleading fluid temperatures, since the latent heat going into flashing will lower the fluid temperature toward saturation.

Flashing will also invalidate many of the methods described in Part 21, since the correlations used assume that flashing is not occurring.

B-6 EFFECTIVE SURFACE AREA

When evaluating heat exchanger performance using the heat-transfer method, any deliberate tube plugging (including those plugged during initial service) should be considered by removing the effective surface area of the plugged tubes from the total effective surface area. The reduction in the number of tubes available for flow will increase velocity through the remaining tubes and, hence, increase the inside film coefficient, h_i. While these two effects will tend to offset each other, they must still be taken into account to ensure an accurate evaluation of the overall heat-transfer coefficient and the total heat duty.

If "enhanced tubes" (i.e., tubes with internal or external fins) are used in the heat exchanger, then the effective surface area due to these enhancements must be properly accounted for (i.e., accounting for the area on *both* sides of a finned surface).

When evaluating heat exchanger performance using the pressure loss method, tube plugging will result in a higher differential pressure across the heat exchanger for a given flow rate. Thus, tube plugging must be accounted for here as well.

B-7 WATER HAMMER

In establishing system alignment and conditions for testing, precautions should be taken to prevent the occurrence of water hammers.

B-8 MISCELLANEOUS CONSIDERATIONS

While the criteria for selection of methods (as presented in Part 21) should, in general, be followed, there may be special circumstances that call for a deviation from these criteria. Such circumstances may include, but are not limited to, the following:

(a) if the selected method would result in a greater safety risk than an alternate method

(b) if the selected method would result in a greater radiation exposure than an alternate method

(c) if the selected method would result in unacceptable safety system unavailability

Where radiation exposure is a concern, consideration should be given to performing one overall test of a pair or group of heat exchangers together, as one larger heat exchanger, to minimize exposure to test personnel.

B-9 FLOW INSTABILITY

Flow instability (oscillations) must be avoided.

B-10 PLATE HEAT EXCHANGERS

While Part 21 primarily addresses shell and tube heat exchangers (as shell and tube heat exchangers currently dominate most safety-related applications), Part 21 has been written to be applicable to "plate and frame" or "plate" heat exchangers as well. However, due to the significant differences between these two types of heat exchangers, caution should be exercised when applying Part 21 to plate heat exchangers. In many instances, the manufacturer will need to be solicited for specific design parameters and constants (which are often considered proprietary) before applying Part 21 to plate heat exchangers.

Some additional precautions are described below.

B-10.1 Torque Requirements

If plate heat exchangers are being used, it is critical that the manufacturer's recommendation be followed for tightening torque when assembling the plates. Failure to do so may result in leaking gaskets and decreased performance.

B-10.2 Flow Stability

Plate heat exchanger pressure losses are very sensitive to changes in flow. Thus, flow stability becomes even more important for plate heat exchangers when using the pressure-loss monitoring method.

B-11 FOULING CHARACTERISTICS

The type of fouling present in the heat exchanger can significantly affect the test and/or monitoring results. If the fouling layer creates a *smooth* constriction (as is typical of scaling deposits), then extremely low changes in pressure loss are associated with fouling levels that can cause significant degraded heat transfer. If, however, the fouling layer creates a *rough* constriction (as is typical of most biofilms) or results in tube plugging at the inlet tube sheet, then the pressure loss can be significantly higher than that calculated due to smooth constriction and may serve as a very good indicator of fouling due to blockage.

B-12 COMPONENT DESIGN FUNCTION

Although Part 21 is written to ensure that heat exchangers meet their "safety function," it is also important to compare results to the heat exchanger "design function." This is important because of the "margin" that may exist between the "safety" performance point and the "design" performance point. For example, cleaning a heat exchanger that has margin to the point of meeting its safety performance point may still leave some residual fouling on the tubes that could later result in tube pitting. Thus, comparing results to the safety function of the heat exchanger is important to ensure operational readiness, but this should not exclude comparing results to the design function of the heat exchanger to ensure reliability.

B-13 THERMAL DELAYS

Errors, in addition to the bias and precision errors discussed in section 8 of Part 21, may be introduced into testing by the following thermal delays:

(a) Temperature Measurement Transient Response. The difference between the actual fluid temperature and the indicated fluid temperature due to the thermal inertia of the measuring device (e.g., thermal delays due to the thermal resistance of piping, if using surface-mounted temperature sensors, or due to the thermal resistance of thermowells and air spaces, if using thermowells).

(b) Temperature Measurement External Transport Timeshift. The difference between actual fluid temperature and indicated fluid temperature due to the fluid transport delay time between the heat exchanger and the location of the temperature-measuring device, external to the heat exchanger.

(c) Temperature Measurement Internal Transport Timeshift. The change in fluid outlet temperature in response to a change in fluid inlet temperature, prior to establishing a new steady state and due to the transport delay time of the fluid passing through the heat exchanger.

These thermal delays should be properly accounted for to minimize additional errors. By properly applying the testing and monitoring conditions as outlined in Part 21, section 7 (e.g., achieving steady-state test conditions), these additional errors can be minimized.

B-14 MATERIAL PROPERTIES

Where heat exchanger tube (or plate) material has been changed from a copper alloy to a stainless steel alloy, biological fouling may be experienced even though it may not have been experienced with the copper alloy. This is because copper alloys create a toxic film that tends to retard biological growth.

Part 21, Nonmandatory Appendix C Examples

This Nonmandatory Appendix provides examples to demonstrate simplified application of the methods described in Part 21. Paragraph 3.2 provides additional references that may be used if more complex application of the methods is required.

C-1 FUNCTIONAL TEST METHOD

The methodology used in the following example involves determining the temperature of interest (in this case, containment spray pump bearing temperatures), and then comparing it with the acceptance criteria (in this case, the pump manufacturer's maximum allowed temperature). The test is performed with the cooling system (in this case, component cooling water, or CCW) placed in a simulated design accident condition.

As demonstrated by the following example, the functional test method is ideally suited for heat exchangers on a closed cooling loop system, as the temperature of the closed cooling loop can be more easily manipulated than that of an open cooling loop.

C-1.1 Establish Cooling Water Maximum Design Conditions

The CCW system is allowed to climb to and stabilize at its 130°F design temperature by reducing the service water flow through the CCW heat exchanger.

C-1.2 Establish Flow

The CCW flow through the bearing coolers is brought to the design point via system alignment, but the flow need not be measured.

C-1.3 Establish Temperature of Interest Design Conditions

The containment spray pump is then operated and the two pump-bearing temperatures reach steady-state values of 143°F and 145°F.

C-1.4 Compare the Temperature of Interest to the Acceptance Criteria

If both of these temperatures are below the pump manufacturer's maximum allowed value of 158°F, then the bearing coolers are operable.

C-2 HEAT TRANSFER COEFFICIENT TEST METHOD (WITHOUT PHASE CHANGE)

The heat transfer coefficient test method (without phase change) is used to determine the heat transfer capability of the heat exchanger. The heat transfer capability may be calculated in terms of either of the two following quantities, Q_p and r_t:

(a) Q_p (the projected heat duty at design accident conditions). Q_d (the required heat duty at design accident conditions) would represent the "system operability limit" and would be used to develop the "required action limit" for the acceptance criteria (see section 9).

(b) r_t (the total fouling resistance at the test conditions). r_d (the total fouling resistance specified at design accident conditions) would represent the "system operability limit" and would be used to develop the "required action limit" for the acceptance criteria (see section 9).

In terms of the equations that follow,

$$r_t = r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})$$

and

$$r_d = r_{o,d}(1/E_f) + r_{i,d}(A_{o,d}/A_{i,d})$$

where (dropping the subscripts "t" for "test conditions" and "d" for "design accident conditions")

A_i = inside effective surface area, ft^2, based on inside surface area, including any fin area

A_o = total effective surface area, ft^2, based on outside surface area, including any fin area

A_o/A_i = ratio of total-to-inside effective surface area (dimensionless)

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

r = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area

r_i = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area

r_o = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area

For the heat transfer coefficient test method (without phase change), first, the design film coefficients are calculated using the mean temperature difference (MTD) method and back-calculation. Then, the performance under test conditions is evaluated using either the MTD method or the NTU method. Finally, the projected heat transfer rate (Q_p) of a heat exchanger under design accident (emergency) conditions is determined, given the current fouling level measured under test conditions.

The methodology used in the example below can be applied to any heat exchanger, with the exception of coil-tube heat exchangers.

The example is for a decay heat cooler that is a shell-and-tube heat exchanger with the process fluid on the shell side and the cooling fluid on the tube side. The heat exchanger is designed as a counterflow type with one shell pass and two tube passes.

This is a relatively simple example that assumes that no tubes are plugged and there is an equal number of tubes in each tube pass. The relationship for the log mean temperature difference correction factor can be easily solved and is well documented in the literature.

The data set given in para. C-2.1 is taken from the design accident conditions and is used to back-calculate the outside film coefficient, based on outside surface area, at design accident conditions. The data set given in para. C-2.2 is taken from the test point and is used to project the heat duty at design accident conditions by using the ratio method to calculate the outside film coefficient, based on outside surface area, at the test conditions and solving for the total fouling resistance at the test conditions.

In the example below, the cooling fluid flow rate is the same at the test and design accident conditions; however, the cooling and process fluid inlet temperatures and the process fluid flow rate at the test conditions are less than their corresponding values at the design accident conditions.

C-2.1 Evaluation at Design Accident Conditions (MTD Method)

C-2.1.1 Calculate *LMTD*$_d$. For parallel flow

$$LMTD_d = \frac{(T_{1,d} - t_{1,d}) - (T_{2,d} - t_{2,d})}{\ln[(T_{1,d} - t_{1,d})/(T_{2,d} - t_{2,d})]}$$

For true counterflow

$$LMTD_d = \frac{(T_{1,d} - t_{2,d}) - (T_{2,d} - t_{1,d})}{\ln[(T_{1,d} - t_{2,d})/(T_{2,d} - t_{1,d})]}$$

where

$LMTD_d$ = log mean temperature difference, °F, at design accident conditions
$T_{1,d}$ = process fluid inlet temperature, °F, at design accident conditions
$t_{1,d}$ = cooling fluid inlet temperature, °F, at design accident conditions
$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions
$t_{2,d}$ = cooling fluid outlet temperature, °F, at design accident conditions

C-2.1.1.1 Data Set (for a Counterflow Heat Exchanger)

$LMTD_d$ = 43.65
$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

C-2.1.2 Calculate *MTD*$_d$

$$MTD_d = (LMTD_d)(F_d)$$

where

F_d = *LMTD* correction factor (dimensionless), to adjust for deviations from true counterflow, at design accident conditions (equals 1 for true counterflow and parallel flow)
$LMTD_d$ = log mean temperature difference, °F, at design accident conditions
MTD_d = mean temperature difference, °F, at design accident conditions

F_d is a function of R_d and P_d and can be obtained from Figs. B-1 through B-9 of the reference given in para. 3.1(b) or Figs. T-3.2A through T-3.2M of the reference in subpara. 3.1(a).

$$R_d = (T_{1,d} - T_{2,d})/(t_{2,d} - t_{1,d})$$
$$P_d = (t_{2,d} - t_{1,d})/(T_{1,d} - t_{1,d})$$

where

P_d = temperature effectiveness (dimensionless) at design accident conditions
R_d = capacity rate ratio (dimensionless) at design accident conditions
$T_{1,d}$ = process fluid inlet temperature, °F, at design accident conditions
$t_{1,d}$ = cooling fluid inlet temperature, °F, at design accident conditions
$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions
$t_{2,d}$ = cooling fluid outlet temperature, °F, at design accident conditions

NOTE: For F correction factor curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1 and t_2 shall be for the tube side fluid.

C-2.1.2.1 Data Set (for a Counterflow Heat Exchanger) (15)

F_d = 0.9588
P_d = $(t_{2,d} - t_{1,d})/(T_{1,d} - t_{1,d})$
= (97.0 − 75)/(140.0 − 75)
= 0.3385
R_d = $(T_{1,d} - T_{2,d})/(t_{2,d} - t_{1,d})$
= (140.0 − 119.3)/(97.0 − 75.0)
= 0.9409
$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-1 of the reference in subpara. 3.1(b)

(b) by calculating the number from the following equation (the subscript "*d*" has been dropped for simplicity):

For $R \neq 1$

$$F = [(R^2 + 1)^{1/2}/(R - 1)]\Bigg[\ln[(1 - P)/(1 - PR)]/ \ln\Bigg(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/ \{2 - P[R + 1 + (R^2 + 1)^{1/2}]\}\Bigg)\Bigg]$$

For $R = 1$

$$F = [P/(1 - P)]\Big(2^{1/2}/\ln\{[2 - P(2 - 2^{1/2})]/[2 - P(2 + 2^{1/2})]\}\Big)$$

Additional equations are available for other flow arrangements, and can be found in the references in subparas. 3.2(h) through (l).

$$LMTD_d = 43.65$$

$$MTD_d = 41.85$$

C-2.1.3 Calculate U_d

$$U_d = Q_d/(A_{o,d})(MTD_d)$$

where

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

MTD_d = mean temperature difference, °F, at design accident conditions

Q_d = heat duty, Btu/hr, based on outside surface area, at design accident conditions, from design specification sheet

U_d = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions[1]

CAUTION: Plugged tubes, if not equally plugged in each tube pass, will result in an unequal number of tubes in passes, and thus violate the assumptions made in the *LMTD* correction factor charts. If this is the case, then computerized methods may need to be employed to accurately solve the problem. For the sake of this example, we are assuming no plugged tubes and equal tube passes.

NOTE: Refer to Nonmandatory Appendix B of this Part, section B-6 for precautions related to effective surface areas.

[1] U_d may also be obtained from technical specifications and design specification sheets.

C-2.1.3.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,d}$ = 5,080
MTD_d = 41.85
Q_d = 65,870,000
U_d = 309.8

C-2.1.4 Calculate r_w (for Back-Calculating $h_{o,d}$). For bare tubes

$$r_w = (d_o/24k)\ln[d_o/(d_o - 2t)]$$

For integral circumferentially finned tubes

$$r_w = \frac{t[d_o + 2nz(d_o + z)]}{12k(d_o - t)}$$

For extended finned tubes

$$r_w = \frac{A_{o,d}\, d_o \ln[d_o/(d_o - 2t)]}{24k(A_{o,\mathrm{tube}})}$$

where

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

$A_{o,\mathrm{tube}}$ = total bare tube surface area, ft^2, based on outside surface area, at design accident conditions

d_o = outside diameter of bare tube or root diameter of fin, in.

k = thermal conductivity of tube wall, Btu/hr-ft-°F, from the reference in subpara. 3.2(g)

n = number of fins per in.

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

t = tube wall thickness, in.

z = fin height, in., from design specification sheet or drawings

C-2.1.4.1 Data Set (for a Counterflow Heat Exchanger)

d_o = 0.75
k = 8.754
n = n/a (bare tubes)
r_w = 0.0004999
t = 0.049
z = n/a (bare tubes)

C-2.1.5 Calculate Re_d (for Back-Calculating $h_{o,d}$)

$$\mathrm{Re}_d = (124 p_d V_d d_i)/\mu_d$$

where

d_i = inside diameter of tube, in.

Re_d = Reynolds number (dimensionless) of the tube side fluid at design accident conditions

V_d = tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)

ρ_d = bulk density, lbm/ft^3, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)

C-2.1.5.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652

Re_d = 49,400 (definitely turbulent flow)

V_d = 7.83

μ_d = 0.7966

ρ_d = 62.16

C-2.1.6 Calculate Pr_d (for Back-Calculating $h_{o,d}$)

$$\mathrm{Pr}_d = (2.42 Cp_d \mu_d)/k_d$$

where

Cp_d = specific heat, Btu/lbm-°F, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(e)

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(e)

Pr_d = Prandtl number (dimensionless) of the tube side fluid at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)

C-2.1.6.1 Data Set (for a Counterflow Heat Exchanger)

Cp_d = 0.9982

k_d = 0.3556

Pr_d = 5.411

μ_d = 0.7966

C-2.1.7 Calculate $h_{i,d}$ (for Back-Calculating $h_{o,d}$). For turbulent flow, $\mathrm{Re}_d > 10{,}000$

$$h_{i,d} = 0.023(12k_d/d_i)(\mathrm{Re}_d)^{0.8}(\mathrm{Pr}_d)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

For laminar flow, $\mathrm{Re}_d < 2{,}100$

$$h_{i,d} = 1.86(12k_d/d_i)(\mathrm{Re}_d)^{1/3}(\mathrm{Pr}_d)^{1/3}(d_i/L)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

where

d_i = inside diameter of tube, in.

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(e)

L = total length of tube, in., carrying flow, from design specification sheet or drawings

Pr_d = Prandtl number (dimensionless) of the tube side fluid at design accident conditions

Re_d = Reynolds number (dimensionless) of the tube side fluid at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in subpara. 3.2(f)

$\mu_{w,d}$ = absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature at design accident contitions, from the reference in subpara. 3.2(f)

C-2.1.7.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652

$h_{i,d}$ = 1503

k_d = 0.3556

L = n/a (turbulent flow)

Pr_d = 5.411

Re_d = 49,400

μ_d = 0.7966

$\mu_{w,d}$ = 0.7966 (use same value as μ_d for this temperature range)

C-2.1.8 Calculate E_f (for Back-Calculating $h_{o,d}$)

$$E_f = 1 - [A_{\mathrm{fin},d}/A_{o,d}][1 - \eta]$$

where

$A_{\mathrm{fin},d}$ = total fin surface area, ft^2, at design accident conditions

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

E_f = weighted average of efficiency of outside surface

η = fin efficiency

For efficiencies of fins around a single tube, the fin efficiency, η, may be calculated using Fig. C-4.1 of the reference in subpara. 3.2(d). If a fin is shared by more than one tube, the area associated with one tube may be calculated by dividing the fin sheet area by the number of tubes penetrating this fin.

$$d_{\mathrm{fin}} = [(4A_{\mathrm{sheet}}/n\pi) + d_o^2]^{1/2}$$

where

A_{sheet} = area of one side of multitube fin, in.^{2}

d_{fin} = equivalent diameter of a single tube fin, in.

d_o = outside diameter of bare tube, in.

n = number of tubes sharing single fin

This d_{fin}, along with other fin parameters, can be used to calculate fin efficiency, η.

$$(1/h_{\text{fin},d}) = (1/h_{o,d}) + r_{o,d}$$

where

$h_{\text{fin},d}$ = film coefficient of fin, Btu/hr-ft^2-°F, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{o,d}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, assumed for design accident conditions, from design specification sheet

Since $h_{o,d}$ depends on E_f, and E_f depends on $h_{o,d}$, the solution is iterative.

C-2.1.9 Using the Values Calculated Above, Back-Calculate $h_{o,d}$

$$U_d = 1/[r_{o,d}(1/E_f) + r_{i,d}(A_{o,d}/A_{i,d}) + (1/h_{o,d})(1/E_f) + r_w + (1/h_{i,d})(A_{o,d}/A_{i,d})]$$

which becomes

$$h_{o,d} = 1/E_f[(1/U_d) - (r_{o,d}/E_f) - r_{i,d}(A_{o,d}/A_{i,d}) - r_w - (1/h_{i,d})(A_{o,d}/A_{i,d})]$$

where

$A_{i,d}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, at design accident conditions

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

$A_{o,d}/A_{i,d}$ = ratio of total to inside effective surface area (dimensionless) at design accident conditions

E_i = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{i,d}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, assumed for design accident conditions, from design specification sheet

$r_{o,d}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, assumed for design accident conditions, from design specification sheet

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_d = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

If either $r_{i,d}$ or $r_{o,d}$ is not given, assume it is equal to zero.

CAUTION: The $h_{o,d}$ calculated by this method will be valid for the test condition only if the shell side test flow is maintained in the same flow regime as the shell side design flow, and only if phase conditions are the same for the test and design conditions. If these conditions cannot be met, then the direct calculation method (below) or a computerized method must be used.

C-2.1.9.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,d}/A_{i,d}$ = 1.15
E_f = 1.0
$h_{i,d}$ = 1,503
$h_{o,d}$ = 2,581
$r_{i,d}$ = 0.0005
$r_{o,d}$ = 0.001
r_w = 0.0004999
U_d = 309.8

C-2.1.10 Calculate $h_{o,d}$ (Direct Calculation Method).

Empirical relationships for h_o may be found in the literature that allows for direct calculation at different flow rates and for different configurations [for these relationships and direct calculation methods, refer to subpara. 3.2(m) and references therein].

C-2.1.10.1 Data Set (for a Counterflow Heat Exchanger)

$h_{o,d}$ = n/a (using back-calculation method)

C-2.2 Evaluation at Test Conditions

C-2.2.1 Collect the Test Data. Record the following temperature and flow data at steady-state conditions. This set of data will be termed the test point. Only five of the six parameters are required (the sixth being calculated); however, for validity purposes (see para. 8.5 of this Part) it is recommended that all six parameters be recorded.

$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions

$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions

$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions

$W_{p,t}$ = process fluid flow rate, lbm/hr, at test conditions

C-2.2.1.1 Data Set (for a Counterflow Heat Exchanger)

$T_{1,t}$ = 120.0
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7
$W_{c,t}$ = 3,000,000
$W_{p,t}$ = 2,500,000

C-2.2.2 Calculate Q_t (*MTD* Method). For process fluid

$$Q_{p,t} = W_{p,t}[Cp_{p,t}(T_{1,t} - T_{2,t})]$$

For cooling fluid

$$Q_{c,t} = W_{c,t}[Cp_{c,t}(t_{1,t} - t_{2,t})]$$

where

$Cp_{c,t}$ = bulk specific heat, Btu/lbm-°F, of the cooling fluid at test conditions, from the reference in para. 3.2(e)
$Cp_{p,t}$ = bulk specific heat, Btu/lbm-°F, of the process fluid at test conditions, from the reference in para. 3.2(e)
$Q_{c,t}$ = heat duty, Btu/hr, for the cooling fluid at test conditions
$Q_{p,t}$ = heat duty, Btu/hr, for the process fluid at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions
$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions
$W_{p,t}$ = process fluid flow rate, lbm/hr, at test conditions

NOTE: Refer to para. C-11.4 for guidance on which of the above parameters should be measured and which should be calculated.

C-2.2.2.1 Data Set (for a Counterflow Heat Exchanger)

$Cp_{c,t}$ = 0.9988
Q_t = 56,030,000
$t_{1,t}$ = 60.0
$t_{2,t}$ = 78.7
$W_{c,t}$ = 3,000,000 (note that test was done at design flow rate)

C-2.2.3 Calculate $LMTD_t$ (*MTD* Method). For parallel flow

$$LMTD_t = \frac{(T_{1,t} - t_{1,t}) - (T_{2,t} - t_{2,t})}{\ln[(T_{1,t} - t_{1,t})/(T_{2,t} - t_{2,t})]}$$

For true counterflow

$$LMTD_t = \frac{(T_{1,t} - t_{2,t}) - (T_{2,t} - t_{1,t})}{\ln[(T_{1,t} - t_{2,t})/(T_{2,t} - t_{1,t})]}$$

where

$LMTD_t$ = log mean temperature difference, °F, at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-2.2.3.1 Data Set (for a Counterflow Heat Exchanger)

$LMTD_t$ = 39.37
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

C-2.2.4 Calculate MTD_t (*MTD* Method)

$$MTD_t = (LMTD_t)(F_t)$$

where

F_t = *LMTD* correction factor (dimensionless), to adjust for deviations from true counterflow, at test conditions, equals 1 for true counterflow and parallel flow
$LMTD_t$ = log mean temperature difference, °F, at test conditions
MTD_t = mean temperature difference, °F, at test conditions

F_t is a function of R_t and P_t and can be obtained from Figs. B-1 through B-9 of the reference in subpara. 3.1(b) or Figs. T-3.2A through T-3.2M of the reference in subpara. 3.1(a).

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$

$$P_t = (t_{2,t} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = temperature effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

NOTE: For F correction factor curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1 and t_2 shall be for the tube side fluid.

(15) **C-2.2.4.1 Data Set (for a Counterflow Heat Exchanger)**

F_t = 0.953
P_t = (78.7 − 60)/(120 − 60)
= 0.3117
R_t = (120 − 97.5)/(78.7 − 60)
= 1.203
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-1 of the reference in subpara. 3.1(b)

(b) by calculating the number from the following equation (the subscript "t" has been dropped for simplicity)

For $R \neq 1$

$$F = [(R^2 + 1)^{1/2}/(R - 1)]\left[\ln[(1 - P)/(1 - PR)]/\ln\left(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/\{2 - P[R + 1 + (R^2 + 1)^{1/2}]\}\right)\right]$$

For $R = 1$

$$F = [P/(1 - P)]\left(2^{1/2}/\ln\{[2 - P(2 - 2^{1/2})]/[2 - P(2 + 2^{1/2})]\}\right)$$

Additional equations are available for other flow arrangements, and can be found in the references in subparas. 3.2(h) through (l).

$LMTD_t$ = 39.37
MTD_t = 37.52

C-2.2.5 Calculate U_t (*MTD* Method)

$$U_t = (Q_t)/(A_{o,t})(MTD_t)$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions
MTD_t = mean temperature difference, °F, at test conditions
Q_t = heat duty, Btu/hr, at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

CAUTION: Plugged tubes, if not equally plugged in each tube pass, will result in an unequal number of tubes in passes, and thus violate the assumptions made in the *LMTD* correction factor charts. If this is the case, then computerized methods may need to be employed to accurately solve the problem. For the sake of this example, we are assuming no plugged tubes and equal tube passes.

C-2.2.5.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}$ = 5,080 (note, there is no tube plugging accounted for here)
MTD_t = 37.52
Q_t = 56,030,000
U_t = 294.0

C-2.2.6 Calculate U_t (*NTU* Method)

$$U_t = (NTU_t)(W_{c,t})(Cp_{c,t})/A_{o,t}$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions
$Cp_{c,t}$ = bulk specific heat, Btu/lbm-°F, of cooling fluid at test conditions, from the reference in subpara. 3.2(e)
NTU_t = number of transfer units (dimensionless) at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions
$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions

NTU_t is a function of R_t and P_t, and can be obtained from Figs. B-10 through B-12 of the reference in subpara. 3.1(b) or Figs. T-3.3 through T-3.3B of the reference in subpara. 3.1(a).

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$
$$P_t = (t_{2,i} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = thermal effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

NOTE: For NTU curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1, t_2, $W_{c,t}$ *and* Cp_c shall be for the tube side fluid.

(15) **C-2.2.6.1 Data Set (for a Counterflow Heat Exchanger)**

NTU_t = 0.5
P_t = (78.7 − 60)/(120 − 60)
= 0.3117
R_t = (120 − 97.5)/(78.8 − 60)
= 1.203
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-12 of the reference in subpara. 3.1(b)

(b) by calculating the number from the following equations (the subscript "t" has been dropped for simplicity)

For $R = 0$ and $R =$ infinity

$$NTU = \ln[1/(1 - P)]$$

For $R \neq 0$ and $R \neq$ infinity

$$NTU = [1/(R^2 + 1)^{1/2}]\left[\ln\left(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/\{2 - P[R + 1 + (R^2 + 1)^{1/2}]\}\right)\right]$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through (l).

$A_{o,t}$ = 5,080
$Cp_{c,t}$ = 0.9988
U_t = 294.9
$W_{c,t}$ = 3,000,000

C-2.2.7 Calculate Re_t

$$Re_t = (124\rho_t V_t d_i)/\mu_t$$

where

d_i = inside diameter of tube, in.
Re_t = Reynolds number (dimensionless) of the tube side fluid at test conditions
V_t = tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at test conditions
μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in subpara. 3.2(f)
ρ_t = bulk density, lbm/ft^3, of the tube side fluid at test conditions, from the reference in subpara. 3.2(f)

C-2.2.7.1 Data Set (for a Counterflow Heat Exchanger)

d_t = 0.652
Re_t = 39,900
V_t = 7.8
μ_t = 0.9847
ρ_t = 62.31

C-2.2.8 Calculate Pr_t

$$Pr_t = (2.42 Cp_t \mu_t)/k_t$$

where

Cp_t = bulk specific heat, Btu/lbm-°F, of the tube side fluid at test conditions, from the reference in subpara. 3.2(e)
k_t = thermal conductivity, Btu/hr-ft-°F, of the tube side fluid, at test conditions, from the reference in subpara. 3.2(e)
Pr_t = Prandtl number (dimensionless) of the tube side fluid at test conditions
μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in subpara. 3.2(f)

C-2.2.8.1 Data Set (for a Counterflow Heat Exchanger)

Cp_t = 0.9988
k_t = 0.3474
Pr_t = 6.851
μ_t = 0.9847

C-2.2.9 Calculate $h_{i,t}$. For turbulent flow, $Re_t > 10,000$

$$h_{i,t} = 0.023(12k_t/d_i)(Re_t)^{0.8}(Pr_t)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

For laminar flow, $Re_t < 2,100$

$$h_{i,t} = 1.86(12k_t/d_i)(Re_t)^{1/3}(Pr_t)^{1/3}(d_i/L)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

where

d_i = inside diameter of tube, in.
$h_{i,t}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at test conditions
k_t = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid, at test conditions, from the reference in subpara. 3.2(e)
L = total length of tube, in., carrying flow
Pr_t = Prandtl number (dimensionless) of the tube side fluid at test conditions
Re_t = Reynolds number (dimensionless) of the tube side fluid at test conditions

μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in subpara. 3.2(f)

$\mu_{w,t}$ = absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature, at test conditions, from the reference in subpara. 3.2(f)

C-2.2.9.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652
$h_{i,t}$ = 1,339
k_t = 0.3474
L = n/a (turbulent flow)
Pr_t = 6.851
Re_t = 39,900
μ_t = 0.9847
$\mu_{w,t}$ = 0.9847 (use same value as μ_t for this temperature range)

C-2.2.10 Calculate $h_{o,t}$ (Ratio Method)

$$h_{o,t} = h_{o,d}(W_t/W_d)^{0.6}(\mu_t/\mu_d)^{-0.27}(Cp_t/Cp_d)^{1/3}(k_t/k_d)^{2/3}$$

where

Cp_d = bulk specific heat, Btu/lbm-°F, of the shell side fluid at design accident conditions, from the reference in subpara. 3.2(e)

Cp_t = bulk specific heat, Btu/lbm-°F, of the shell side fluid at test conditions, from the reference in subpara. 3.2(e)

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$h_{o,t}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the shell side fluid at design accident conditions, from the reference in subpara. 3.2(e)

k_t = bulk thermal conductivity, Btu/hr-ft-°F, of the shell side fluid at test conditions, from the reference in subpara. 3.2(e)

W_d = flow rate, lbm/hr, of the shell side fluid at design accident conditions

W_t = flow rate, lbm/hr, of the shell side fluid at test conditions

μ_d = bulk absolute viscosity, centipoise, of the shell side fluid at design accident conditions, from the reference in subpara. 3.2(f)

μ_t = bulk absolute viscosity, centipoise, of the shell side fluid at test conditions, from the reference in subpara. 3.2(f)

C-2.2.10.1 Data Set (for a Counterflow Heat Exchanger)

Cp_d = 0.9990
Cp_t = 0.9985
$h_{o,d}$ = 2,581
$h_{o,t}$ = 2,081
k_d = 0.3730
k_t = 0.3653
W_d = 3,200,000
W_t = 2,500,000
μ_d = 0.5050
μ_t = 0.6146

CAUTION: Although the variable subscripts used for calculating the outside film coefficient are the same as those used for calculating the inside film coefficient, the outside film coefficient variables relate to the shell side fluid and the inside film coefficient variables relate to the tube side fluid (as stated in the variable definitions above).

C-2.2.11 Calculate $h_{o,t}$ (Direct Calculation Method). Empirical relationships for h_o may be found in the literature that allows for direct calculation at different flow rates and for different configurations [for these relationships and direct calculation methods, refer to subpara. 3.2(m) and references therein].

C-2.2.11.1 Data Set (for a Counterflow Heat Exchanger)

$h_{o,t}$ = n/a (using back-calculation method)

C-2.2.12 Calculate r_t. Using the values calculated above, solve the following equation for r_t:

$$U_t = \frac{1}{[r_t + (1/h_{o,t})(1/E_i) + r_w + (1/h_{i,t})(A_{o,t}/A_{i,t})]}$$

where

$A_{i,t}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}/A_{i,t}$ = ratio of total to inside effective surface area (dimensionless) at test conditions

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,t}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at test conditions

$h_{o,t}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

$r_{i,t}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, at test conditions[2]

$r_{o,t}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions[2]

r_t = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

= $r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})$

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

C-2.2.12.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}/A_{i,t}$ = 1.150
E_f = 1.0
$h_{i,t}$ = 1,339
$h_{o,t}$ = 2081
r_t = 0.001562
r_w = 0.0004999
U_t = 294.0

C-2.3 Projection at Design Accident Conditions

C-2.3.1 Calculate U_p. Using the values calculated above, solve the following equation for U_p:

$$U_p = \frac{1}{[r_t + (1/h_{o,d})(1/E_f) + r_w + (1/h_{i,d})(A_{o,t}/A_{i,t})]}$$

where

$A_{i,t}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}/A_{i,t}$ = ratio of total to inside effective surface area (dimensionless) at test conditions

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{i,t}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, at test conditions

$r_{o,t}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

r_t = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

= $r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})$

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_p = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, projected at design accident conditions based on fouling at test conditions

C-2.3.1.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}/A_{i,t}$ = 1.150
E_f = 1.0
$h_{i,d}$ = 1,503
$h_{o,d}$ = 2,581
r_t = 0.001562
r_w = 0.0004999
U_p = 311.1

C-2.3.2 Calculate Q_p. Using the values calculated above, solve the following equation for Q_p:

$$Q_p = (U_p)(A_{o,t})(MTD_d)$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

MTD_d = mean temperature difference, °F, at design accident conditions

Q_p = heat duty, Btu/hr, projected at design accident conditions based on fouling at test condition

U_p = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, projected at design accident conditions based on fouling at test condition

C-2.3.2.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}$ = 5,080
MTD_d = 41.85
Q_p = 66,140,000
U_p = 311.1

[2] Assume the design value (or zero) for either $r_{i,t}$ or $r_{o,t}$ (whichever one is not calculated).

C-3 HEAT TRANSFER COEFFICIENT TEST METHOD (WITH CONDENSATION)

When heat transfer occurs from a steam–air mixture (humid air), the sensible heat transfer takes place because of a temperature difference and the mass transfer occurs because of a difference in steam partial pressure across the convection layer. Heat is released during condensation (latent heat). This heat of condensation penetrates across the tube wall to the cooling fluid inside the tubes. The condensation rate is equal to the mass transfer rate.

Since the condensation rate strongly depends on the saturation pressure at the gas–condensate interface (which depends on the gas–condensate interface temperature), the heat transfer coefficient associated with the convection outside the tubes (and any fins) varies over the heat transfer surface. Also, the change in enthalpy of the steam–air mixture cannot be expressed as $mCp\Delta T$, and a closed form solution for F, or effectiveness, cannot be derived. Because of these two reasons, the heat transfer equations must be integrated numerically.

Basically, the procedure is to vary the fouling resistance until the calculated parameters match the measured parameters. The fouling resistance thus obtained is then used to calculate the heat transfer rate under the design accident conditions.

The methodology used in the following example can be applied to any heat exchanger, with the exception of coil-tube heat exchangers.

C-3.1 Collect the Test Data

Paragraph 6.3 describes the data needed for this test. Various combinations of data can be used. In this example, it has been assumed that the following data are available:

(a) process fluid (steam–air mixture) pressure
(b) cooling fluid inlet temperature
(c) cooling fluid outlet temperature
(d) process fluid (steam–air mixture) inlet temperature
(e) process fluid (steam–air mixture) outlet temperature
(f) cooling fluid flow rate
(g) process fluid (steam–air mixture) inlet relative humidity

(15) C-3.2 Write the Finite Difference Equations

Write the finite difference equations of the heat transfer process. Equations (C-1) to (C-24) are shown here as a guide. These equations are for a cross-flow unmixed heat exchanger having only one tube row with fins on the outside. Figure C-1 shows this heat exchanger along with its j^{th} finite element bounded by two parallel planes in the y-z plane. The airflow is along the y direction. The water flow is along the x direction. The flow parameters along the z direction are uniform. The governing equations for more complex geometries having many tube rows and passes can be written in a similar fashion.

Figure C-2 shows a fin, condensate layer, and interface temperatures.

From the law of conservation of mass applied to the fluid outside the tubes in the j^{th} element of the heat exchanger, note the following:

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = W_{\text{cond},j} \tag{C-1}$$

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = M_A N_{A,j}\left(\frac{A}{b}\right) \tag{C-2}$$

$$\phi_{1,j} = \phi_{\text{in}};\ 1 \le j \le N$$

where

A = total outside heat transfer area, ft^2 = $A_{\text{fin}} + A_{t,\text{exp}}$ [see eq. (C-6)]
b = length of heat exchanger along water flow direction, ft
M_A = molecular weight of vapor, lbm/lbm-mole
$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of heat exchanger
$W_{\text{cond},j}$ = mass flow rate of condensate generated per unit length, lbm /hr-ft, along the direction of water flow of j^{th} element of heat exchanger
W_{da} = mass flow rate of dry air per unit length, lbm /hr-ft, along the direction of water flow
$\phi_{1,j}$ = vapor-to-dry air mass ratio upstream of tube row of j^{th} element of heat exchanger
$\phi_{2,j}$ = vapor-to-dry air mass ratio downstream of tube row of j^{th} element of heat exchanger
ϕ_{in} = vapor-to-dry air mass ratio at inlet

From the law of conservation of energy applied to the fluid outside the tubes in the j^{th} elements of the heat exchanger, note the following:

$$W_{da}(e_{1,j} - e_{2,j}) = U_j\left(\frac{A}{b}\right)\left[\frac{1}{2}\left(T_{\infty 1,j} + T_{\infty 2,j}\right) - T_{1,j}\right] + (W_{\text{cond},j})(e_{\text{cond},j}) \tag{C-3}$$

$$e_{1,j} = e_{in}$$

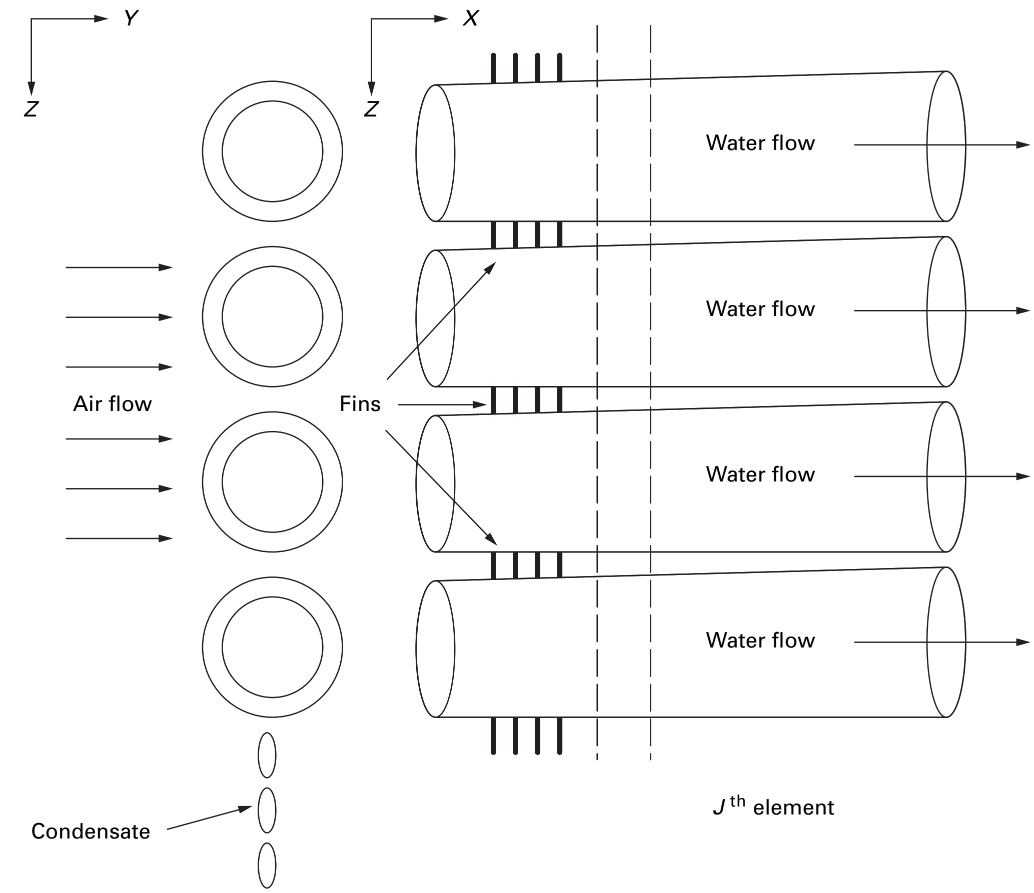
$$T_{\infty 1,j} = T_{\infty,\text{in}} \quad ; \quad 1 \le j \le N$$

$$e = f_1(\phi, T_\infty) \tag{C-4}$$

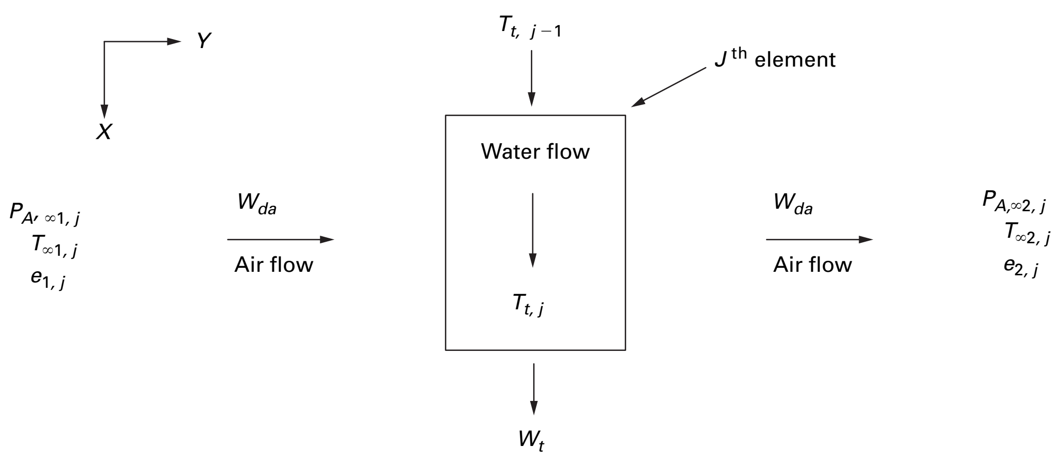
where

A = total outside heat transfer area, ft^2 = $A_{\text{fin}} + A_{t,\text{exp}}$ [see eq. (C-6)]
b = length of heat exchanger along water flow direction, ft
$e_{1,j}$ = enthalpy of air-vapor mixture, Btu/lbm of dry air, upstream of tube row of j^{th} element of the heat exchanger

Fig. C-1 One Tube Row Air-to-Water Cross-Flow Heat Exchanger

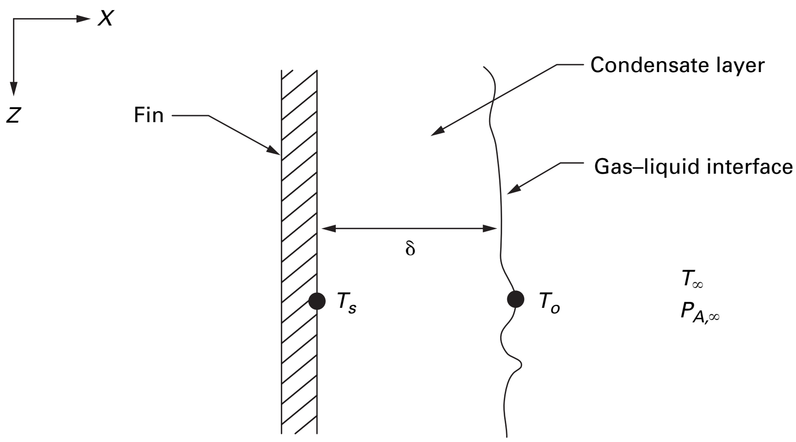


(a) Heat Exchanger and Fins



(b) J^{th} Element

Fig. C-2 Fin, Condensate Layer, and Interfaces



$e_{2,j}$ = enthalpy of air-vapor mixture, Btu/lbm of dry air, downstream of tube row of j^{th} element of the heat exchanger
$e_{cond,j}$ = enthalpy of the condensate, Btu/lbm, of j^{th} element of the heat exchanger
e_{in} = enthalpy of the air-vapor mixture, Btu/lbm *da*, at the inlet
f_1 = functional operator 1
T_∞ = temperature, °F, of air-vapor mixture
$T_{\infty 1,j}$ = temperature, °F, of air-vapor mixture upstream of the tube row of j^{th} element of the heat exchanger
$T_{\infty 2,j}$ = temperature, °F, of air-vapor mixture downstream of the tube row of j^{th} element of the heat exchanger
$T_{\infty,in}$ = temperature, °F, of air-vapor mixture at inlet
$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger
U_i = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
$W_{cond,j}$ = mass flow rate of condensate generated per unit length, lbm/hr-ft, along the direction of water flow of j^{th} element of heat exchanger
W_{da} = mass flow rate of dry air per unit length, lbm/hr-ft, along the direction of water flow
ϕ = vapor-to-dry air mass ratio

From the law of conservation of energy applied to the fluid inside the tubes in the j^{th} element of the heat exchanger, note the following:

$$(WCp)_t(T_{t,j} - T_{t,j-1}) = U_j(\Delta A)\left[\frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) - T_{t,j}\right] \tag{C-5}$$

$$1 \le j \le N$$

$$T_{t,0} = T_{t,in} \quad \text{and} \quad T_{t,out} = T_{t,N}$$

where
A = total outside heat transfer area, ft^2 = A_{fin} + $A_{t,exp}$ [see eq. (C-6)]
ΔA = area, ft^2, of a finite element of the heat exchanger (also total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been subdivided) = A/N
N = number of elements into which the heat exchanger has been subdivided
$T_{\infty 1,j}$ = temperature, °F, of air-vapor mixture upstream of tube row of j^{th} element of the heat exchanger
$T_{\infty 2,j}$ = temperature, °F, of air-vapor mixture downstream of tube row of j^{th} element of the heat exchanger
$T_{t,in}$ = tube side fluid inlet temperature, °F
$T_{t,0}$ = tube side fluid temperature, °F, upstream of the first heat exchanger element
$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger
$T_{t,j\text{-}1}$ = tube side fluid temperature, °F, of $(j - 1)^{th}$ element of the heat exchanger
$T_{t,out}$ = tube side fluid outlet temperature, °F
U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
$(WCp)_t$ = product of the tube side flow rate and specific heat, Btu/hr-°F

The local heat transfer coefficient is a function of local temperature and vapor partial pressure and needs to be calculated simultaneously. To evaluate the local overall heat transfer coefficient, the following equations can be established using the law of conservation of energy, various constitutive relationships, and definitions. The overall heat transfer coefficient can be expressed in terms of individual conductances as follows:

$$\frac{1}{U_j(A_{\text{fin}} + A_{t,\text{exp}})} = \frac{1}{h_{\text{fin},j}(\eta_j A_{\text{fin}} + A_{t,\text{exp}})} + \frac{d_o \ln(d_o/d_i)}{2k_{\text{wall}}A_o} + \frac{1}{A_i}\left(\frac{1}{h_i} + r_{fi}\right) \quad \text{(C-6)}$$

where

A_{fin} = surface area of the fins, ft^2

A_i = inside area of the tubes, ft^2

A_o = outside area of the tubes, ft^2

$A_{t,\text{exp}}$ = outside exposed area of tubes, ft^2; this is the area of the tubes that is in direct contact with the outside fluid

d_j = inside diameter of the tube, ft

d_o = outside diameter of the tube, ft

$h_{\text{fin},j}$ = heat transfer coefficient, Btu/hr-ft^2-°F, associated with the fin surface of j^{th} element of the heat exchanger

h_i = tube side heat transfer coefficient, Btu/hr-ft^2-°F

k_{wall} = thermal conductivity of the tube wall material, Btu/hr-ft-°F

r_{fi} = inside fouling resistance, hr-ft^2-°F/Btu

U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger

η_j = fin efficiency (dimensionless) associated with the fin surface of j^{th} element of the heat exchanger

Since the heat flows from the outside fluid to the inside fluid via the condensate layer and the fins, one can write the following:

$$q_j = \frac{k_{\text{cond}}}{\delta_j}(T_{o,j} - T_{s,j}) \quad \text{(C-7)}$$

$$q_j = h_{\text{out},j}(T_{\infty,j} - T_{o,j}) \quad \text{(C-8)}$$

$$q_j = U_j(T_{\infty,j} - T_{t,j}) \quad \text{(C-9)}$$

where

$h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft^2-°F, associated with simultaneous heat and mass transfer of j^{th} element of the heat exchanger

k_{cond} = bulk thermal conductivity of the condensate, Btu/hr-ft-°F

q_j = local heat transfer rate per unit outside area, Btu/hr-ft^2, of j^{th} element of the heat exchanger

$T_{\infty,j}$ = temperature, °F, of bulk fluid around the tubes of j^{th} element of the heat exchanger

$T_{o,j}$ = temperature of gas–condensate interface, °F, of j^{th} element of the heat exchanger

$T_{s,j}$ = local average temperature, °F, of outside heat transfer surface of j^{th} element of the heat exchanger

$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger

U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger

δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger

The local heat transfer rate per unit outside area is equal to the sum of convective heat transfer rate per unit area and the energy release rate per unit area associated with the condensation of vapor. Therefore,

$$q_j = h_j(T_{\infty,j} - T_{o,j}) + (N_{A,j})(h_{ig})(M_A) \quad \text{(C-10)}$$

and

$$T_{\infty,j} = \tfrac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) \quad \text{(C-11)}$$

$$T_{\text{cond},j} = \tfrac{1}{2}(T_{o,j} + T_{s,j}) \quad \text{(C-12)}$$

where

h_{fg} = heat of condensation of the vapor, Btu/lbm

h_j = outside heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger adjusted for high mass transfer rate associated with sensible heat transfer only

M_A = molecular weight of the vapor, lbm/lbm-mole

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

q_j = local heat transfer rate per unit outside area, Btu/hr-ft^2, of j^{th} element of the heat exchanger

$T_{\text{cond},j}$ = condensate temperature, °F, of j^{th} element of the heat exchanger

$T_{\infty,j}$ = temperature, °F, of bulk fluid around the tubes of j^{th} element of the heat exchanger

$T_{\infty 1,j}$ = temperature, °F, of the air–vapor mixture upstream of the tube row of j^{th} element of the heat exchanger

$T_{\infty 2,j}$ = temperature, °F, of the air–vapor mixture downstream of the tube row of j^{th} element of the heat exchanger

$T_{o,j}$ = temperature of gas–condensate interface, °F, of j^{th} element of the heat exchanger

$T_{s,j}$ = local average temperature, °F, of outside heat transfer surface of j^{th} element of the heat exchanger

The mass transfer rate per unit outside area is related to vapor partial pressure difference by the mass transfer coefficient as follows:

$$N_{A,j} = k_{A,j} \ln\left(\frac{p_{\text{tot}} - p_{A,o,j}}{p_{\text{tot}} - p_{A,\infty,j}}\right) \quad \text{(C-13)}$$

$$p_{A,\infty,j} = \frac{1}{2}\left(p_{A,\infty 1,j} + p_{A,\infty 2,j}\right) \tag{C-14}$$

where

$k_{A,j}$ = mass transfer coefficient, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger not adjusted for high mass transfer rate

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

$p_{A,\infty,j}$ = average vapor partial pressure, psia, in the bulk fluid of j^{th} element of the heat exchanger

$p_{A,\infty 1,j}$ = vapor partial pressure, psia, upstream of the tube row of j^{th} element of the heat exchanger

$p_{A,\infty 2,j}$ = vapor partial pressure, psia, downstream of the tube row of j^{th} element of the heat exchanger

$p_{A,o,j}$ = saturation pressure, psia, of the vapor at temperature T_o of j^{th} element of the heat exchanger

p_{tot} = pressure, psia, of the vapor–air mixture

The local convective heat transfer coefficient is altered by the local mass flux and is given as follows:

$$\dot{h}_j = \frac{N_{A,j}C_A}{1 - e^{-(N_{A,j}C_A/h_j)}} \tag{C-15}$$

where

C_A = molar specific heat, Btu/lbm-mole-°F, of pure vapor

h_j = outside heat transfer coefficient, Btu/hr-ft^2-°F, in noncondensing situation of j^{th} element of the heat exchanger

$\dot{h}_j$ = outside heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger adjusted for high mass transfer rate associated with sensible heat transfer only

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

Assuming that thermodynamic equilibrium exists at the gas–condensate interface, the vapor partial pressure at the interface is equal to the vapor pressure of the liquid at the interface temperature as follows:

$$p_{A,o,j} = p_{\text{sat}(T_{o,j})} \tag{C-16}$$

where

$p_{A,o,j}$ = partial pressure, psia, of the vapor at the gas–liquid interface of j^{th} element of the heat exchanger

$p_{\text{sat}(T_{o,j})}$ = saturation pressure, psia, of the vapor corresponding to $T_{o,j}$

$T_{o,j}$ = temperature of gas–condensate interface, °F, of j^{th} element of the heat exchanger

The relationship between vapor partial pressure and vapor mass fraction can be expressed as follows:

$$\phi_{1,j} = \frac{M_A}{M_{da}}\left(\frac{p_{A,\infty 1,j}}{p_{\text{tot}} - p_{A,\infty 1,j}}\right) \tag{C-17}$$

$$\phi_{2,j} = \frac{M_A}{M_{da}}\left(\frac{p_{A,\infty 2,j}}{p_{\text{tot}} - p_{A,\infty 2,j}}\right) \tag{C-18}$$

where

M_A = molecular weight of the vapor, lbm/lbm-mole

M_{da} = molecular weight of dry air, lbm/lbm-mole

$p_{A,\infty 1,j}$ = vapor partial pressure, psia, upstream of the tube row of j^{th} element of the heat exchanger

$p_{A,\infty 2,j}$ = vapor partial pressure, psia, downstream of the tube row of j^{th} element of the heat exchanger

p_{tot} = pressure, psia, of the vapor–air mixture

$\phi_{1,j}$ = vapor-to-dry air mass ratio of j^{th} element of heat exchanger upstream of tube row

$\phi_{2,j}$ = vapor-to-dry air mass ratio of j^{th} element of heat exchanger downstream of tube row

The heat transfer coefficient associated with the outside heat transfer surface can be expressed in terms of outside fouling resistance, condensate layer resistance, and the outside convective resistance. Therefore,

$$\frac{1}{h_{\text{fin},j}} = \frac{1}{h_{\text{out},j}} + r_{j,o} + \frac{\delta_j}{k_{\text{cond}}} \tag{C-19}$$

where

$h_{\text{fin},j}$ = heat transfer coefficient, Btu/hr-ft^2-°F, associated with the fin surface of j^{th} element of the heat exchanger

$h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft^2-°F, associated with simultaneous heat and mass transfer of j^{th} element of the heat exchanger

k_{cond} = bulk thermal conductivity of the condensate, Btu/hr-ft-°F

$r_{f,o}$ = outside fouling resistance, hr-ft^2-°F/Btu

δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger

Note, h_{fin} should be used to calculate fin efficiency (refer to para. C-2.1.8).

The condensate layer flows vertically downwards along the fin surface. Its thickness can be calculated using the following expression:

$$\delta_j = \frac{3}{4}\left[\frac{3\mu N_{A,j}M_A L}{\rho_l(\rho_l - \rho_v)g}\right]^{1/3} \tag{C-20}$$

where

g = acceleration due to gravity, ft/hr^2

L = vertical length, ft, of fins over which condensate layer slides

M_A = molecular weight, lbm/lbm-mole, of the vapor

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger

μ = viscosity, lbm/hr-ft, of the condensate

ρ_1 = density, lbm/ft^3, of the condensate

ρ_v = density, lbm/ft^3, of the air–vapor mixture

The mass transfer coefficient can be evaluated using the analogy between heat transfer and mass transfer. This relationship is as follows:

$$k_A = \frac{h}{C}\left(\frac{\text{Pr}}{\text{Sc}}\right)^{2/3} \tag{C-21}$$

where

C = molar specific heat, Btu/lbm-mole-°F, of the air-vapor mixture

h = outside heat transfer coefficient, Btu/hr-ft^2-°F, in noncondensing situation

k_A = mass transfer coefficient, lbm-mole/hr-ft^2, not adjusted for high mass transfer rate

Pr = Prandtl number of the air–vapor mixture (dimensionless)

Sc = Schmidt number of the air–vapor mixture (dimensionless)

It is clear from the above equations that the humid air outlet enthalpy and vapor mass fraction are functions of the distance from the vapor inlet, "x." The mixed mean outlet temperature of the humid air can be related to the mixed mean values of outlet enthalpy and vapor mass fraction. The expressions of humid air mixed mean outlet enthalpy and vapor mass fraction are as follows:

$$e_{\text{out}} = \frac{1}{N}\sum_{j=1}^{N} e_{2,j} \tag{C-22}$$

$$\phi_{\text{out}} = \frac{1}{N}\sum_{j=1}^{N} \phi_{2,j} \tag{C-23}$$

where

$e_{2,j}$ = enthalpy, Btu/lbm of dry air, of the air–vapor mixture downstream of the tube row of j^{th} element of the heat exchanger

e_{out} = enthalpy, Btu/lbm of dry air, of the air–vapor mixture at the outlet

N = number of elements into which the heat exchanger has been subdivided

$\phi_{2,j}$ = vapor-to-dry air mass ratio downstream of the tube row of j^{th} element of the heat exchanger

ϕ_{out} = vapor-to-dry air mass ratio at the outlet

The mixed mean outlet temperature of humid air is related to the mixed mean outlet enthalpy and mixed mean outlet vapor mass fraction. This is shown symbolically by the following relationship:

$$T_{\infty,\text{out}} = f_2(e_{\text{out}}, \phi_{\text{out}}) \tag{C-24}$$

where

e_{out} = enthalpy, Btu/lbm of dry air, of the air–vapor mixture at the outlet

f_2 = functional operator 2

$T_{\infty,\text{out}}$ = mixed mean temperature, °F, of the air–vapor mixture at the outlet

ϕ_{out} = vapor-to-dry air mass ratio at the outlet

C-3.3 Solve the Finite Difference Equations and Evaluate Fouling Resistance

The 24 equations shown in para. C-3.2 have to be solved simultaneously to evaluate the tube side fouling resistance. The following variables are known from the test: $T_{t,\text{in}}$; $T_{\infty 1}$; $p_{\infty 1}$; W_t ; $T_{t,\text{out}}$; $T_{\infty,\text{out}}$; and p_{tot}.

The solution of finite difference eqs. (C-1) through (C-3) and (C-5) requires the overall heat transfer coefficient, U, as a function of location within the heat exchanger. The equations are nonlinear because the coefficients themselves depend on the unknown variables. Therefore, these equations require iterative techniques for their simultaneous solution.

The overall procedure is to assume a tube side fouling resistance and dry-airflow rate. The combination of these two values that matches with the two measured outlet temperatures is the proper airflow rate and tube side fouling resistance.

C-4 TRANSIENT TEST METHOD

The steady-state temperature profiles of fluids inside a shell-and-tube heat exchanger during steady state can be represented by a set of ordinary differential equations. These equations can be integrated when specific heat is constant and when the overall heat transfer coefficient is uniform over the entire heat transfer surface. After integration, the relationship between boundary temperatures, flow rates, specific heat, overall heat transfer coefficient, and the heat transfer area are usually presented in a F-P chart or P-N chart with R as a parameter (see section C-2).

When a heat exchanger undergoes a transient, the temperature profile of shell and tube side fluids can be represented by a set of partial differential equations. For certain simple boundary conditions, these equations may be amenable to direct closed form solution. However, for arbitrarily specified time-dependent boundary conditions of fluid inlet temperatures or flow rates, a numerical integration must be performed.

To integrate the partial differential equations, the initial condition of the temperatures, in addition to the boundary conditions, are needed.

In the example that follows, the applicable set of finite difference equations, the required test data, and data evaluation procedure are presented for a simplified shell-and-tube heat exchanger. A similar process would be followed for a plate heat exchanger.

C-4.1 Establish the Initial Conditions

Before the difference equations obtained in para. C-4.2 can be solved, the initial conditions (the fluid temperature profiles inside the heat exchanger) must be established. This can be done in one of the following two ways depending on whether the hot fluid flow can be stopped or not.

C-4.1.1 Process (Hot) Fluid Flow Can Be Stopped. Stop the flow of the process fluid through the heat exchanger and watch the inlet and outlet temperatures of the cooling fluid. The inlet temperature of the cooling fluid must be constant. When the outlet temperature of the cooling fluid becomes equal to the inlet temperature, the entire heat exchanger is at the cooling fluid inlet temperature and this is the initial condition.

C-4.1.2 Process (Hot) Fluid Flow Cannot Be Stopped. If the process fluid cannot be stopped, then the heat exchanger must operate at a steady-state condition before the transient testing begins. Under these conditions, the initial temperature profiles at the beginning of transient testing can be obtained by solving the difference equations using any reasonable initial conditions for a long enough period so that a steady state is achieved. The temperature distribution thus calculated will provide the initial conditions for the transient test. In this situation, the cooling fluid is usually stopped, the process fluid loop is allowed to heat up, and the cooling fluid is reinitiated. The initial steady-state condition would normally exist just before the cooling fluid is stopped.

Alternatively, the initial conditions can be established by solving the steady-state differential equations.

If the process fluid flow can be stopped, then this method of establishing the initial conditions should be chosen. In this way, the initial conditions can be directly measured from the test and another calculation is not needed.

C-4.2 Collect the Temperature and Flow Rate Data

C-4.2.1 Record the following four parameters:

(a) cooling fluid inlet temperature time history
(b) process fluid inlet temperature time history
(c) cooling fluid flow rate time history
(d) process fluid flow rate time history

C-4.2.2 In addition, record one of the following two parameters:

(a) cooling fluid outlet temperature time history
(b) process fluid outlet temperature time history

If both outlet temperature time histories are measured, then the second outlet temperature can be used as a check.

CAUTION: It is desirable to have steady flow rates. However, if it is not possible, then the heat transfer coefficient needs to be calculated at each time step.

C-4.3 Write the Finite Difference Equations

Write the governing equations in the finite difference form. However, if one wishes to obtain a closed form solution, then one would need to write the differential equations. A closed form solution may not be obtainable in many instances. Under these conditions, a numerical solution of the finite difference equations is the only alternative.

Figure C-3 shows a one-tube pass and one-shell pass countercurrent flow heat exchanger. Figure C-4 shows an infinitesimal element of this heat exchanger bounded by two parallel planes normal to the length of the heat exchanger. The following finite difference equations based on the energy conservation equation and the definition of the overall heat transfer coefficient can be written for the shell and tube side flows. The governing equations for other types of arrangements can be written in a similar way using the procedure described here as a guide.

NOTE: The following equations are dimensionally consistent, and any dimensionally consistent set of units may be used.

For the shell side fluid in the j^{th} element the rate of increase of stored energy is as follows:

$$\Delta(mc)_s\left[\frac{T_{s,j}^{\ p+1} - T_{s,j}^{\ p}}{\Delta t}\right]$$

where

$T_{s,j}^{\ p}$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step
$T_{s,j}^{\ p+1}$ = temperature of the shell side fluid in the j^{th} element at the $(p + 1)^{\text{th}}$ time step
$\Delta(mc)_s$ = summation of stored mass and specific heat of the components associated with the shell side flow divided by the number of elements into which the heat exchanger has been divided; these elements are the shell, shell side fluid, and half of the tube wall (the other half of the tube wall thermal inertia is part of the tube side fluid)
Δt = time step size

The rate of energy entering from the shell side of the $(j - 1)^{\text{th}}$ element is as follows:

$$(WCp)_s(T_{s,j-1}^{\ p})$$

where

$T_{s,j-1}^{\ p}$ = temperature of the shell side fluid in the $(j - 1)^{\text{th}}$ element at the p^{th} time step

Fig. C-3 Schematic Representation of a Countercurrent Shell-and-Tube Heat Exchanger

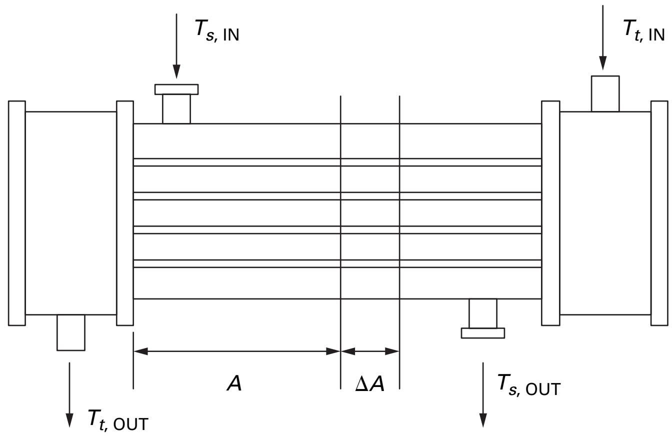
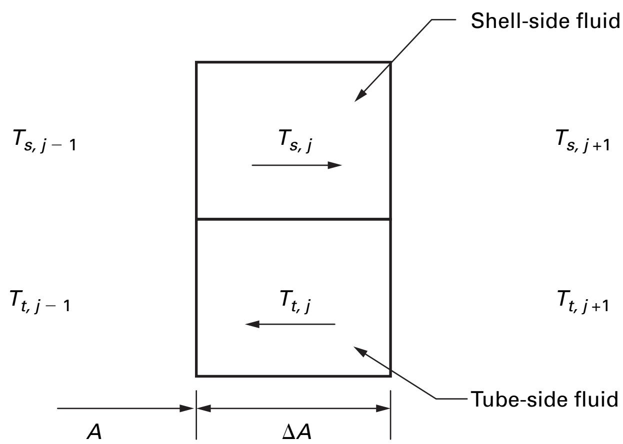


Fig. C-4 A Small Element of a Countercurrent Shell-and-Tube Heat Exchanger



$(WCp)_s$ = product of the shell side mass flow rate and the specific heat

The rate of energy exiting out of the shell side of the j^{th} element is as follows:

$$(WCp)_s(T_{s,j}{}^p)$$

where
$T_{s,j}{}^p$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step
$(WCp)_s$ = product of the shell side mass flow rate and the specific heat

The rate of energy transfer to the tube side flow in the j^{th} element is as follows:

$$U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p)$$

where
$T_{s,j}{}^p$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step
$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step
U = overall heat transfer coefficient, referred to the outside area; this could vary with time if the flow rate is also varying with time
ΔA = total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been divided

From the law of conservation of energy,

$$(WCp)_s T_{s,j-1}{}^p = (WCp)_s T_{s,j}{}^p + \Delta(mc)_s\left[\frac{T_{s,j}{}^{p+1} - T_{s,j}{}^p}{\Delta t}\right] + U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p)$$

where all the variables are defined above.

Solving for the unknown temperature,

$$T_{s,j}{}^{p+1} = \frac{(WCp)_s(\Delta t)}{\Delta(mc)_s}\,T_{s,j-1}{}^p + \left[1 - \frac{[(WCp)_s + U(\Delta A)]\Delta t}{\Delta(mc)_s}\right]T_{s,j}{}^p + \frac{U(\Delta A)\Delta t}{\Delta(mc)_s}\,T_{t,j}{}^p;\ 1 \le j \le N \qquad \text{(C-25)}$$

where all variables are as defined above.

From the shell side inlet boundary condition,

$$T_{s,0}{}^p = T_{s,\text{in}}{}^p \qquad \text{(C-26)}$$

where

$T_{s,\text{in}}{}^p$ = inlet temperature of the shell fluid at the p^{th} time step
$T_{s,\text{O}}{}^p$ = temperature of the shell side fluid upstream of the first heat exchanger element at the p^{th} time step

For the tube side fluid in the j^{th} element, the rate of increase of stored energy is as follows:

$$\Delta(mc)_t\left[\frac{T_{t,j}{}^{p+1} - T_{t,j}{}^p}{\Delta t}\right]$$

where
$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step
$T_{t,j}{}^{p+1}$ = temperature of the tube side fluid in the j^{th} element at the $(p + 1)^{\text{th}}$ time step
$\Delta(mc)_t$ = summation of stored mass and specific heat of the components associated with the tube side flow divided by the number of elements into which the heat exchanger has been divided; these elements are the tube side fluid and half of the tube wall (the other half of the tube wall thermal inertia is part of the shell side fluid)
Δt = time step size

The rate of energy entering from the tube side of the $(j + 1)^{\text{th}}$ element is as follows:

$$(WCp)_t T_{t,j+1}{}^p$$

where
$T_{t,j+1}{}^p$ = temperature of the tube side fluid in the $(j + 1)^{\text{th}}$ element at the p^{th} time step
$(WCp)_t$ = product of the tube side mass flow rate and the specific heat

The rate of energy exiting out of the tube side of the j^{th} element is as follows:

$$(WCp)_t T_{t,j}{}^p$$

where
$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step
$(WCp)_t$ = product of the tube side mass flow rate and the specific heat

The rate of energy transfer from the shell side fluid of the j^{th} element is as follows:

$$U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p)$$

where
$T_{s,j}{}^p$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step
$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step
U = overall heat transfer coefficient, referred to the outside area (this could vary with time if the flow rate is also varying with time)
ΔA = total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been divided

From the law of conservation of energy,

$$(WCp)_t T_{t,j+1}{}^p + U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p) = (WCp)_t T_{t,j}{}^p + \Delta(mc)_t\left[\frac{T_{t,j}{}^{p+1} - T_{t,j}{}^p}{\Delta t}\right]$$

Solving for the unknown temperature,

$$T_{t,j}{}^{p+1} = \frac{(WCp)_t\,(\Delta t)}{\Delta(mc)_t}\,T_{t,j+1}{}^p + \left[1 - \frac{[(WCp)_t + U(\Delta A)]\Delta t}{\Delta(mc)_t}\right]T_{t,j}{}^p + \frac{U(\Delta A)\Delta t}{\Delta(mc)_t}\,T_{s,j}{}^p;\ 1 \le j \le N \qquad \text{(C-27)}$$

where the variables are as defined previously.

From the tube side inlet boundary condition,

$$T_{t,N+1}{}^p = T_{t,\mathrm{IN}}{}^p \qquad \text{(C-28)}$$

where

$T_{t,\mathrm{IN}}{}^p$ = inlet temperature of the tube side fluid at the p^{th} time step

$T_{t,N+1}{}^p$ = temperature of the tube side fluid upstream of the N^{th} element of the heat exchanger at the p^{th} time step

The outlet temperatures are set equal to the temperature in the boundary element, which is just upstream of the outlet. Thus,

$$T_{s,\mathrm{OUT}}{}^{p+1} = T_{s,N}{}^{p+1} \qquad \text{(C-29)}$$

$$T_{t,\mathrm{OUT}}{}^{p+1} = T_{t,1}{}^{p+1} \qquad \text{(C-30)}$$

ΔA and Δt must satisfy the inequalities (C-31) and (C-32) simultaneously to satisfy the stability criteria,

$$\Delta t < \frac{\Delta(mc)_s}{(WCp)_s + U(\Delta A)} \qquad \text{(C-31)}$$

$$\Delta t < \frac{\Delta(mc)_t}{(WCp)_t + U(\Delta A)} \qquad \text{(C-32)}$$

where the variables are as defined previously.

C-4.4 Solve the Finite Difference Equations and Evaluate the Fouling Resistance

The procedure is to guess a value of total fouling resistance, expressed by eq. (C-34) in terms of inside and outside fouling resistances, and calculate the overall heat transfer coefficient, U, using eq. (C-33). If the flow rates are also changing during the transient testing, then the overall heat transfer coefficient would change with time and would need to be calculated at each time step.

$$\frac{1}{U} = \frac{1}{h_o} + r_{f,t} + r_w + \frac{d_o}{d_i}\frac{1}{h_i} \qquad \text{(C-33)}$$

$$r_{f,t} = r_{f,o} + \frac{d_o}{d_i}\,r_{f,i} \qquad \text{(C-34)}$$

where

d_i = tube inside diameter

d_o = tube outside diameter

h_i = inside heat transfer coefficient referred to the inside area

h_o = outside heat transfer coefficient referred to the outside area

$r_{f,i}$ = inside fouling resistance referred to the inside area

$r_{f,o}$ = outside fouling resistance referred to the outside area

$r_{f,t}$ = total fouling resistance referred to the outside surface area

r_w = tube wall resistance referred to the outside area

U = overall heat transfer coefficient, referred to the outside area; this could vary with time if the flow rate is also varying with time

The procedures for calculating h_i, h_o, r_w, etc. are described in detail in section C-2.

Equations (C-25) through (C-30) can be solved to yield temperatures with superscript (p + 1) using the values of temperatures with superscript p. At each time step, the temperatures with superscript p are known and the temperatures with superscript (p + 1) are unknown. At the first time step, all the temperatures are known from initial conditions. Thus, the time histories of both outlet temperatures can be calculated in a step-by-step manner. Repeat the calculations with a smaller time step and finer noding to check for convergence of the calculated outlet temperature time histories. The value of fouling resistance that best matches the measured outlet temperature time histories is the actual fouling resistance of the heat exchanger.

C-5 TEMPERATURE EFFECTIVENESS TEST METHOD

The temperature effectiveness test method is used to calculate a projected temperature of a heat exchanger at a known reference point (typically at the design accident conditions) based on data collected at the test point. The method described below can be applied to a wide variety of heat exchangers, and can be calculated by hand. It assumes that the process and cooling fluid mass flow rates at the test point are essentially the same as those at the reference point (within ±5%). This test method is accomplished by collecting the process and cooling fluid inlet and outlet temperatures at the test point, choosing two temperatures at the reference point, and calculating the remaining two temperatures at the reference point.

C-5.1 Establish Flows

Although the flow rates (cooling fluid and process) are not required to be permanently and accurately measured, since the temperature effectiveness will vary with both flow rates, repeatable flow rates must be established (e.g., same valve lineups, header pressures, pump currents, etc.). Both flows should be within ±5% of the flow rates that were used to establish the acceptance criteria.

C-5.2 Collect the Temperature Data

Record the following temperature data at steady-state conditions. This set of test data will be termed the test point.

$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-5.2.1 Data Set

$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$T_{2,t}$ = 123.4
$t_{2,t}$ = 93.0

C-5.3 Calculate the Capacity Rate Ratio

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$

where

R_t = capacity rate ratio (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-5.3.1 Data Set

R_t = 0.9391
$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$T_{2,t}$ = 123.4
$t_{2,t}$ = 93.0

C-5.4 Calculate the Temperature Effectiveness

$$P_t = (t_{2,t} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = thermal effectiveness (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

The temperature effectiveness is also called the thermal effectiveness or temperature efficiency, and is always a number between 0 and 1.

C-5.4.1 Data Set

P_t = 0.3067
$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$t_{2,t}$ = 93.0

C-5.5 Calculate the Projected Temperatures

Using the capacity rate ratio and temperature effectiveness at the test point (as calculated in paras. C-5.3 and C-5.4) and any two temperatures at the reference point (i.e., any two accident condition temperatures), calculate the two projected temperatures at the reference point (i.e., the other two accident condition temperatures) using the following equations. If the accident condition temperature of interest does not meet the acceptance criteria (refer to section 9), then corrective action is necessary. For the example that follows, the known temperatures and the acceptance criteria (used to compare the calculated temperatures against) are assumed to be the same as para. C-2.1.1.1 data set or as follows:

$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

C-5.5.1 If $T_{1,d}$ and $t_{1,d}$ Are Known

$$t_{2,d} = t_{1,d} + P_t(T_{1,d} - t_{1,d})$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

C-5.5.1.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 121.3[3]
$t_{2,d}$ = 94.93[3]

C-5.5.2 If $T_{1,d}$ and $t_{2,d}$ Are Known

$$t_{1,d} = t_{2,d} + P_t(t_{2,d} - T_{1,d})/(1 - P_t)$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

[3] These values should be compared with the para. C-2.1.1.1 data set, with appropriate consideration of uncertainty.

C-5.5.2.1 Data Set

$P_t = 0.3067$
$R_t = 0.9391$
$T_{1,d} = 140.0$
$t_{1,d} = 77.98^3$
$T_{2,d} = 97.0$
$t_{2,d} = 122.1^3$

C-5.5.3 If $T_{2,d}$ and $t_{1,d}$ Are Known

$$t_{2,d} = t_{1,d} + P_t(T_{2,d} - t_{1,d})/(1 - P_tR_t)$$

$$T_{1,d} = T_{2,d} + R_t(t_{2,d} - t_{1,d})$$

C-5.5.3.1 Data Set

$P_t = 0.3067$
$R_t = 0.9391$
$T_{1,d} = 137.2^3$
$t_{1,d} = 75.0$
$T_{2,d} = 119.3$
$t_{2,d} = 94.08^3$

C-5.5.4 If $T_{2,d}$ and $t_{2,d}$ Are Known

$$t_{1,d} = t_{2,d} + P_t(t_{2,d} - T_{2,d})/(1 - P_tR_t - P_t)$$

$$T_{1,d} = T_{2,d} + R_t(t_{2,d} - t_{1,d})$$

C-5.5.4.1 Data Set

$P_t = 0.3067$
$R_t = 0.9391$
$T_{1,d} = 135.1^3$
$t_{1,d} = 80.13^3$
$T_{2,d} = 119.3$
$t_{2,d} = 97.0$

C-5.5.5 If $T_{1,d}$ and $T_{2,d}$ Are Known

$$t_{1,d} = T_{1,d} + (T_{2,d} - T_{1,d})/R_tP_t$$

$$t_{2,d} = t_{1,d} - (T_{2,d} - T_{1,d})/R_t$$

C-5.5.5.1 Data Set

$P_t = 0.3067$
$R_t = 0.9391$
$T_{1,d} = 140.0$
$t_{1,d} = 68.13^3$
$T_{2,d} = 119.3$
$t_{2,d} = 90.17^3$

C-5.5.6 If $t_{1,d}$ and $t_{2,d}$ Are Known

$$T_{1,d} = t_{1,d} + (t_{2,d} - t_{1,d})/P_t$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

C-5.5.6.1 Data Set

$P_t = 0.3067$
$R_t = 0.9391$
$T_{1,d} = 146.7^3$
$t_{1,d} = 75.0$
$T_{2,d} = 126.1^3$
$t_{2,d} = 97.0$

C-6 BATCH TEST METHOD

The batch test method is used to calculate the temperature effectiveness and overall heat transfer coefficient of a heat exchanger by measuring initial and final process temperatures over a measured time period, while holding the cooling fluid inlet temperature constant. Using the thermal capacity of a reservoir (i.e., the process fluid), the temperature effectiveness and overall heat transfer coefficient can be calculated.

The following example demonstrates the batch test method for a reservoir of process fluid containing 100,000,000 lb of water being cooled from 200°F to 180°F in 20.55 hr. The flow rate of the cooling fluid is 1,000,000 lb/hr and the inlet temperature of the cooling fluid is 60°F. The shell side of the heat exchanger is supplied by the fluid of the reservoir.

NOTE: Although this example is for the cooling of a reservoir containing the process fluid, the methodology for the heating of a reservoir containing the cooling fluid would be similar.

C-6.1 Calculate the Thermal Capacity of the Process Fluid

$$C_{p,t} = (M_{p,t})(Cp_{p,t})$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions
$Cp_{p,t}$ = specific heat of the process fluid, Btu/lbm-°F, at test conditions, from the reference in subpara. 3.2(e)
$M_{p,t}$ = mass of the process fluid, lbm, at test conditions

C-6.1.1 Data Set

$C_{p,t} = 100{,}000{,}000$
$Cp_{p,t} = 1$
$M_{p,t} = 100{,}000{,}000$

NOTE: In the event that the thermal capacity of the process fluid reservoir cannot be ascertained accurately, measuring the heat duty through the heat exchanger as a function of time and integrating it to obtain the total quantity of heat transferred during the period of testing is an acceptable procedure.

C-6.2 Calculate the Temperature Effectiveness

$$P_t = [C_{p,t}/(\tau W_{c,t}Cp_{c,t})] \ln[(T_{1,t,i} - t_{1,t})/(T_{1,t,f} - t_{1,t})]$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions
$Cp_{p,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in subpara. 3.2(e)
P_t = temperature effectiveness (dimensionless) at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions

$T_{1,t,f}$ = final process fluid inlet temperature, °F, at end of time τ at test conditions
$T_{1,t,i}$ = initial process fluid inlet temperature, °F, at beginning of time τ at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions
τ = time required to cool the process fluid, hr

C-6.2.1 Data Set

$C_{p,t}$ = 100,000,000
$Cp_{c,t}$ = 1
$t_{1,t}$ = 60
$T_{1,t,f}$ = 180
$T_{1,t,i}$ = 200
$W_{c,t}$ = 1,000,000
τ = 20.55

Therefore,
$P_t = 0.75$

C-6.3 Calculate the Capacity Rate Ratio

$$R_t = W_{c,t}Cp_{c,t}/W_{p,t}Cp_{p,t}$$

where
$Cp_{c,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in subpara. 3.2(e)
$Cp_{p,t}$ = heat capacity of the process fluid, Btu/lbm-°F, at test conditions from the reference in subpara. 3.2(e)
R_t = capacity rate ratio (dimensionless) at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions
$W_{p,t}$ = mass flow rate of the process fluid, lbm/hr, at test conditions

C-6.3.1 Data Set

$Cp_{c,t}$ = 1
$Cp_{p,t}$ = 1
$W_{c,t}$ = 1,000,000
$W_{p,t}$ = 833,000

Therefore,
$R_t = 1.2$

NOTE: Refer to para. C-5.5 to calculate projected temperatures at design accident conditions, or continue with the next steps to calculate the overall heat transfer coefficient.

C-6.4 Calculate *NTU*

For countercurrent flow

$$NTU_t = [1/(R_t - 1)] \ln[(1 - P_t)/(1 - P_tR_t)]$$

where
NTU_t = number of transfer units (dimensionless) at test conditions
P_t = temperature effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions

NOTE: Equations for *NTU* for other than countercurrent flow configurations are given in the reference in subpara. 3.2(c).

C-6.4.1 Data Set

P_t = 0.75
R_t = 1.2

Therefore,
$NTU_t = 4.58$

C-6.5 Calculate U_t (*NTU* Method)

$$U_t = (NTU_t)(W_{c,t})(Cp_{c,t})/A_{o,t}$$

where
$A_{o,t}$ = effective external surface area, ft^2, at test conditions
$Cp_{c,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in subpara. 3.2(e)
NTU_t = number of transfer units (dimensionless) at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions

C-6.5.1 Data Set

$A_{o,t}$ = 10,000
$Cp_{c,t}$ = 1
NTU_t = 4.58
$W_{c,t}$ = 100,000

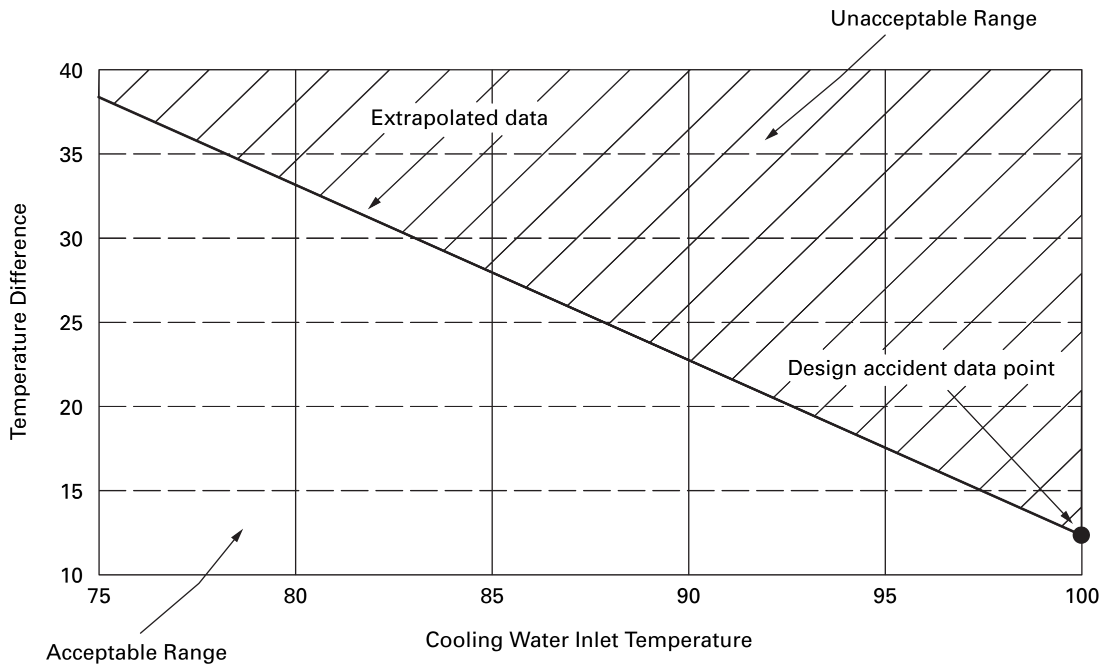
Therefore,
$U_t = 458$

NOTE: For NTU curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, $T_{1,t}$ and $T_{2,t}$ must be for the shell side fluid and $t_{1,t}$, $t_{2,t}$, $W_{c,t}$, and $Cp_{c,t}$ *must* be for the tube side fluid.
Refer to para. C-2.2.7 to calculate (with some additional data) the projected overall heat transfer coefficient and heat transfer rate at design accident conditions.

C-7 TEMPERATURE DIFFERENCE MONITORING METHOD

This example examines a typical emergency diesel generator (EDG) heat exchanger that is depended upon to displace 12.37 million Btu/hr at design basis accident conditions. The design basis of the heat exchanger is such that the process outlet temperature does not exceed 112°F while displacing the required heat transfer. In this instance, the limiting cooling water inlet temperature (CWIT) is assumed to be 100°F at a flow rate of

Fig. C-5 Cooling Water Inlet Temperature Versus Temperature Difference



GENERAL NOTES:
(a) Temperature difference = ΔT
(b) Cooling water inlet temperature = t_1

1,650 gpm. The process flow inlet temperature is 170°F at a flow rate of 450 gpm. The heat exchanger for this example is a single pass, countercurrent flow heat exchanger with 90–10 copper–nickel tubes.

For this example, the temperature of interest is the process fluid outlet temperature, and the terms "tube side" and "cooling water" are used interchangeably.

CAUTION: In reality, the EDG might employ a temperature control valve to modulate process flow to the heat exchanger to prevent too much or too little heat from being removed if it detected a process fluid temperature outside a specified range. If this were to occur, significant changes in the process flow may influence the resulting process fluid outlet temperature, the rate of heat transfer, as well as the cooling water outlet temperature. Significant deviations in the process flows, heat load, and process inlet temperature may invalidate the use of this monitoring method unless their effects are taken into consideration.

Since seasonal influences may significantly affect the cooling water inlet temperature, it may be desirable to establish a correlation that can be used to bound the acceptable operating range of the heat exchanger as the cooling water inlet temperature varies with the season, as shown in Fig. C-5.

Figure C-5 shows that the temperature difference between the process fluid outlet temperature and the cooling water inlet temperature may be increased significantly above the 13.73°F value as the cooling water inlet temperature decreases. Additionally, this figure is based on the heat exchanger supplying the required heat transfer of 12.37 million Btu/hr, with the process fluid inlet temperature at 170°F and with the process flow and the cooling water flow rates at 450 gpm and 1,650 gpm, respectively. For example, at 90°F, the baseline cleanliness test revealed a temperature difference of 3.44°F. By using this correlation, the temperature difference can be allowed to increase to approximately 23°F before the heat exchanger would traverse the point where it would no longer satisfy its performance requirements.

The heat exchanger tube resistance (and resulting temperature difference) is permitted to increase as the cooling water inlet temperature decreases for the reason that the performance of the heat exchanger meets its design basis heat transfer requirements. In this example, a tube resistance of 0.006624 hr-ft^2-°F/Btu would be permitted provided that the CWIT was equal to or less than 75°F. With a CWIT of 85°F, the limiting tube resistance becomes 0.005205 hr-ft^2-°F/Btu. Furthermore, as the CWIT increases to the design basis temperature of 100°F, the limiting tube resistance is further reduced to 0.002962 hr-ft^2-°F/Btu.

CAUTION: As the cooling water inlet temperature starts an upward trend, the degree of operating margin will be reduced in a corresponding manner and experience will be the best guide

to dictate corrective actions in a timely manner. In this example, the operating margin may be the difference between the limiting CWIT as determined by the current temperature difference ($T_2 - t_1$) and the actual CWIT, t_1.

The procedure for this example is given below.

C-7.1 Calculate the Temperature Difference at Design Accident Conditions

$$\Delta T_d = T_{2,d} - t_{1,d}$$

where

$t_{1,d}$ = cooling fluid inlet temperature, °F, at design accident conditions

$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions

ΔT_d = temperature difference, °F, at design accident conditions

C-7.1.1 Data Set

$t_{1,d}$ = 100

$T_{2,d}$ = 112

ΔT_d = 12

C-7.2 Plot the Design Accident Condition Data

Plot the data point corresponding to $t_{1,d}$ and ΔT_d, as shown in Fig. C-5.

(15) C-7.3 Extrapolate the Design Data to Determine the Acceptable Range

Extrapolate the design data to determine the acceptable range of temperature difference (ΔT) when cooler weather causes a drop in the cooling water inlet temperature (CWIT or t_1). This acceptable range (as shown in Fig. C-5) will be used as a tool to gauge future tests.

The extrapolation of the limiting temperature difference corresponding with the lowest anticipated cooling inlet water is derived using a heat balance $Q = \dot{m}Cp\Delta T = UA(LMTD)$. The cooling water outlet temperature and the shell side outlet temperature are solved using the above heat balance. The shell and tube side flows, as well as the design fouling resistance, are considered constant over the range of the extrapolation. The heat transfer will increase as the cooling water inlet temperature decreases. The unknowns are the shell side outlet temperature and the tube side outlet temperature.

For Fig. C-5, the tube side flow rate is 1,650 gpm and the shell side flow rate is 450 gpm. The shell side inlet temperature is 170°F and the tube side resistance is 0.002962 hr-ft^2-°F/Btu. At the cooling water inlet temperature corresponding to 100°F, the tube side outlet temperature and the shell side outlet temperature were determined to be 115.19°F and 113.73°F, respectively. At the cooling water inlet temperature corresponding to 75°F, the tube side outlet temperature and the shell side outlet temperature were determined to be 95.29°F and 94.37°F, respectively. Once the shell side outlet temperatures are determined, the value of the temperature difference corresponding to a selected cooling water inlet temperature may be determined and plotted.

C-7.4 Calculate the Temperature Difference at Test Conditions

$$\Delta T_t = T_{2,d} - t_{1,t}$$

where

$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions

$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions

ΔT_t = temperature difference, °F, at test conditions

C-7.4.1 Data Set

$t_{1,t}$ = 85

$T_{2,d}$ = 112

ΔT_t = 27

This temperature difference at test conditions should be calculated at appropriate intervals to assess the fouling tendency of the heat exchanger and to indicate the potential need for corrective actions. Generally, a lower temperature difference indicates a cleaner heat exchanger.

C-7.5 Plot the Test Data Against the Design Data

Plotting the data point corresponding to the CWIT at test conditions, $t_{1,t}$, and the temperature difference at test conditions, ΔT_t, will reveal that the heat exchanger is closely approaching its limit in transferring the required amount of heat, even in cooler than normal weather. If the CWIT were to increase several degrees, there is a good chance that the heat exchanger would be unable to perform acceptably.

CAUTION: The ability to take advantage of the margin gained during cooler weather may be prevented by the wording in the FSAR or other design documents.

C-8 PRESSURE LOSS MONITORING METHOD

The methodology used in the example given below involves determining the corrected pressure loss for a given heat exchanger. When applying this method, it is important to remember that the type of fouling present in the heat exchanger can significantly affect the sensitivity of this method (see Nonmandatory Appendix B of this Part, section B-11).

C-8.1 Establish Flow and Collect Flow Data

A steady-state flow should be established through the heat exchanger as close to the same flow rate that was used to establish the acceptance criteria as possible. Small differences between the test flow rate and the acceptance criteria flow rate can be corrected in the calculation.

C-8.2 Collect the Pressure Loss Data

Using a differential pressure gauge, record the pressure loss at steady-state conditions, as described in para. C-8.1.

C-8.3 The Corrected Pressure Loss

Since the pressure loss varies with flow rate, it must be corrected from the test flow rate to the acceptance criteria flow rate from which the acceptance criteria was derived.

C-8.3.1 Calculate the Corrected Pressure Loss (PL_c)

$$PL_c = (W_a/W_t)^n(PL_t)$$

where

n = 2.0 if test flow rate is in the turbulent regime
= 1.8 if test flow rate is in the turbulent regime and if the pressure loss is primarily due to frictional losses in flow through the tubes, rather than entrance/exit losses
= 1.0 if test flow rate is in the laminar regime

PL_c = pressure loss (same units as PL_t), corrected to the acceptance criteria flow rate

PL_t = pressure loss (same units as PL_c), averaged from data collected at test conditions

W_a = acceptance criteria flow rate (same units as W_t), on which the acceptance criteria is based

W_t = test flow rate (same units as W_a), as measured at test conditions

CAUTION: Both W_a and W_t must be in the same flow regime.

CAUTION: See Nonmandatory Appendix B of this Part for conditions that may cause misleading results.

C-8.4 Calculate the Average Corrected Pressure Loss

Calculate the average PL_c and compare it to the acceptance criteria.

C-9 VISUAL INSPECTION MONITORING METHOD

All inspections should be performed by individuals proficient in corrosion processes, heat transfer, chemistry, materials, operating conditions, etc., and possessing a working knowledge in the general preventive maintenance of heat exchangers. Inspectors must be trained to look for more than just gross fouling and/or blockage and may be required to obtain samples for laboratory analysis. It is good practice to have a fouling/corrosion control program that locates fouling, characterizes and determines the effects on the heat exchangers, and trends the data for predicting performance.

The best time to perform the inspection is immediately following disassembly, since the thickness of many biofilm layers is significantly reduced when they are in a dry condition and can appear as a deceptively thin layer. One method to ensure accurate film thickness measurement is to remove a sample tube section from the bundle and cap the ends of the fluid-filled tube for transporting to the laboratory for evaluation.

It should be noted that visual inspection cannot determine the integrity of the tube material and should not be substituted for the predictive monitoring program where eddy current testing or other nondestructive examination (NDE) methods are used. In most cases, eddy current testing can determine the integrity of the tube material but should not be used to determine fouling conditions. A combination of visual inspection and eddy current testing of the tube IDs is recommended where tube wall degradation is suspected.

C-9.1 Inspection Types

Visual inspections can be performed on shell- and tube-type as well as plate-type heat exchangers. Each type of heat transfer surface requires a different type of inspection. These inspection types are described below.

C-9.1.1 Tube Side Inspections. Upon opening the heat exchanger, the inspector should observe and note the amount and type of fouling and debris/sludge present in the heat exchanger, end bells, and tubes. The inspector should obtain samples for laboratory analysis, if required. Special attention should be given to any tube openings that may be plugged by foreign material. Plugged tubes result in removing heat transfer surface and may reduce heat transfer capability (sometimes, if the conditions are right, plugged tubes can result in increased velocity through the tubes, which offsets the effects due to the reduction in heat transfer surface area). The inspection should also be conducted to assess for structural damage, welds, significant wall thinning due to erosion and/or corrosion, tube plug integrity, tube sheet ligaments, and other discrepancies that might affect heat exchanger performance.

The tubes should be visually inspected to determine their condition from the standpoint of both cleanliness and corrosion. Most detailed visual inspections can be conducted using such inspection devices as borescopes, fiberscopes, or video probes.

The most effective method of removing any fouling deposit should be assessed after determining its nature. If pitting is observed, evaluate the need for other NDE to ascertain tube integrity status and possible corrective action.

C-9.1.2 Shell Side Inspections. The shell side normally carries the process fluid, which is usually a closed system and is treated with chemicals to maintain adequate water quality and minimize fouling. However, where the cooling fluid is routed through the shell side, where there has been in-leakage from the cooling water side, or where poor water treatment has contaminated the normally clean side, there is sufficient potential for shell side fouling. This presents additional challenges for inspecting and cleaning, since the outer tube surfaces interface with other structural components (i.e., support plates, and impingement plates) creating areas that may be inaccessible for direct visual inspection.

Fixed tube sheet bundles cannot be removed from their shells easily; therefore, it is necessary to look into the bundle through shell penetrations using either a video probe or a fiberscope, or by removing a tube or section of tube to determine the extent of fouling.

C-9.1.3 Plate Inspections. The basic design of plate-type heat exchangers allows easy access to both the cooling and process fluid sides when disassembled. Limited inspection, without total disassembly, for fouling, corrosion, and debris can be performed by removing inspection plates after draining the heat exchanger. This allows for visual inspection of the inlet and outlet headers and the entrance area to the plate openings by use of inspection devices.

C-9.2 Monitoring Techniques

In addition to direct visual inspection of heat exchanger components, the indirect monitoring techniques described below may be used to detect performance changes via disassembly, fiberscopes, and robotics.

C-9.2.1 Side Stream Monitor. Use of side stream heat exchanger inspections can be employed if accurate and dependable correlations between the side stream heat exchanger and the represented heat exchanger(s) can be established. Such correlations would need to be established for both operating conditions and fouling tendencies (unless both were known to be identical). If inspection results of the representative or side stream heat exchanger identify the need for corrective action, it should be applied to all the representative heat exchangers.

C-9.2.2 Water Quality Monitor. One of the key ingredients of a program to ensure that heat exchangers will maintain their ability to transfer the appropriate amount of heat is adequate water quality. Inspection results will usually be a direct indication of the effectiveness of the applied water treatment. Close monitoring of water quality can be used to predict changes in heat exchanger performance. Thus, the solution for a fouled heat exchanger may simply be to make adjustments in the water treatment process.

C-9.2.3 Infrared Viewer. If the heat exchanger is not heavily insulated, an infrared viewer can be used to identify hot and cold spots within the heat exchanger shell, which may be caused by blocked tube passes, uneven flow distribution, etc. Such data collected and trended over time can be used to detect changes in heat exchanger thermal performance.

C-10 PARAMETER TRENDING

The following are examples of parameters that may be trended.

C-10.1 Test Parameters

If the acceptance criteria can be quantified, and if enough historical data is available (a minimum of three previous test results), then trending of calculated test parameters can be used to determine a projected degradation rate. This will help to ensure operability between scheduled tests.

The following test parameters may be trended to detect heat exchanger performance degradation over time.

C-10.1.1 Fouling Resistance. The fouling resistance, as calculated by the heat transfer coefficient test method, may be trended as an excellent indicator of heat exchanger degradation due to surface fouling. Scheduling of cleaning to maintain acceptable performance is facilitated by trending this calculated parameter.

C-10.1.2 Overall Heat Transfer Coefficient. The overall heat transfer coefficient, as calculated by the heat transfer coefficient test method, may be trended as an excellent indicator of heat exchanger degradation due to surface fouling. The overall heat transfer coefficient is not as sensitive a trending indicator as fouling resistance, because it includes the effects of numerous thermal resistances that do not change with time, but it provides a better direct indication of heat exchanger capability than any of the indicators given below.

C-10.1.3 Temperature Effectiveness. The temperature effectiveness, as calculated by the temperature effectiveness test method, may be trended to provide an indication of possible degradation of the heat exchanger. Although not as sensitive an indicator as the fouling resistance, temperature effectiveness is a reliable indicator of heat transfer performance of the heat exchanger.

C-10.2 Monitored Parameters

C-10.2.1 Pressure Loss. Pressure loss across a heat exchanger, although not a direct indicator of heat transfer capability, is a reliable indicator of fouling caused by the blockage of the heat exchanger flow passages and a weaker indicator of fouling caused by the buildup of scales and films on the heat transfer surface. Sharp increases in pressure loss, readily detectable from trending against time, indicate the onset of fouling due to blockage and either the immediate or future need for inspection and/or cleaning.

C-10.2.2 Temperature Difference. Temperature difference is influenced by normal heat loads and may not be effective for trending.

C-10.3 Other Parameters

C-10.3.1 Temperature. Trending of the component or area temperatures measured by the functional test method, the heat exchanger fluid exit temperatures, or the temperature difference across the heat exchanger provides a useful indication of heat exchanger performance. If inlet temperatures remain constant, measurement of either outlet temperature is an appropriate trending parameter.

C-10.3.2 Temperature Deviation. The deviation of the measured safety-related temperature, as determined by the temperature difference method, from that predicted by the correlation for the measured cooling fluid inlet temperature, may be trended to identify degradation of the heat exchanger.

C-10.3.3 Flow. Flow through a heat exchanger is a less sensitive indicator (than pressure loss) of flow passage fouling. Trending of flow against time, however, may be useful in diagnosing other time-related changes in heat exchanger performance. Where the manufacturer has stated the functionality of a heat exchanger based on a given amount of flow (as in motor and oil coolers), trending flow may be used to monitor heat exchanger performance relative to the minimum flow required.

If flow is trended, then the throttling valves used to control flow to the heat exchanger (indeed, to all heat exchangers on that same train), each time data is gathered, must be in the same position as they would for the "emergency" condition, with automatically operated valves placed in manual. Whatever flow is measured is the flow to be compared with the acceptance criteria. In other words, a flow balance must be achieved.

C-10.3.4 Limiting Cooling Water Inlet Temperature. For heat exchangers with generally small operating margins, the calculated limiting cooling water inlet temperature (LCWIT) is compared to the actual cooling water inlet temperature (CWIT). The difference between the limiting temperature and the actual temperature represents the operating margin and decreases as fouling increases and/or the actual inlet temperature increases.

C-11 UNCERTAINTY ANALYSIS

A summary of the standard statistical method outlined in the references in subparas. 3.2(n) through (p) of this Part, tailored specifically to heat exchanger performance evaluation, is provided below. It accounts for both measurement errors and result sensitivities. It is assumed that the measurement and test conditions lend to treating this data as a normal distribution.

C-11.1 Measurement Errors

The measurement error consists of instrument bias (fixed), precision (random), and spatial errors. A conventional method for calculating measurement errors is summarized below.

The measurement error for each measurement parameter shall be determined as follows:

(a) Combine the bias error and the precision error for the measurement parameter using the square root sum of the squares method.

(b) Repeat the step in subpara. (a) above for each measurement parameter.

For additional details on measurement errors, instrument accuracies, and related topics, see the references in subparas. 3.2(n) through (p) of this Part.

C-11.1.1 Bias Errors. The bias error for each measurement parameter may be determined as follows:

(a) Determine the bias errors associated with each sensor, signal conditioner, and piece of data acquisition equipment in the measurement parameter string. These errors will typically come from manufacturer's reports and calibration capabilities.

(b) Combine these individual bias errors using the square root sum of the squares method for independent errors and then add any dependent errors. The result will be the bias error for that measurement parameter.

(c) Repeat the steps in subparas. (a) and (b) above for each measurement parameter.

Determination of the bias errors should be performed prior to the formal collection of any test or monitoring data. This is because the method selected, and the heat exchanger's operating margin, are likely to have a significant effect on the required accuracy of the instrumentation, which may require upgrading.

NOTE: If the same instruments are used and left installed in back-to-back tests (e.g., in pre- and postcleaning tests), then, since the repeatability of the instruments will be reflected in the data acquired in the sample (thus becoming part of the precision error) and since it is only the difference between tests being measured, the bias errors will cancel out and only the precision error needs to be considered. This will allow for the possibility of measuring changes in heat exchanger performance that are less than the bias error.

C-11.1.2 Precision Errors. The precision error for each measurement parameter may be determined as follows:

(a) Collect test data (a set of measurement parameters) consisting of a minimum of 31 data sets ($N \geq 31$).

CAUTION: If fewer than 31 data sets are collected ($N < 31$), the uncertainty analysis that follows will be invalid. More than 31 data sets should be used if greater precision is desired. Refer to the reference in subpara. 3.2(n) of this Part if other than 31 data sets are taken.

(b) Calculate the average value for the measurement parameter (average of N measurements).

(c) Calculate the standard deviation (also referred to as the precision index) for the measurement parameter using the "nonbiased" or "$N - 1$" method.

(d) Divide the precision index for the measurement parameter by the square root of the total number of data

sets (31 or greater) to get the precision index of the average value.

(e) Multiply the precision index for the average value by the Student's *t* test value of 2 to get the precision error for the measurement parameter at the 95% confidence level.

(f) Repeat the steps in subparas. (a) through (e) above for each measurement parameter.

C-11.1.3 Spatial Errors. If more than one sensor location is being used to measure the test parameter (at *L* locations), then a spatial error analysis must be performed in lieu of the bias and precision error analyses described above. The total spatial uncertainty will take the place of the measurement errors used in determining the resultant sensitivities (see para. C-11.2).

NOTE: If a measured parameter is likely to vary throughout the space that contains the process being measured (as does airflow due to the flow profile created in a duct), then multiple measurements at more than one sensor location (at *L* locations) must be taken and spatial errors must be taken into account.

The total spatial uncertainty consists of the following three parts:

(a) the true spatial variation

(b) the time-dependent variation

(c) the instrument variation attributable to the precision error of the individual sensors

The total spatial uncertainty is equal to the root of the sum of the squares of the other three terms. With this in mind, there are two cases for total spatial uncertainty that need to be considered.

C-11.1.3.1 The first case, which is the simpler of the two, assumes that the sensor bias corresponds to the instrument bias, that the precision index corresponds to the time variation, and that both are small compared to the spatial variation. If this is the case, then the total spatial uncertainty is approximately equal to the true spatial variation and can be determined as follows:

(a) Determine the average (of *N* readings) for each sensor location (there will be *L* averages).

(b) Determine the average (of *L* locations) using the averages calculated in subpara. (a) above; there will be one average.

(c) Determine the differences between the parameter average in subpara. (b) above and the average instrument readings in subpara. (a) above and square the differences (there will be *L* squared differences).

(d) Sum the square of the differences, divide the sum by the total number of sensors less one ($L - 1$), and then take the square root.

If the assumptions made for this case are not true, then the above analysis will overestimate the contribution of the spatial variations to the measurement uncertainty.

C-11.1.3.2 The second case to consider is when the instrument precision and/or the time variations are not small compared to the true spatial variation. In this case, the instrument variation and the time variation should be removed from the total spatial uncertainty, as appropriate. For the second case, the instrument variation can be approximated by dividing the given instrument bias by the Student's *t* distribution for infinite degrees of freedom.

The time variation can be determined as follows:

(a) Determine the pooled variation.

(1) Sum the squares of the difference between the overall average (of $N \times L$ readings) and the individual sensor reading for each sensor ($N \times L$ readings).

(2) Divide the value in subpara. (1) above by the product of the number of sensors (*L*) times the number of readings less one ($N - 1$) taken by an individual sensor.

(3) Take the square root of the value determined in subpara. (2) above.

(b) Divide the pooled variation by the square root of the sum of the number of readings for all sensors ($N \times L$ readings).

The true spatial variation may be calculated by the method presented in the first case. The total spatial uncertainty can then be calculated as first presented.

NOTE: Additional guidance on spatial errors is presented in the reference in subpara. 3.2(n) of this Part.

C-11.1.4 Temperatures. The smaller the temperature differences, the more accurate the temperature measurements will need to be. The following techniques should be used to minimize temperature measurement errors:

(a) Calibrate temperature sensors and data acquisition equipment as a single unit, in situ, to arrive at an actual rather than calculated total bias error. If this is not possible, calculate the total bias error using the guidance provided in the reference in subpara. 3.2(n) of this Part.

(b) If using digital data acquisition equipment, select a system with the smallest analog-to-digital conversion error (as this error becomes part of the total bias error).

(c) When measuring individual temperatures (e.g., used in calculating the *LMTD*), use precision *RTD*s and individual calibration curves applied to each *RTD*.

(d) When measuring only temperature differences (e.g., ΔTs), use two temperature sensors connected together so that they measure ΔT as a single measurement or use the same measuring device for each temperature measurement. This will cause most of the error terms to "wash out" when any two temperatures are subtracted to calculate a ΔT.

(e) When measuring only temperature differences (e.g., ΔTs), apply the bias error to the temperature differences using the ΔT methodology for nonindependent bias limits [see the reference in subpara. 3.2(o) of this Part].

(f) Calibrate all temperature sensors used as a group (i.e., in the same oil bath).

(g) Calibrate temperature sensors over a range no greater than that expected to occur during the test, at a minimum of three points to minimize bias interpolation errors.

(h) Perform pre- and post-test calibrations to determine the validity of drift values used in calculating the bias error.

(i) Use two (or more) temperature sensors (for *RTD*s, they must be four wire) to measure the same parameter and divide the bias error for one sensor by the square root of the number of sensors used. The sensors must be independent of each other [see the reference in subpara. 3.2(p) of this Part].

(j) Increase ΔTs by adjusting either of the flow rates prior to the test. However, as the ΔTs (and their accuracies) increase due to reduced flows, the accuracies of the flow measurements will correspondingly decrease. Also, reducing test flow rates to below the design accident flow rates will require extrapolation back to the original design accident conditions. In these cases, a compromise must be made between flow accuracies, temperature accuracies, and calculational complexities (see Nonmandatory Appendix B of this Part, sections B-1 and B-2).

(k) Increase ΔTs by maximizing the heat load supplied to the heat exchanger.

(l) Locate temperature sensors such that they are readily accessible to facilitate proper calibration and maintenance.

(m) Always use thermal grease in thermowells to reduce thermowell temperature gradients and temperature sensor response times.

(n) For inlet temperatures, locate the sensor as close to the inlet of the heat exchanger as possible.

(o) For outlet temperatures, locate the sensor downstream of the heat exchanger in such a way as to allow for thorough mixture of the outlet fluid. Temperature stratification in the outlet fluid is a common occurrence and can be avoided by proper placement of the temperature sensor (see Nonmandatory Appendix B of this Part, section B-3).

C-11.1.5 Water Flows. The following techniques should be used to minimize water flow measurement errors:

(a) Install calibrated stainless steel orifices (or comparable high-accuracy primary flow elements) and flowmetering runs to provide the required accuracy and sufficient run of smooth pipe.

(b) Account for any fouling layer on the pipe and/or primary flow element in the flow bias error calculation.

(c) Account for the primary flow element design (i.e., concentric/eccentric orifice plate, nozzle, or Venturi) in the flow bias error calculation.

(d) Install ultrasonic flowmeters, magnetic flowmeters, or annubars, but only after careful consideration of their specific application.

(e) If the heat transfer coefficient test method is chosen, it is also possible to extrapolate the least accurate flow from the most accurate flow by performing a heat balance on both sides of the heat exchanger.

(f) Increase flow rates prior to the test. However, as the flow rate accuracies increase due to increased flows, the accuracies of the ΔT measurements will correspondingly decrease. In these cases, a compromise must be made between flow and temperature accuracies (see Nonmandatory Appendix B of this Part, section B-1).

(g) Locate water flow primary elements inside any bypass loops that may exist around the heat exchanger. If this is not possible, any bypass valve leakage must be reduced to zero to eliminate any errors that might be caused by bypass valve leakages.

For additional information on water flow measurement, see the reference in subpara. 3.2(q) of this Part.

C-11.1.6 Airflows. Accurate airflow measurements are difficult to obtain due to their sensitivity to duct work configurations and the difficulty of instrument installation. The plant configuration should be examined to determine the ability to obtain accurate airflow measurements. The following techniques should be used to minimize airflow measurement errors:

(a) If the heat transfer coefficient test method is chosen, it is possible to extrapolate the less accurate flow (which may be the airflow) from the more accurate flow by performing a heat balance on both sides of the heat exchanger (refer to paras. 6.2.5 and 6.3.5 of this Part).

(b) Locate airflow sensors in straight, unobstructed sections of ductwork according to accepted industry standards [i.e., references in subparas. 3.2(r) through (u) of this Part].

C-11.1.7 Relative Humidity. Relative humidity can be a very sensitive parameter, especially when condensation is occurring. The following techniques should be used to minimize relative humidity measurement errors:

(a) Inlet relative humidity instruments should be located as close to the heat exchanger as possible.

(b) Outlet relative humidity instruments should be located downstream of the heat exchanger in a location that ensures adequate mixing.

C-11.1.8 Water Pressure Loss. The following techniques should be used to minimize water pressure loss measurement error:

(a) Locate pressure taps close to the heat exchanger to minimize pressure drop due to pipe friction losses.

(b) Locate pressure taps so as to avoid fouling (i.e., locate at top versus bottom of pipe).

(c) Blow down or rod out pressure taps prior to taking measurements to remove any corrosion and/or fouling material (full-ported root valves will help facilitate this).

(d) Use instrument snubbers to reduce instrument reading fluctuations.

C-11.2 Result Sensitivities

The result sensitivities can be determined as follows:

(a) Define the functional relationship between the measurement parameters and the test result. The test result must be calculated in one step. All equations used must first be rearranged so that there is either

(1) a single equation expressing the test result on one side and the measurement parameters on the other or

(2) simultaneously calculated equations (e.g., in a spreadsheet) such that the measurement error for a given measurement parameter is propagated through all linked components simultaneously

(b) Calculate the nominal result using the average value for each measurement parameter.

(c) Calculate the result sensitivities for each measurement parameter and in each direction (both plus and minus). This is done by calculating the test result using the average values for each measurement parameter plus (and minus) the measurement errors for each measurement parameter (one parameter at a time, and one direction at a time). This process is referred to as numerical perturbation.

Examining the result sensitivities for each measurement parameter is one of the best ways to determine which instruments are worth upgrading to a higher accuracy.

C-11.3 Total Uncertainty

The total uncertainty can be determined as follows:

(a) Take the largest absolute value of the result sensitivities for each measurement parameter (resulting from the numerical perturbation in para. C-11.2) and combine them using the square root sum of the squares method. This is the total uncertainty of the test result.

NOTE: The total uncertainty in the test result may be less than the total error of any one of the measurement parameters. This can occur if there are "linked errors" in the calculation or if the same measurement parameter is used more than once in the calculation. In such cases, some of these errors will cancel out, resulting in a lower total uncertainty in the test result.

(b) Apply the total uncertainty to the nominal result in the most conservative direction to arrive at a test result with 95% coverage. This is the value that should be compared to the acceptance criteria (per section 9 of this Part).

C-11.4 Calculated Parameters

All test condition calculations shall be performed using the most accurate measured parameters as the required parameters (see section 6 of this Part). The other parameters (calculated from the required parameters) shall be chosen as described below.

For example, since $Q_{p,t}$ must equal $Q_{c,t}$, any one of the six parameters (inlet temperature, outlet temperature, and flow rate for both the process and the cooling fluid sides of the heat exchanger) can be calculated from the other five measured parameters. If all six parameters can be measured and one parameter is known to result in a greater total uncertainty than the others, then that parameter should be calculated, rather than measured, to avoid compounding its error through the calculation.

(a) To minimize error propagation through the calculations that follow the calculation of heat duty, the total uncertainty should be calculated for both the measured and the calculated value of each of the six parameters. If any calculated parameter results in less total uncertainty than the corresponding measured parameter, then the calculated parameter that has the least contribution to total uncertainty should be used instead of the corresponding measured parameter. Refer to subpara. 3.2(n) of this Part for additional guidance concerning the weighting method.

(b) To provide a "consistency" check on the test data, this sixth parameter should also be measured. The measured value of the parameter should be compared to the calculated value of the parameter. If the calculated value does not agree with the measured value, refer to Nonmandatory Appendices A and B of this Part for potential causes.

Part 24 Reactor Coolant and Recirculation Pump Condition Monitoring

1 INTRODUCTION

There is a need for standardization of in situ monitoring of reactor coolant pumpsets and recirculation pumpsets for the detection of pump and driver degradation and for the detection or prediction of equipment faults prior to functional failure. The intent of this Part is to provide a standard method for monitoring these pumpsets with a primary focus on vibration, bearing temperature, and seal condition monitoring. Additional parameters and techniques are used as appropriate. The data obtained are intended for monitoring and diagnostic analysis.

1.1 Scope

This Part establishes the requirements for monitoring of the reactor coolant pumps in pressurized water reactors and recirculation pumps in boiling-water reactors. This Part establishes the monitoring methods, intervals, parameters to be measured and evaluated, and records requirements.

1.2 Approach

This Part provides the steps necessary to implement a monitoring program. The major steps necessary include

(a) identifying the potential pumpset faults that could be detected by monitoring and the symptoms that would be produced by these faults

(b) determining the analysis techniques that are appropriate to the faults that are being monitored

(c) establishing the monitoring program necessary to detect equipment deterioration or pumpset faults early enough to prevent functional failure of the pumpset

(d) applying the evaluation criteria for each pumpset

2 DEFINITIONS

0.3×: 0.3 times the machine running speed.

0.5×: 0.5 times the machine running speed.

1×: the machine running speed in cpm.

1× amplitude: vibration amplitude at running speed. (See also *harmonics*.)

1× vectors: the vector of vibration, amplitude, and phase, at the machine running speed.

2×: twice the machine running speed.

2× amplitude: vibration amplitude at twice running speed. (See also *harmonics*.)

2× vectors: the vector of vibration, amplitude, and phase, at twice the machine running speed.

acceleration: the time rate of change of velocity. The unit for vibration acceleration is G. 1.0 G = acceleration of Earth's gravity = 386.4 in./sec^2 = 32.17 ft/sec^2 = 9.81 m/s^2.

accelerometer: an inertial transducer that converts the acceleration of mechanical vibration into a proportional electric signal.

acceptance region: area around the 1× or 2× vibration vector wherein the amplitude and phase are considered normal.

accuracy: the closeness of agreement between a measured value and the true value.

alarm, level 1: called Alert in API 670.

alarm, level 2: called Danger in API 670.

aliasing: in measurements, false indication of frequency components caused by sampling a dynamic signal at too low of a sampling frequency.

amplitude: the magnitude of vibration. Displacement is measured in peak to peak. Velocity and acceleration are measured in zero to peak or RMS.

asynchronous sampling: sampling of a vibration signal at time intervals not related to shaft rotation.

axial position: the average position, or change in position, of a rotor in the axial direction with respect to some fixed reference.

balance: see *unbalance*.

balance resonance speed: a shaft rotational speed (or speed range) that is equal to a lateral natural frequency of the rotor system. [See also *critical speed(s)*.]

baseline data: reference data set acquired when a machine is in acceptable condition after installation or most recent overhaul that establishes a basis to which subsequent data may be compared.

bearing instability: vibration caused by interaction between the fluid in the bearing and the rotor.

Bod plot: a pair of graphs in Cartesian format displaying any vibration vector (phase lag angle and amplitude) as a function of shaft rotational speed. The y-axis of the top graph represents phase lag angle, while the y-axis of the bottom graph represents amplitude. The common x-axis represents shaft rotational speed. Sometimes called an "unbalance response plot."

cascade plot: a series of spectrum plots taken over a speed range, usually at set speed intervals plotted against the speed.

casing vibration: the absolute vibration of machine housing or structure, usually measured on the bearing housing.

channel/loop: consists of a transducer or sensor, signal conditioning, and the hardware required to display its output signal.

critical speed(s): often any shaft rotational speed that is associated with high vibration amplitudes. In general, the speed that corresponds to a rotor lateral mode resonance frequency excited by rotor unbalance, in which case it is more correctly called the "balance resonance speed."

diagnostics: methods used to identify sources of malfunctions from data gathered using monitoring and analytical equipment.

displacement: a vibration measurement that quantifies the amplitude in engineering units of mils (1 mil = 0.001 in.) or micrometers.

electrical runout: a source of error on the output signal from a noncontacting probe system resulting from nonuniform electrical conductivity properties of the observed material or from the presence of a local magnetic field at a point on the shaft surface.

filter: electronic circuitry designed to pass or reject a specific frequency band of a signal.

frequency: the repetition rate of a periodic vibration per unit of time. Vibration frequency is typically expressed in units of cycles per second (Hertz), cycles per minute, or orders of shaft rotational speed.

frequency component: the amplitude, frequency, and phase characteristics of a dynamic signal filtered to a single frequency.

G: a unit of acceleration. (See also *acceleration*.)

gap voltage: a DC voltage from a proximity transducer that quantifies the distance from the tip of the transducer to the observed shaft surface.

Hanning window: windows are weighting or resolution functions. A Hanning window provides an amplitude accuracy versus frequency resolution compromise for general purpose measurements for rotating equipment.

harmonics: the vibration content of a spectrum consisting of exact frequency integer multiples or submultiples of a fundamental frequency.

Hertz (Hz): unit of frequency measurement in cycles per second.

loose part: a metallic object that is disengaged and free to drift or constrained and can affect nearby components.

mechanical runout: a source of error in the output signal of a proximity probe system resulting from surface irregularities, out of round shafts, and such.

misalignment: the degree to which the axes of machine components are noncollinear, either in offset or angularity.

mode shape: the deflection shape of a pumpset and support structure due to an applied dynamic force at a natural frequency; also used for the deflection shape of a forced response.

natural frequency: the frequency of free vibration of a mechanical system at which a specific natural mode shape of the system elements assumes its maximum amplitude.

nonsynchronous: any component of a vibration signal that has a frequency not equal to an integer multiple of shaft rotational speed (1×).

N× amplitude: vibration amplitude at N times running speed, where N is an integer. (See also *harmonics*.)

oil whirl: see *bearing instability*.

orbit: the path of the shaft centerline motion at the probe location during rotation.

overall: a value representing the magnitude of vibration over a frequency range determined by the design of the instrument or as specified. Expressed as rms, zero-peak (0-P), and peak-to-peak (P-P).

phase angle: the timing relationship, in degrees, between two signals, such as a once per revolution reference probe and a vibration signal.

polar plot: a graphical format used to display vectors (amplitude and phase) on a polar coordinate system.

preload: a unidirectional, axial, or radial static load due to external or internal mechanisms. Also applied to the installation configuration of certain bearing types such as tilting pad bearings.

proximity probe: a noncontacting device that measures the displacement motion and position of a surface relative to the probe-mounting location. Typically, proximity probes used for rotating machinery measure shaft displacement motion and position relative to the machine bearing(s) or housing.

pumpset: consists of the motor, coupling, pump, bearings, and seals.

radial vibration: shaft or casing vibration that is measured in a direction perpendicular to the shaft axis, often called lateral vibration.

rub: potentially severe machine malfunction consisting of contact between the rotating and stationary parts of a machine.

shaft bow: a condition of deformation of a shaft that results in a curved shaft centerline.

spectrum averaging: the averaging of multiple spectra to reduce random nonrecurring frequency components.

spectrum plot: an *x-y* plot in which the *x*-axis represents vibration frequency and the *y*-axis represents amplitudes of vibration components.

speed: the frequency at which a shaft is rotating at a given moment, usually expressed in units of revolutions per minute (rpm) or revolutions per second (rps).

steady-state data: data acquired from a machine at constant shaft rotational speed and process conditions.

synchronous: the component of a vibration signal that has a frequency equal to an integer multiple of the shaft rotational speed (1×). (See also *time synchronous averaging*.)

synchronous sampling: sampling of a vibration waveform initiated by a shaft phase-reference transducer.

time synchronous averaging: the averaging of multiple synchronously sampled waveforms to reduce the nonrotational-related frequency components.

transducer: generally, any device that converts a physical phenomenon into an electrical signal proportional to the amplitude of the sensed parameter (e.g., an accelerometer generates an electrical signal proportional to the acceleration of the point at which it is mounted).

trend: any parameter whose magnitude is displayed as a function of time.

unbalance: a rotor condition where the mass centerline (principal axis of inertia) does not coincide with the geometric centerline, expressed in units of gram-inches, gram-centimeters, or ounce-inches.

unfiltered: data that is not filtered and represents the original transducer output signal.

vane passing frequency: a frequency equal to the number of vanes times shaft rotational speed.

vector: a quantity that has both magnitude and angular orientation. For a vibration vector, magnitude is expressed as amplitude (displacement, velocity, or acceleration) and direction as phase angle (degrees).

velocity: the time rate of change of displacement. Units for velocity are inches/second or millimeters/second.

waterfall plot: similar to cascade plot, except that the *z*-axis is usually time or another time-related function, such as load, instead of shaft rotational speed (rpm or rps).

waveform plot: a presentation of the waveform of a signal as a function of time. A vibration time waveform can be observed on an oscilloscope in the time domain.

3 REFERENCES

The following is a list of publications referenced in this Part.

API 670, Vibration, Axial Position, and Bearing Temperature Monitoring Systems, 3rd Edition, November 1993

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005 (www.api.org)

ASME OM-S/G-2003, Part 12, Loose Part Monitoring in Light-Water Reactor Power Plants

ASME OM-S/G-2003, Part 14, Vibration Monitoring of Rotating Equipment in Nuclear Power Plants

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ASTM D6224-98, In-service Monitoring of Lubrication Oil for Auxiliary Power Plant Equipment

ASTM E1934-99, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography

Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959

NEMA MG 1, Motors and Generators

Publisher: National Electrical Manufacturers Association (NEMA), 1300 North 17th Street, Rosslyn, VA 22209 (www.nema.org)

4 MACHINE FAULTS

4.1 Introduction

Tables 1 through 3 list some of the more common pumpset and seal faults, their typical symptoms, and the more common analysis techniques employed to detect faults. The tables are not intended to be diagnostic tables. Table 1 describes pumpset mechanical faults, Table 2 describes seal faults, and Table 3 describes electrical motor faults.

5 VIBRATION, AXIAL POSITION, AND BEARING TEMPERATURE MONITORING EQUIPMENT

5.1 General

5.1.1 Pumpsets monitored under this Standard shall have a permanently installed vibration, axial position, and bearing temperature monitoring system as specified in API 670 with the additions, deletions, and changes as specified below. Although API 670 was written for horizontal machines, the most significant change required for API 670 to apply to the pumpsets defined in this Standard are the location and orientation of the transducers. See paras. 5.3.2 and 5.3.3.

Table 1 Pumpset Mechanical Faults

Possible Faults	Typical Symptoms	Analysis Type
Excessive bearing preload	1× and occasionally 2× vectors, non-circular orbit, bearing temperature rise	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Hydraulic instability	Nonsynchronous, random vibration < 1× speed	Average spectra and trend
Bearing instability	Vibration at 0.3× to < 0.5× speed	Orbit, spectra, and trend
Rub (partial or full rotation)	Harmonics of running speed, truncated waveforms	Orbit, spectra, trend, waveform, and vector
Shaft bent/bowed	Vibration at 1× speed	Orbit, spectra, and vector
Cracked shaft	Changes in 1× and 2× amplitude and phase	Orbit, spectra, trend, and vector
Unbalance	1× vectors and a typically circular orbit	Orbit, trend, and vector
Worn/damaged bearings	1× amplitude or increase in harmonic amplitudes	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Looseness	1× vector increase, harmonics of running speed, truncated waveforms	Spectra, waveform, and trend
Coupling misalignment or damage (angular/parallel)	1× and occasionally 2× vectors, noncircular orbit, bearing temperature rise	Bearing temperature, orbit, spectra, and vectors

Table 2 Seal Faults

Possible Faults [Note (1)]	Typical Symptoms	Analysis Type
Seal	Excessive leakage	Trend and correlation of seal parameters, such as flow, temperature, and pressure
Chipped	Failure to stage	
Cracked seal faces	Increment in cavity temperature	
Pinched or cut elastomers	Increase or decrease of bleedoff flow	
Wear	Increase of bleedoff or leakage temperature	
Dirt accumulation		
Blocked controlled bleedoff	Unbalanced seal pressure and temperatures	
	Seal pressure oscillations (spikes)	
Support systems		
Pressure surges		
Reduced cooling and/or injection water flow		
Increased CCW temperature		

NOTE:
(1) Some seal faults, such as excessive age and heat checking, cannot be detected by a monitoring system.

Table 3 Electrical Motor Faults

Possible Faults	Typical Symptoms [Note (1)]	Analysis Type
Broken rotor bar	$Np*S$ sidebands around 1× vibration, $Np*S$ vibration $Np*S$ sidebands around line frequency current, motor speed decrease	Motor current spectra, vibration spectra, and waveform
Nonuniform air gaps	2× line frequency vibration; $Np*S$ sidebands around 1× vibration; $Np*S$ vibration $Np*S$ sidebands around line frequency current; unusual shaft position change on start; rotor bar, stator slot frequencies, and sidebands	Motor current spectra, shaft centerline position, vibration spectra, and waveform
Insulation breakdown	Electrical protection relays actuate breakers	Visual examination of protective relays

NOTE:
(1) Np = number of poles on motor; S = slip.

5.1.2 Proximity probes are the preferred method of monitoring. Accelerometers may be used in addition to the proximity probes.

5.1.3 Instrumentation shall be suitable for the expected radiation where the instrument is to be installed.

5.2 Monitoring System

5.2.1 Monitors shall be in a controlled, indoor environment, preferably near or in the control room and easily accessible by operations personnel, with an audible alarm in the control room and a visual display of the measured parameters. This display need not be dedicated and may be shared with other parameters, as through the process computer, etc. The readout ranges specified below may be changed to meet special requirements. Reference API 670, para. 3.5.2.

5.2.2 The following parameters shall activate an audible alarm in the control room and shall be displayed:
(a) overall vibration amplitude
(b) 1× and 2× vectors, amplitude and phase of vibration
(c) thrust position
(d) bearing temperature
(e) vibration monitor circuit fault as in API 670, para. 3.5.1.1(k)

5.2.3 The number of relays may be different from those specified in API 670, para. 3.4.2.1.

5.2.4 The physical length of the probe and integral cable shall be in accordance with API 670, para. 3.1.1.4, if practicable. Other lengths may be specified if required.

5.2.5 The physical length of the probe extension cable shall be in accordance with API 670, para. 3.1.2, if practicable. Other lengths may be specified if required.

5.2.6 Radial proximity vibration monitors' readout may be analog or digital. If analog, the readout range shall be from 0 mils to at least 20 mils (500 μm) peak-to-peak displacement, with 0.5 mil (15 μm) resolution. If digital, the readout range shall be at least 25 mils (600 μm) with at least 0.5 mil (15 μm) resolution. Reference API 670, para. 3.5.3.1. Other ranges can be used as necessary for machine-specific needs.

5.2.7 Axial position monitors' readout may be analog or digital. The readout range shall be from −40 mils to +40 mils (−1.0 mm to 1.0 mm) axial movement, with at least 2 mil (50 μm) resolution. For sensor locations other than as specified in para. 5.4.1, the range may need to be evaluated. Reference API 670, para. 3.5.5.1. Other ranges may be used.

5.2.8 Accelerometer monitors shall contain an integrator to convert the sensed acceleration to velocity. Monitors may be analog or digital. If analog, the readout range shall be from 0 in./sec to 1.0 in./sec (25 mm/s) peak. Reference API 670, paras. 3.5.4.1 and 3.5.4.2. Other ranges may be used.

5.2.9 Accelerometer monitors shall contain a high pass filter in accordance with API 670, para. 3.5.4.4. The filter shall be set to one-third of the minimum running speed.

5.2.10 Accelerometer monitors shall contain a low pass filter in accordance with API 670, para. 3.5.4.4. This filter shall be set to the higher of 1.5 times rotorbar pass frequency or 1.5 times stator slot passing frequency.

5.3 Radial Proximity Sensor Locations

5.3.1 Each journal bearing in the pumpset including the motor, thrust bearing assembly (if present), and the pump shall have two proximity probes (*X* and *Y*) installed in accordance with para. 5.3.3 or API 670, para. 4.1.1.

5.3.2 Each pair of *X* and *Y* probes shall be coplanar. All *X* probes shall have the same angular orientation. The *Y* probes shall be 90 deg ± 5 deg from the *X* probes in a counterclockwise direction as seen from the top of the motor looking down. If practicable, the *X* plane shall be in line with the discharge pipe. Reference API 670, para. 4.1.1.1.

5.3.3 The probes monitoring the pump shaft shall be located above the seal housing as close as practicable to the top of the seal. Reference API 670, para. 4.1.1.1.

5.3.4 Total error due to surface condition, both electrical and mechanical, at the measurement planes in the motor and thrust bearing assembly (if present), shall not exceed 0.5 mils (15 μm). Total error due to surface condition, both electrical and mechanical, at the pump measurement plane specified in para. 5.3.3 may have runout exceeding 0.5 mils (15 μm), but should not exceed 3.0 mils (75 μm). Any error due to surface condition greater than 0.5 mils (15 μm) shall be documented as an 8-point reading including the phase relative to the phase reference mark. Reference API 670, para. 4.1.1.2. This surface condition should not be confused with operational runout.

5.4 Axial Proximity Sensor Locations

Each thrust bearing (motor and pump if present) shall have at least one (two are preferred) axially oriented proximity probes in accordance with API 670, para. 4.1.2. For locations other than specified in API 670, para. 4.1.2, the ranges must be evaluated.

5.5 Phase-Reference Sensor Location

5.5.1 There shall be at least one phase-reference transducer observing the motor rotor for each pumpset in accordance with API 670, para. 4.1.3. This transducer shall be separate from any speed transducer(s) that observe a multitooth gear or are part of a shutdown system or a safety-related system. Reference API 670, para. 4.1.3.

5.5.2 In addition to API 670, para. 4.1.3.6, the marking groove shall provide a pulse width of at least 1% of the shaft rotation period. Reference API 670, para. 4.1.3.6.

5.6 Bearing Temperature Sensors

5.6.1 Bearing temperature sensors are not required on the pump journal bearing. Reference API 670, para. 4.1.5.1.

5.6.2 Radial bearing temperature sensor locations shall consider significant bearing loading. Reference API 670, paras. 4.1.5.1.1 through 4.1.5.1.9.

5.6.3 Both the active and inactive thrust bearings shall have bearing temperature sensors installed. Reference API 670, paras. 4.1.5.2.1 and 4.1.5.2.3.

5.7 Sensor Locations for Optional Accelerometers

5.7.1 The natural frequencies of the combined pumpset and support structures shall be determined by analysis or test or both. Note that this is not a rotor-critical speed analysis. The frequencies and mode shapes calculated or measured shall be used to determine the appropriate locations for the accelerometers, which shall be installed in accordance with API 670, para. 4.2.3.

5.7.2 Three accelerometers shall be mounted to the top of the motor. Two of the accelerometers shall be mounted in the same angular orientation as the *X* and *Y* proximity probes ±5 deg, and the third shall be caused by sampling a dynamic signal at too low a sampling frequency.

5.7.3 If the running speed of the pumpset is above the first natural frequency, or the mode shape is not a simple beam mode, then two accelerometers shall be mounted at each radial bearing except the pump journal bearing.

5.8 Other Specifications

5.8.1 Wiring and conduit are not required to be in conformance to NFPA 70 as specified in API 670, para. 3.6.1. Field-mounted equipment shall be installed in containment subject to containment spray events but not to weather. Drains in conduit low points are not required as specified in API 670, para. 3.6.2.1.

5.8.2 Field-installed instrumentation is not expected to be installed in hazardous locations; thus, the portions of API 670 that refer to requirements for hazardous locations do not apply (API 670, para. 3.8.1).

5.8.3 The system is not expected to be wired into an automatic shutdown system; thus, the provisions of API 670 that refer to automatic shutdown do not apply (API 670, paras. 3.5.1.4, 3.5.1.5, and 3.8.3).

5.8.4 Accelerometers shall be calibrated in accordance with API 670, Table 2B. The lowest calibration frequency shall be the lower of 10 Hz or one-third the running speed.

6 VIBRATION DATA ANALYSIS SYSTEM REQUIREMENTS

6.1 Introduction

The purpose of this paragraph is to present the requirements for a digital analysis system that shall be used to perform the pumpset vibration data analysis and display. The listed data acquisition capability, required to perform the necessary analysis, requires a computer-based digital analysis system. Some of the support functions (signal conditioning, filtering, etc.) can be done with analog equipment. However, digital equipment is required to perform the data sampling, storage, archiving, and analysis.

6.2 Data Acquisition for Dynamic Signals

6.2.1 Introduction. Data acquisition refers to the process of digitally sampling an analog dynamic signal.

The system needs to be able to support data acquisition for each of the data collection modes described in section 8. The following data acquisition specifications provide suitable data for the analysis functions listed in para. 6.4.

6.2.2 General Requirements

(a) over-range detection/indication
(b) A/D conversion as required to meet the accuracy requirements of para. 6.3
(c) dynamic range 78 dB or better
(d) magnitude accuracy 5% of full-scale range

6.2.3 Spectra Sampling Requirements

(a) 400 line minimum resolution
(b) frequency range
(1) proximity probe at least 20 times full speed of pump
(2) accelerometers at least 10 kHz
(c) Hanning window
(d) anti-aliasing filters
(e) four averages (minimum)
(f) 50% overlap
(g) sample rate 2.56 times frequency range
(h) asynchronous sampling

6.2.4 Waveform Sampling Requirements

(a) at least 100 sample points per revolution at full speed
(b) at least a 10 revolution sample length
(c) no anti-aliasing filters
(d) X and Y probes simultaneously sampled with phase reference
(e) time synchronous averaged waveforms with at least 16 averages

6.3 System Accuracy and Calibration

6.3.1 The channel or loop accuracy including the computer system shall be within 10% for radial shaft vibration, thrust position, and bearing temperature.

6.3.2 The channel or loop accuracy including the computer system for casing vibration shall be within 10% over a range from 0.1 G to 75 G at a single reference frequency. The channel accuracy shall be within 20% over the frequency range, as specified in paras. 5.2.9 and 5.2.10.

6.3.3 The channel or loop accuracy may be calculated using the square-root-of-the-sum-of-squares (SRSS) combination of the individual accuracies of the sensor, the monitor, and the computer system.

6.4 Data Analysis and Display

The analysis and display functions listed in the following paragraphs shall be provided.

6.4.1 General Requirements

(a) cursor readout ability for all plots
(b) manual and auto scaling for all plots

6.4.2 Amplitude and Phase Requirements

(a) Overall amplitudes shall be measured and expressed as acceleration, velocity, or displacement.

(b) In addition to the alarms specified in the API 670 monitoring system, the analysis system shall provide 1× and 2× acceptance region alarms for radial proximity probe channels.

6.4.3 Frequency Domain Analysis

(a) frequency spectra, in which linear amplitudes, accelerations, velocities, or displacements are plotted versus linear frequency expressed as cycles per second, (Hz), cycles per minute (cpm), or orders, synchronized to a phase reference
(b) waterfall plots with at least 50 spectra plotted versus time
(c) cascade plots with at least 50 spectra plotted versus speed

6.4.4 Time Waveform Analysis

(a) time waveform plots of unfiltered data
(b) time waveform plots of time synchronous averaged data
(c) orbit plots of unfiltered data
(d) orbit plots of synchronous (1×) or running speed data
(e) time synchronous averaged orbit plots

6.4.5 Balance/Critical Speed Analysis

(a) Bodé plot for speed-transient data
(b) polar plots for speed-transient data
(c) vector plots for monitoring balance response changes
(d) shaft centerline plots; polar plot of shaft centerline position within bearing
(e) gap voltage plots

6.4.6 Trend Analysis. Trend analysis refers to any measured parameter as a function of time in a Cartesian plot.

6.5 Data Storage

6.5.1 The system shall provide storage and display of either averaged or maximum/minimum data stored at least once per hour or at an interval specified when purchasing the system. Data shall be stored for at least 24 mo. The minimum vibration-related data to be stored shall be the overall amplitude, running speed amplitude and phase, twice-running speed amplitude and phase, gap voltage, and speed. The minimum nonvibration-related data to be stored shall be the bearing temperatures, seal parameters per section 7, pumpset discharge temperature, pumpset pressure, pumpset flow rate, reactor power level, and other parameters as applicable.

Averaged data shall be computed as the average of at least 10 points collected over the interval. Maximum/minimum data shall similarly apply to at least ten data points.

6.5.2 The system shall provide storage of the following data at a minimal interval of at least once per day:
(a) time waveforms with phase reference
(b) time synchronous waveforms
(c) averaged spectra (eight averages)

6.5.3 The system shall collect and store the data as specified in paras. 6.5.1 and 6.5.2 on an alarm.

6.5.4 The system shall collect and store the vibration-related data as specified in paras. 6.5.1 and 6.5.2 on coastdown and startup at a rate of at least every 50 rpm. Additionally, one set of data, as specified in para. 6.5.2, shall be obtained once the pumpset has reached operating speed.

6.5.5 The system shall provide the capability to change the interval for the data collected in paras. 6.5.1 and 6.5.2 for startup or troubled machine monitoring. The minimum recommended intervals available shall be at least every 2 min for data in para. 6.5.1 and every 1 hr for data in para. 6.5.2.

6.6 Continuous Display of Dynamic Signals

6.6.1 The system shall be capable of displaying any of the plots specified in para. 6.4 except Cascade and Bod with an automatic refresh rate of at least once per 10 sec.

6.6.2 The system shall be capable of printing the display on demand or saving the display data to disk.

7 SEAL MONITORING

7.1 Introduction

7.1.1 Seals monitored under this Standard shall have permanently installed sensors that monitor the parameters as specified below.

7.1.2 Instrumentation shall be suitable for the expected radiation where the instrument is to be installed.

7.1.3 Vibration limits and shaft displacement limits for the pumpset are generally less than that for the seal. Axial displacement for the seal is limited by the spring gap, usually much greater than the 0.060 in. to 0.120 in. (1.5 mm to 3 mm) total axial displacement of the pump shaft. Seal problems will not show up as a vibration indication.

7.2 Monitoring System

7.2.1 Monitors shall be in a controlled, indoor environment, preferably near or in the control room and easily accessible by operations personnel, with an audible alarm in the control room and a visible display of the measured parameters. This display need not be dedicated and may be shared with other parameters, as through the process computer, etc. The readout ranges specified below may be changed to meet special requirements.

7.2.2 The applicable parameters in para. 7.2.4 or 7.2.5 shall activate the audible alarm in the control room and shall be displayed.

7.2.3 The channel or loop accuracy, including the computer system, shall be within 5% for temperature, pressure, and flow.

7.2.4 Hydrostatic Seals. The following parameters when possible shall be recorded at least once per hour:
(a) injection flow
(b) injection temperature
(c) injection pressure
(d) cooling water flow
(e) cooling water temperature
(f) cooling water pressure
(g) bearing water temperature
(h) number 3 seal injection flow to seal
(i) number 3 seal injection temperature
(j) number 3 seal injection pressure

7.2.5 Staged Seals. The following seal parameters when possible shall be recorded at least once per hour:
(a) seal staging pressures
(b) controlled bleedoff flow rate
(c) measured seal leakage rate
(d) controlled bleedoff temperature
(e) lower seal temperature
(f) seal injection temperature
(g) seal injection flow rate
(h) CCW temperature

7.2.6 Also, the following system parameters shall be recorded at the time seal data is collected:
(a) power level
(b) system temperature
(c) system pressure
(d) pump flow
(e) pump speed
(f) pump ΔP

7.2.7 Computer systems shall store data for at least 24 months.

7.3 Monitoring and Analysis Requirements

7.3.1 Introduction. The effective use of the installed monitoring system is crucial to an effective monitoring program. Alarms must be set properly, periodic review of the data must be done, and an effective plan for responding to an alarm must be in place.

7.3.2 Startup Monitoring. Review of the trend of the seal parameters shall be performed at least once per hour during system pressurization.

7.3.3 Periodic Monitoring

(a) The intent of periodic monitoring is as follows:

(1) Provide a separate monitoring system and method to ensure that problems with the seal are not missed because of deficiencies in the installed monitoring system.

(2) Provide long-term trend data offline from the monitoring system.

(3) Ensure that a qualified person periodically reviews the seal condition.

(b) Periodic monitoring is required at least every 2 weeks. If any seal parameters are unusual, over the alarm value, or a significant trend is seen, perform an evaluation in accordance with para. 7.4, and perform monitoring in accordance with para. 7.5 as required.

(c) A long-term trending database shall be maintained separately from the installed monitoring system. This archive shall be easily available as required to monitor for long-term changes in seal condition, provide an archive of past seal problems, and provide for statistical and other specialized analysis.

(d) At an interval to ensure no data loss and the usefulness of the long-term trending database, transfer the historical files from the monitoring system to the long-term trending and archiving database.

7.3.4 Shutdown Monitoring. Engineering shall review the trend of the seal parameters at least once per hour during system depressurization.

7.4 Seal Alarm Response

7.4.1 When the installed monitoring system alarms, the first response is usually by the Operators. The initial actions to be taken shall include the following:

(a) false alarm discrimination (i.e., does the alarm clear and was the event related to a plant event such as a pumpset start?)

(b) severity evaluation

(c) determination if pumpset shall be shut down immediately

(d) notification of engineering for further evaluation

7.4.2 When notified of an alarm, engineering shall make a further evaluation of the condition of the pumpset. This evaluation shall include the following:

(a) correlation of seal data to other plant data

(b) comparison of seal data to other seals and historical data

(c) false alarm discrimination

(d) review of relevant data collected by the monitoring system

(e) evaluation of the seal condition per manufacturer guidelines

Table 4 Minimum Monitoring and Recording Intervals

Run Time	Monitoring Interval
Initial 2 min	Continuous
Initial 20 min	2 min
< 24 hr	One reading within the first 24 hr
24–72 hr	24 hr
3–7 days	48 hr
7–15 days [Note (1)]	1 week

NOTE:
(1) Monitoring shall be continued until at least a week after the plant is stable.

(f) determination to implement an enhanced monitoring program in accordance with para. 7.5

7.5 Enhanced Monitoring of a Troubled Seal

If an unusual seal condition is detected, an enhanced monitoring program shall be implemented until the problem is corrected or the pumpset is shut down. The interval of the monitoring shall be based on the trend and the result of the analysis and interpretation.

8 VIBRATION, AXIAL POSITION, AND BEARING TEMPERATURE MONITORING

8.1 Introduction

The effective use of the installed monitoring system is crucial to an effective monitoring program. Alarms must be set properly, periodic review of the data must be performed, and an effective plan for responding to an alarm must be in place.

8.2 Postmaintenance Monitoring

After every pumpset maintenance, the monitoring specified below shall be performed to verify the condition of the pumpset and to establish new baseline data.

8.2.1 Start-Up Monitoring Schedule. Perform monitoring per the schedule provided in Table 4.

8.2.2 Pumpset Start-Up Monitoring Procedure

(a) The loose parts monitoring system, if available, shall be monitored via the speaker or headphones. Select the appropriate sensor to detect a loose part coming from the pump.

(b) Evaluate any loose parts alarms during the run for possible pump-related loose part events.

(c) Monitor the spectra and the orbit.

(d) Monitor the overall vibration using the installed vibration displays.

(e) Take one set of periodic monitoring data per para. 8.3.

(f) If available, set up to record the first 20 min on either tape or a transient data acquisition system. If any unusual vibrations were seen during the run, the data shall be analyzed for the cause of the vibration.

(g) Inspect the orbit and spectra of the *X* and *Y* probes for significant changes.

(h) Monitor the 1× amplitude and phase.

(i) Examine the 1× and 2× vector trends and polar plots of all probes for any unusual changes. For example, the following may indicate an unusual change:

(1) an amplitude increasing at a rate of 1 mil (25 μm) in 5 min

(2) an amplitude increase or decrease of 1 mil (25 μm)

(3) an increase in 2× amplitude of 50% when above 0.5 mils (15 μm)

(4) an increase in 2× amplitude of 1 mil (25 μm)

(5) a change in the phase of the 1× or 2× of 30 deg

(j) If vibration, thrust position, or bearing temperature are unusual, over the alarm value, or a significant trend is seen, perform an evaluation in accordance with para. 8.6 and perform monitoring in accordance with para. 8.7 as required.

(k) Whenever any spectrum or orbit shows a significant change, make a long-term storage media copy of the filtered and unfiltered orbit, time synchronous average orbit, and the spectra.

(l) Make long-term storage media copies of the data listed below from the installed computer system. Data shall cover the period from before startup to establishment of baseline. Long-term storage media may be paper copies, disk files (floppy, hard drive, optical, etc.), or other retrievable records.

(1) overall vibration amplitude trend plots

(2) thrust position trend plots

(3) bearing temperature trend plot

(4) 1× amplitude and phase trend plots

(5) 1× acceptance region plots

(6) 2× amplitude and phase trend plots

(7) 2× acceptance region plots

(8) waterfall plots as a function of delta time

(9) gap voltage trend plots

(m) After at least 7 days of stable operation, take baseline data per para. 8.3.

8.3 Baseline

8.3.1 A new baseline shall be established for the pumpset after every outage where maintenance work is performed on the pumpsets.

8.3.2 At least 7 days (preferably 15 days) of vibration data at stable operation shall be available before acquiring new baseline data.

8.3.3 The condition of the pumpsets shall be evaluated to be acceptable before accepting the baseline data.

8.3.4 The following baseline data shall be stored for each pumpset:

(a) unfiltered orbit and waveform

(b) spectra

(c) filtered orbit and waveform

(d) time synchronous orbits and waveform

(e) acceptance region plot of the 1× rpm (rps) and 2× rpm (rps) component for each sensor

(f) process data at time of acquiring new baseline data

(g) analog monitor front panel readings

(h) current value displays from computer system of overall amplitude and gap voltage as applicable for each sensor

(i) current alarm settings

8.3.5 The baseline data shall be maintained for the life of the pumpset.

8.4 Periodic Monitoring

8.4.1 The intent of periodic monitoring is as follows:

(a) Provide a separate monitoring system and method to ensure that problems with the pumpset are not missed because of deficiencies in the installed monitoring system.

(b) Provide long-term trend data offline from the monitoring system.

(c) Ensure that a qualified person periodically reviews the pumpset condition.

8.4.2 Periodic monitoring is required at least every 2 weeks. If vibration, thrust position, or bearing temperature are unusual, over the alarm value, or a significant trend is seen, perform an evaluation in accordance with para. 8.6 and perform monitoring in accordance with para. 8.7 as required. As a minimum, the following data shall be reviewed:

(a) current alarms

(b) alarms received since last review

(c) trend of gap voltage; note any changes over 2 V

(d) trend of the overall amplitude for each vibration sensor

(e) trend of the 1× and 2× amplitude and phase for each vibration sensor

(f) trend of the bearing temperatures

8.4.3 A monthly 10-min analog or digital tape recording of each vibration channel is recommended.

8.4.4 A long-term trending database shall be maintained separately from the installed monitoring system. This archive shall be easily available as required to monitor for long-term changes in pumpset condition, to provide an archive of past pumpset problems, and to provide for statistical and other specialized analysis.

8.4.5 At an interval to ensure no data loss and the usefulness of the long-term trending database, transfer the historical files from the monitoring system to the long-term trending and archiving database.

8.4.6 Record the following process data within 1 hr (at steady-state conditions if possible) of the collection of the pumpset condition data:

(a) date/time of monitoring

(b) number of pumpset alarms in period
(c) number of system events in period
(d) power level
(e) system temperature
(f) system pressure
(g) days online
(h) pumpset flow if flow may vary
(i) pumpset speed if speed may vary

8.4.7 If the station has a computerized vibration monitoring program using portable data collectors, data from each channel shall be taken with that system for long-term trending and offline analysis.

8.4.8 Obtain a long-term storage media copy of the alarm list since the last time this procedure was performed.

8.5 Preoutage Coastdown

8.5.1 Before each outage during the normal pumpset coastdown, record the data as specified in para. 6.5.4.

8.5.2 Examine data for any unusual patterns.

8.5.3 Determine coastdown time and compare to normal.

8.5.4 Note orbit shape during coastdown for any unusual patterns.

8.6 Vibration Alarm Response

8.6.1 When the installed monitoring system alarms, the first response is usually by the Operators. The initial actions to be taken shall include the following:
(a) false alarm discrimination (i.e., does the alarm clear, is the circuit fault indication on, and was the event related to a plant event such as a pumpset start?)
(b) severity evaluation
(c) determination if pumpset shall be shut down immediately
(d) notification of engineering for further evaluation

8.6.2 When notified of an alarm, engineering shall make a further evaluation of the condition of the pumpset. This evaluation shall include the following:
(a) correlation of pumpset data to other plant data
(b) false alarm discrimination
(c) review of relevant data collected by the monitoring system
(d) check of the loose parts system for any corresponding events
(e) evaluation of the pumpset condition in accordance with section 10; Part 14 may be used as a guide in this evaluation
(f) determination if an enhanced monitoring program in accordance with para. 8.7 should be implemented
(g) determination if alarm values should be changed per section 9

8.7 Enhanced Monitoring of a Troubled Pumpset

If unusual vibration or a trend in vibration, thrust position, or bearing temperature is detected, an enhanced monitoring program shall be implemented until the problem is corrected or the pumpset is shut down. The enhanced monitoring program shall include, as applicable, additional instrumentation (tape recorders, oscilloscopes, spectrum analyzers, etc.) and continuous or intermittent attendance by qualified analysis personnel. The interval of the monitoring and data storage shall be based on the severity, rate of change, and the result of the analysis and diagnostics as specified in section 10. Part 14 may be used as a guide in developing an enhanced monitoring program.

9 ALARM SETTINGS

9.1 Determining Alarm Points for Overall Vibration Amplitude

9.1.1 The alarm values for vibration amplitude shall be based on the baseline values as recorded in para. 8.3.

9.1.2 The Level 1 alarm points for the shaft vibration shall be 1.5 times the baseline value but not exceeding the manufacturer's recommended alarm value.

9.1.3 The Level 2 alarm point for the shaft vibration shall be 2.0 times the baseline value but not exceeding the manufacturer's recommended shutdown value.

9.1.4 The Level 1 alarm point for the casing velocity shall be calculated as 1.5 times the baseline value but not less than 0.1 IPS (2.5 mm/s). The alarm shall not exceed the manufacturer's recommended alert value or 0.3 IPS (7.5 mm/s) without review and justification.

9.1.5 The Level 2 alarm point for the casing velocity shall be calculated as 2.0 times the baseline value but not less than 0.2 in./sec (5 mm/s). The alarm shall not exceed the manufacturer's recommended shutdown value or 0.6 in./sec (15 mm/s) without review and justification.

9.1.6 The alarm points may be rounded down to the nearest meter division for ease in setting.

9.2 Determining 1× and 2× Vector Acceptance Regions

9.2.1 The alarm values for vector acceptance regions shall be based on recent data collected before the baseline point as recorded in para. 8.3. At least 20 days of data is preferred. Because the vector data tends to be noisier than the overall amplitude data, a sample of data over several days is required.

9.2.2 The phase angle range of the sample of data or the calculated acceptance region may cross the

360–0 deg line. Provisions for correctly calculating and specifying the acceptance region in this case must be implemented in the plant procedures.

9.2.3 The maximum and minimum values from the sample data shall be used for the calculations below.

9.2.4 Acceptance regions shall be developed from the maximum and minimum values.

$$\text{Accept} = \left(\frac{\text{max.} + \text{min.}}{2}\right) \pm 1.5(\text{max.} - \text{min.})$$

9.2.5 Round the angle to a multiple of 15 deg. Round down for minimum and up for maximum. If the phase is undefined for any of the sample data, set the angles to 0 deg and 360 deg.

9.2.6 If less than 10 days of data were used, the phase acceptance range may be increased by subtracting 15 from the minimum phase and adding 15 to the maximum phase.

9.2.7 Round the amplitude acceptance limits down and up to the nearest 0.1 mil (2.5 μm).

9.3 Determining Alarm Points for Thrust Position

9.3.1 Thrust position alarms shall be based on the thrust bearing clearance. The preferred method is to record the change in position as the rotor goes from down thrust to up thrust. Installed measured clearance may be used if the clearance as measured by the thrust probe is not available.

9.3.2 Zero thrust as indicated on the monitor is defined as the axial position of the rotor when the rotor is at normal and stable conditions. This reading is taken during baseline measurements as described in para. 8.3.

9.3.3 The monitor shall be set so that upward movement of the indication corresponds to upthrust of the rotor. Reference API 670, para. 3.5.5.5.

9.3.4 The four alarms are set based on change from the initial thrust clearances. Level 1 alarm is when the normal thrust clearance has increased by more than 10 mils (250 μm) in one direction. Level 2 alarm is when the thrust clearance has increased by more than 15 mils (375 μm) in one direction. Table 5 shows an example for a pump with normal upthrust.

9.4 Determining Alarm Points for Bearing Temperature

9.4.1 Bearing temperatures shall be set in accordance with the manufacturer's recommendation. Industry practices or plant experiences may also be considered in determining alarm points.

Table 5 Typical Thrust Position Alarm Setpoints for a Pump With Normal Upthrust

Alarm Level	Thrust Position
Level 2 alarm, up	Zero + 15 mils (375 μm)
Level 1 alarm, up	Zero + 10 mils (250 μm)
Zero	Thrust runner against the upper thrust pads
Level 1 alarm, down	Zero − the thrust clearance − 10 mils (250 μm)
Level 2 alarm, down	Zero − the thrust clearance − 15 mils (375 μm)

9.5 Alarm Settings

9.5.1 Alarm settings may be changed if the operation of the pumpset has caused a change in the parameter and the change has been evaluated and deemed acceptable.

10 ANALYSIS AND DIAGNOSTICS

10.1 Introduction

The accurate diagnosis of equipment condition is essential to maintaining operability, reducing plant down time, and increasing productivity. Diagnostics based on the analysis and interpretation of vibration data in conjunction with other equipment parameters such as flow, temperature, and pressure indicate the earliest signs of equipment degradation. Analysis and interpretation of vibration data shall be performed by someone experienced in vibration analysis techniques.

The intent of this Part is to list the types of data and the methodology used to diagnose equipment condition. This Part is not intended to take the place of established plant procedures or to delineate certain analysis methods, but rather to provide guidance where plant procedures do not exist or could be improved.

10.2 Data Types

Data collected for analysis shall include the following:

(a) routine steady-state data (para. 8.4)

(b) data collected based on an alarm condition (para. 8.6)

(c) data collected during transient conditions (paras. 8.2 and 8.5)

10.3 Analysis Methods

The data collected per para. 10.2 shall be analyzed using the following methods:

(a) overall vibration (amplitude trends)

(b) vibration orbit (form, precession, magnitude, and trends)

(c) vibration spectra (harmonic content, amplitude, trends, and phase)

(d) acceptance region deviations

(e) 1× and 2× vector analysis
(f) shaft position trends
(g) process data (deviations from normal values versus plant conditions and trends)
(h) machine geometry
(i) maintenance history
(j) history of similar events on similar machines

10.4 Data Analysis

An analysis is the process of reviewing data collected as specified by this standard on a machine to determine equipment condition and diagnose equipment problems. A typical analysis would include the following:

(a) comparing current vibration, process, and equipment parameters to baseline and determining any differences
(b) determining if any trends are present or are developing
(c) reviewing equipment history for similar occurrences
(d) reviewing the equipment history of like machines for similar occurrences
(e) determining significant symptoms (section 4)
(f) determining probable causes of the symptoms (section 4, i.e., determining possible equipment faults, process changes, or plant conditions that could produce the observed responses)
(g) evaluating the probable condition of the pumpset and assessing the severity

11 ADDITIONAL TECHNOLOGIES

The technologies described here shall be used in conjunction with vibration analysis to determine the condition of pumpsets. While one technology alone may convey some evidence of a malfunction condition, the inter-relationships between all of these technologies provides for a more complete and accurate diagnosis of the condition of the pumpset.

11.1 Thermography

11.1.1 Thermography shall be used at least before and after each refueling outage, to monitor switchgear, breakers, and control relays providing electrical power to the pumpset in accordance with ASTM E1934-99, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography, para. 3.5.

11.1.2 See Nonmandatory Appendix B of this Part for additional information.

11.2 Lube Oil Analysis

11.2.1 Pumpset lubricating oil shall be monitored for wear debris, lubricant cleanliness (foreign material such as water and particulates), and oil chemistry in accordance with the applicable sections of ASTM D6224, Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment.

11.2.2 New oil shall be sampled and tested in accordance with the recommended tests given in ASTM D6224, Table 1, Turbine Type Oils, before being put into the pumpset bearings.

11.2.3 Used oils shall be sampled at each refueling outage, in accordance with ASTM D6224, preferably while running or at least within 25 min of being tripped.

11.2.4 Used oils shall be tested in accordance with the recommended test methods given in ASTM D6224, Table 2, Turbine Type Oils (if other types of oil are in service, see ASTM D6224). Used oil that is to be left in service shall also have an oxidation stability test as specified in ASTM D6224, Table 2, Turbine Type Oils.

11.2.5 See Nonmandatory Appendix C of this Part for additional information.

11.3 Motor Current Signature Analysis

11.3.1 Motor current signature analysis shall include the measurement of the Np × slip frequency sidebands of the line frequency component and the rotor bar and stator slot passing frequencies.

11.3.2 Motor current signature analysis shall be performed prior to each refueling outage and after every outage where maintenance work is performed on the pumpset.

11.3.3 See Nonmandatory Appendix D of this Part for additional information.

11.4 Motor Electrical Monitoring and Testing

11.4.1 The motor electrical operating parameters (current, voltage, winding temperatures, etc.) shall be monitored in accordance with the manufacturer's recommendations, industry standards and practice, and plant experience. The following parameters, as applicable, shall activate an audible alarm in the control room and shall be displayed:

(a) current
(b) phase balance
(c) winding temperature
(d) cooling water flow rate
(e) oil level
(f) winding cooler leakage

11.4.2 The motor shall be tested in accordance with the applicable parts of NEMA MG 1 Motors and Generators, para. 3.6.

11.5 Loose Parts Monitoring

11.5.1 The loose parts monitoring system shall be installed and operated in accordance with ASME OM Part 12, Loose Part Monitoring in Light-Water Reactor Power Plants, para. 3.1.

11.5.2 The loose parts monitoring system shall be checked for corresponding alarms whenever a pumpset alarm is received.

11.5.3 The loose parts monitoring system channel, which is closest to the pumpset downstream impact location, shall be monitored when starting a pumpset after maintenance.

11.5.4 See Nonmandatory Appendix E of this Part for additional information.

12 OTHER

12.1 Calibrations

Calibrations shall be performed per the manufacturer's recommendations and the plant maintenance program. Consideration of the performance of the sensor (e.g., bias current and trend of 60 Hz frequency component) may be used in determining calibration requirements.

12.2 Quality

The instrumentation, computer systems, documentation, and data described in this standard are considered nonnuclear safety as described in the plant's QA plan. Normal industry good practices shall be followed in calibration, controlling, backing up, and storing documentation and data.

Part 24, Nonmandatory Appendix A
References

Below is a list of useful documents.

ISO 2372, Mechanical vibration of machines with operating speeds from 10 to 200 rev/s — Basis for specifying evaluation standards

ISO 2373, Mechanical vibration of certain rotating electrical machinery with shaft heights between 80 and 400 mm — Measurement and evaluation of the vibration severity

ISO 2954, Mechanical vibration of rotating and reciprocating machinery — Requirements for instruments for measuring vibration severity

ISO 3945, Mechanical vibration of large rotating machines with speed range from 10 to 200 r/s — Measurement and evaluation of vibration severity in situ

ISO 7919-1, Mechanical vibration of non-reciprocating machines — Measurements on rotating shafts and evaluation — Part 1: General guidelines

ISO 10816, Mechanical vibration — Evaluation of machine vibration by measurements of non-rotating parts

Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

Part 24, Nonmandatory Appendix B
Thermography

Thermography is the use of noncontact infrared technology to measure the surface temperature of equipment and can be used to detect faults in machinery, which create localized temperature changes. Thermography as a trend tool can be used for the early detection of developing equipment problems and identification of possible problem areas once a fault has developed.

(a) In electrical systems, such faults include the following:

(1) loose or corroded connections
(2) overloads
(3) phase imbalance
(4) short circuits
(5) mismatched or misinstalled components

Electrical system exceptions can be detected and identified using absolute temperature criteria published in ANSI, IEEE, and NEMA published standards.

(b) In mechanical systems, typical faults include the following:

(1) improper lubrication
(2) misalignment
(3) worn components
(4) improper loading

Part 24, Nonmandatory Appendix C
Lube Oil Analysis

Monitoring of lubricating oil in a pumpset can help to minimize the high cost of oil changes and unplanned shutdowns. The cost of changing the oil in the pumpsets covered by this Standard may be significantly higher than for other applications, because the oil may be slightly radioactive. An effective lubricating oil monitoring program, in accordance with ASTM D6224, Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment, may be used to perform oil changes based on test results rather than on the basis of service time or calendar time. Such a program is also intended to guard against excessive component wear, oil degradation, or contamination, thereby minimizing the potential of catastrophic machine problems that are more likely to occur in the absence of such a monitoring program.

The analysis tests specified are for oils that are considered turbine type. This type of oil is commonly used in pumps and motors. Service oils that are not turbine type shall have tests performed, as specified in ASTM D6224, that are appropriate for their oil type. PAO synthetic oils, if used, shall be tested with the same test methods specified for turbine-type oils; however, the oxidation stability test results may require vendor interpretation.

New oil shall be prefiltered in accordance with para. 7.3 of ASTM D6224.

Part 24, Nonmandatory Appendix D
Motor Current Signature Analysis

Motor current analysis is a monitoring tool for induction motor-driven equipment that gives information to diagnose electrical and mechanical conditions of the rotor. It is an in-service analysis of the frequency spectrum of the motor current made with the motor operating at normal load without interfering with the function of the driven machine or process.

Voltage signals from a current transformer shunt in one phase of the power supply are analyzed using a frequency spectrum. Rotor winding analysis is done by comparing the amplitudes of the sideband components with the amplitude of the line frequency component. The sideband amplitudes become larger as damage to the rotor progresses. The amplitude and frequency of the sidebands are used to assess the number and severity of broken rotor bars.

Levels of static and dynamic eccentricity of the rotor within the stator are determined from the rotor bar passing frequency and the running speed sideband amplitudes in the motor current signal. Data must be compensated for machine load and process parameter changes. With experience, an accurate determination of the condition of the rotor can be determined.

(a) Motor current analysis is probably the most effective on-line tool for detecting the following:

(1) cracked or broken rotor bars
(2) cracked motor end rings
(3) high resistance joints
(4) casting porosities or blow holes in aluminum die-cast rotors
(5) poor joint brazing in fabricated rotors
(6) rotor winding problems in slip-ring induction motors

(b) Motor current analysis can also detect many of the motor mechanical problems such as the following:

(1) stationary or rotating air gap irregularities
(2) unbalanced magnetic pull
(3) mechanical unbalance
(4) bent shaft, thermal bow
(5) out-of-round stator or bearings

It is not the best detector of many of the above mechanical problems, but it provides support for motor vibration analysis.

Part 24, Nonmandatory Appendix E
Loose Parts Monitoring

Data from the loose parts monitoring system is helpful for diagnosing the following conditions:

(a) missing parts of an impeller

(b) damage from a loose part going through a pumpset

(c) pumpset internal loose parts or severe mechanical looseness

(d) pumpset rubbing

(e) pumpset cavitation

(f) a pumpset vibration alarm caused by thermal expansion during heat-up or cool-down

(g) pumpset flow–induced vibration

Part 25
Performance Testing of Emergency Core Cooling Systems in Light-Water Reactor Power Plants

Superseded by Part 28.

Part 26
Determination of Reactor Coolant Temperature From Diverse Measurements

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements to provide adequate justification for determining the reactor coolant temperature of pressurized water reactor (PWR) power plants by the use of diverse measurements.

This Part establishes measurement methods, parameters to be measured and evaluated, accuracy criteria, and records requirements so that reactor coolant temperature sensors can be calibrated in situ.

1.2 Applicability

(a) This Part provides a method for deriving reactor coolant system (RCS) temperatures from measured steam generator (SG) pressure. The RCS temperature is the sum of SG saturation temperature and the primary-to-secondary differential temperature. SG saturation temperature is directly related to RCS temperature through an overall heat transfer coefficient when positive, steady state, primary-to-secondary heat transfer is in progress. This heat transfer causes a primary-to-secondary temperature differential, which can be

(1) estimated by calculation

(2) forced to negligible values via specific plant conditions

(3) established by direct measurement

(b) This Part may be used to determine reactor coolant temperature by the use of SG pressures or temperatures.

(c) This Part shall only be used under saturated steam conditions. Plants that use superheated SGs shall ensure that they are operating in a saturated condition when this Part is used.

(d) This Part shall only be used under no-load conditions. It is best used under hot, no-load conditions where the ratio of steam pressure to temperature is the highest. At lower temperatures, there will be a corresponding decrease in accuracy.

(e) This Part has no acceptance criteria or corrective actions. It is used as a tool to determine RCS temperature. Plant procedures for calibrating reactor coolant temperature sensors may use the results of this Part for acceptance criteria requirements.

1.3 Basic Methodology

The methodology of this Part is to measure the SG pressure, convert the pressure to a saturation temperature, and then relate the steam saturation temperature to the isothermal temperature of the RCS. To determine the isothermal temperature of the RCS, the difference between the RCS temperature and the SG saturation temperature (ΔT_{ps}) shall be known.

The three basic methodologies for determining ΔT_{ps} are as follows:

(a) heat transfer calculation or analysis

(b) SG isolation

(c) direct measurement

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part.

constant: associated parameters maintained within the limits assumed in the uncertainty analysis.

isothermal condition: reactor coolant fluid in the loops and reactor vessel at essentially the same temperature and constant (except for deviations due to operating the loops with the reactor shut down).

no-load condition: steady state thermal load below the point of adding nuclear heat.

reactor coolant system (RCS): for this Part, the RCS consists of the major reactor coolant piping in the PWR, including the SG primary side and the reactor vessel.

SG: steam generator.

square root of the sum of the squares (SRSS): a method of combining uncertainties by using the SRSS of the random uncertainties.

steam tables (published by ASME): the 1997 Properties for Industrial Use tables based on the IAPWS-IF97 formulation are preferred, but any steam table approved by the Owner and/or nuclear steam supply vendor is acceptable.

ΔT_{ps}*:* temperature difference between the primary and secondary sides of the SG.

3 REFERENCES

The following is a list of publications referenced in and/or related to this Part.

ISA RP67.04, Part II, Methodologies for the Determination of Setpoints for Nuclear Safety Related Instrumentation

NRC Branch Technical Position HICB 13, Guidance on Cross-Calibration of Protection System Resistance Temperature Detectors (Revision 4), U.S. Nuclear Regulatory Commission, June 1997

Publisher: Superintendent of Documents, U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

4 REQUIREMENTS

4.1 Plant Conditions

Use of this Part entails that minimum plant conditions be established to ensure that data taken are representative of the RCS temperature. These conditions shall be maintained throughout the period of measurements specified by this Part.

Plant parameters shall be established to maintain the RCS as close as possible to isothermal conditions. Parameters that can affect temperature differences between RCS loops and/or portions of RCS loops shall be identified and evaluated.

To obtain the maximum accuracy possible by the use of this Part, the RCS temperature shall be at or near maximum temperature for no-load condition. However, this Part may be used at lower temperatures provided it is taken into account in the uncertainty analysis.

(a) The RCS temperature shall be held constant.

(b) Sufficient reactor coolant pumps shall be in operation to establish isothermal conditions. It is not necessary for all reactor coolant pumps to be in operation.

(c) SG pressure shall be maintained within the assumptions made in the uncertainty analysis.

(d) Feedwater and SG blowdown flow, if operating, shall be held constant. Operation of feedwater and SG blowdown systems shall be evaluated because it influences the temperature difference across the SG tubes and may have an impact on isothermal conditions.

(e) Steady state isothermal conditions shall be maintained throughout the measurement.

(f) RCS shall be under a no-load condition.

4.2 Test Equipment

(a) Test equipment shall be calibrated in accordance with the Owner's test equipment program.

(b) Test equipment shall be designed for process and environmental conditions including instrumentation directly exposed to steam.

(c) Test equipment, including permanently installed instrumentation, shall be selected based on the ability to stay within the assumptions of the uncertainty analysis. See Nonmandatory Appendix A of this Part for uncertainty guidance.

4.3 Uncertainty Methodologies

Uncertainties related to data collection techniques, current operating conditions, calculations, test equipment, and results shall be documented. As a minimum, the following parameters shall be considered for the uncertainty analysis to ensure accuracy of the results.

4.3.1 Operating Conditions

(a) RCS Temperature. If a plant is controlling to RCS temperature, the plant-specific RCS temperature control band shall be considered.

(b) Steam Pressure. If a plant is controlling to SG pressure, the plant-specific pressure control band, as it relates to RCS temperature, shall be considered.

(c) Steam Pressure Differences. For conditions where SGs are not isolated and are connected to a common header, steam pressures shall be averaged and uncertainties calculated accordingly. For SGs that are isolated or not connected to a common header, steam pressures shall be measured separately by SG and uncertainties calculated accordingly. SG pressure indications shall be combined in accordance with assumptions in the measurement uncertainty analysis. Dynamic head losses in the steam lines are negligible at no-load conditions.

(d) Decay Heat. If significant decay heat is present, the uncertainties associated with the decay heat shall be considered.

(e) Net Heat Addition Parameters. Uncertainty of parameters associated with RCS heat additions and losses shall be considered.

(f) SG Blowdown Flow. Uncertainty in the SG blowdown flow measurement shall be considered.

(g) Feedwater Flow Measurement. Uncertainty in the feedwater flow measurement shall be considered.

4.3.2 Test Equipment Uncertainties

(a) Uncertainties based on instrument range and accuracy shall be considered.

(b) Instrument uncertainties may be combined statistically using the SRSS of the random uncertainties and the sum of the bias uncertainties.

(c) Several independent instruments may be used to reduce the random errors associated with using the SRSS method.

Nonmandatory Appendix A of this Part provides more detailed guidance on instrument uncertainties.

5 DEVELOP TEST PROCEDURES AND PERFORM TESTING

Procedures shall provide a method for deriving RCS temperatures from measured SG pressure. SG saturation temperature is directly related to RCS temperature through an overall heat transfer coefficient. The heat transfer causes a primary-to-secondary temperature differential. The RCS temperature is the sum of SG saturation temperature and the primary-to-secondary differential temperature (ΔT_{ps}).

5.1 Establish Primary-to-Secondary Side ΔT_{ps}

The test procedure shall use one or more of the following three methods to determine the difference between the RCS temperature and the SG saturation temperature:

(a) heat transfer calculation or analysis (see para. 5.1.1)

(b) SG isolation (see para. 5.1.2)

(c) direct measurement (see para. 5.1.3)

5.1.1 Establish ΔT_{ps} by Means of Heat Transfer Calculation or Analysis. The objective of this method is to establish primary-to-secondary temperature differential by using a heat transfer calculation or analysis. The RCS temperature can be directly related to SG saturation temperature when heat is being removed from the RCS by steaming. A single overall heat transfer coefficient can be derived by a calculation or measurement analysis. The coefficient shall be representative for the condition as defined in subparas. 1.2(c) and 1.2(d) and take into account SG feedwater flow, blowdown, level, pressure, SG tube plugging/fouling, and primary system average temperature. Although the uncertainties in calculated heat transfer coefficients may be relatively large, the absolute differential temperature errors become small under no-load conditions.

Various industry computer programs for SG design are available for estimating the necessary heat transfer coefficient. In determining the appropriate coefficient, the steady state condition over which the calculated coefficient is valid shall be established because significant changes in heat transfer mode can take place under different operating conditions.

5.1.2 Establish ΔT_{ps} by SG Isolation. The objective of this method is to force ΔT_{ps} for one or more SGs as close to zero as practically possible, eliminating the need for a heat transfer calculation or analysis. Depending on the required accuracy, ΔT_{ps} can be assumed to be zero.

The methodology requires the isolation of one or more SGs and shutdown of the associated primary pump(s) of the isolated SG. Once the SG is isolated and the primary pump shut down, the (colder) primary coolant will reverse and the SG's steady state inventory will reach, after some time, a temperature very close to the primary coolant flowing through the SG tubes. This results in a very small ΔT_{ps} that can be expected to be negligible.

Equilibrium is reached when the heat loss of the isolated SG equals the heat loss of primary coolant to the SG inventory. A stable steam pressure of the isolated SG indicates equilibrium. Although the heat addition of the primary pump(s) is expected to be negligible, because the primary pump(s) is switched off for the isolated loop(s), there is no error introduced as a result of the rise in temperature of the primary pump hydraulic efficiency and (part of the) primary pump's head rise. Plant design configurations such as long or outside steam piping and weather conditions may have an impact on heat transfer in isolated SGs and shall be considered.

This method only provides RCS temperature values for the SG loops being isolated.

5.1.3 Establish ΔT_{ps} by Direct Measurement. This method determines ΔT_{ps} by direct measurement. The test to establish the primary-to-secondary differential temperature shall be performed once and shall employ at least one recently calibrated precision temperature instrumentation device to minimize uncertainties. The conditions at which the test is performed shall be repeated if the ΔT_{ps} is to be used for future reference. Changes in fouling and tube plugging can affect the accuracy of ΔT_{ps} for future use. Minimizing the heat load minimizes the error of ΔT_{ps}. Consider setting blowdown to zero during the test and for future calibrations using the ΔT_{ps} value.

5.2 Test Procedure Development

(a) Unless the direct measurement or the SG isolation methodology is used to determine SG ΔT_{ps}, heat transfer coefficients shall be calculated for use in test procedures. It is not required that the heat transfer coefficient calculations be part of the test procedure.

(b) Test procedures developed to perform this Part shall include references to the methodology of determining the temperature difference across the SG tubes, as described in para. 5.1.

(c) Test procedures shall consider uncertainty methodologies for test equipment, data collection techniques, current operating conditions, calculations, and results, as established in para. 4.3.

(d) Test procedure measurement requirements shall ensure that plant conditions remain within the operational limits assumed in calculation or measurement of heat transfer coefficients.

(e) It should be noted that, during the heating of the SG inventory, the steam pressure rises relatively easily as a result of the natural circulation within the SG. However, if the primary coolant temperature drops, the SG pressure response will be extremely slow due to the natural circulation in the SG inventory practically stopping. The procedure shall make provisions to invalidate the test if RCS temperature is not held steady (or on a slight incline).

5.3 Perform Test

(a) *Initial Test Conditions.* Establish initial plant conditions identified in para. 4.1.

(b) Steam Pressure. Steam pressure measurements shall be obtained in a manner consistent with the uncertainty analyses described in para. 4.3.

(c) Saturation Temperature. Determine saturation temperature at the surface of the SG from steam pressure measurement using ASME or other approved steam tables. Ensure steam head corrections are considered.

(d) Final RCS Temperature. Apply SG ΔT_{ps} determined in para. 5.1 to saturation temperature to obtain final RCS temperature.

(e) If using this Part for in situ calibration of reactor coolant temperature sensor resistance temperature detectors (RTDs), compare the final RCS temperature to RTD measurement results. Determine if results are consistent with plant uncertainty calculations.

6 DOCUMENTATION

The basis for establishing SG ΔT_{ps}, plant test conditions, and uncertainties shall be documented in accordance with the Owner's quality assurance program.

Part 26, Nonmandatory Appendix A
Measurement Equipment Uncertainties

The measurement uncertainties are usually specified as a percentage of calibrated instrument range. The accuracy of the measurement can be improved by selecting instrumentation that is calibrated to a range close to the expected reading. Ensure that the instrumentation is not over-ranged during the test. Uncertainties may be combined statistically using the SRSS of the random uncertainties and the sum of the bias uncertainties. Refer to ISA RP67.04 for combining uncertainties. The methodology used for combining uncertainties shall provide a confidence level of at least 95% or 2σ.

Several independent instruments may be used to reduce the random errors associated with the instruments using the SRSS method. If numerous readings are taken due to data scatter, the mean should be calculated using at least 30 data points.

As a minimum, the following measurement equipment uncertainties shall be considered. These uncertainties may be included in the instrument uncertainty calculation, or the instrument reading may be corrected to remove the uncertainty (i.e., static water head pressure and line pressure corrections are usually included in the calibration of plant instrumentation).

(a) Measurement and Test Equipment (M & TE) Accuracy. The accuracy of M & TE used to measure plant parameters or to calibrate permanent plant instrumentation.

(b) Reference Accuracy. Including conformity (linearity), hysteresis, deadband, and repeatability.

(c) Power Supply Voltage and Frequency Fluctuations. Electronic instrumentation is affected by variations in the power supply voltage and frequency. The manufacturer usually provides this effect.

(d) Temperature Effect. The difference in the ambient temperature between the last calibration and the temperature at the time of measurement can introduce a significant effect on the instrument.

(e) Static Pressure Effect. Changes in the output of instrumentation due to changes in the process or ambient pressure. Static pressure effect due to changes in ambient pressure can be caused by the use of a gage pressure instrument in a building that is not at atmospheric pressure. The instrument manufacturer usually provides process pressure uncertainty effect.

(f) Humidity Changes. The effect of changes in the ambient humidity on the instrument accuracy.

(g) Analog-to-Digital (A-D) Conversion, Digital-to-Analog (D-A) Conversion, and Digital Signal Processing. This introduces an uncertainty that varies with the conversion method and the number of bits used in the conversion.

(h) Instrument Drift. The change in the reading between the last calibration and the measurement.

(i) Readability. The readability of analog indications shall be considered in the uncertainty analysis. An analog indicator can be read to half of the smallest scale division.

Part 28
Standard for Performance Testing of Systems in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for preservice and inservice testing to assess the operational readiness of certain safety-related systems and systems important to safety used in light-water reactor power plants.

The systems covered are those required to perform or support a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements for assessing integrated system performance.

1.2 Exclusions

1.2.1 Use of this Part for a chosen system or systems within the Scope does not mandate application to all systems within the Scope.

1.2.2 This Part does not address nonsystem-level testing of components, instrumentation, and controls. Implementation of the applicable Codes and Standards that defines such testing is assumed. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

1.3 Owner's Responsibilities

1.3.1 Identify the system(s) to be tested in accordance with this Part. The identified systems could include any systems requiring a performance testing program based on the Owner's evaluation of regulatory issues or other Owner considerations.

1.3.2 Establish a test program for each system identified per para. 1.3.1 with the following elements:

(a) establish the boundaries for each system or portion of system subject to the requirements of this Part (see para. 4.1)

(b) identify performance requirements from licensing and design basis documentation (see para. 4.2)

(c) identify testable characteristics that represent performance requirements (see para. 4.3)

(d) establish test acceptance criteria for each characteristic (see para. 4.4)

(e) develop test procedures that include test acceptance criteria and test frequencies, and perform required testing, inspections, and engineering analysis (see para. 4.5)

(f) evaluate test data and implement corrective action as appropriate (see section 6)

(g) document and retain a test plan and test results (see section 7)

1.3.3 Use specific system test program requirements identified in section 5, as applicable.

1.3.4 Apply the appropriate quality assurance requirements to this program.

1.3.5 Review industry operating experience as an input to the development of this program (see Nonmandatory Appendix A of this Part).

1.3.6 Develop the test program within the bounds of the plant's design basis; do not violate the plant's design basis as a result of testing under this Part. Consider the required test conditions and the potential consequences of the testing when developing the test program. Develop the test program to minimize the impact to plant risk while the test is being performed. Define contingency actions, as appropriate, to manage plant risk during testing. Examples include increased oversight, use of dedicated plant operators, and termination criteria. If a specific test within the program would be impractical, cause detrimental interactions, or conflict with the design basis, engineering evaluation or analysis is allowed in lieu of the specific test. Refer to para. 4.5 for additional guidance.

2 DEFINITIONS

acceptance criteria: specified limits placed on characteristics of an item, process, or service defined in codes, standards, or other required documents.

accuracy: the closeness of agreement between a measured value and the true value.

actuation levels: a response to defined plant conditions that will control or actuate a desired set of components.

auxiliary feedwater system (AFWS): a system that provides inventory to the steam generators (PWR) or reactor

(BWR) for heat removal when normal feedwater is unavailable.

characteristic: a variable or attribute that can be verified by direct measurement or data reduction.

closed cooling water system (CCWS): a closed intermediate heat transfer system between supported structures, systems, and components and the ultimate heat sink.

component: an item such as a vessel, pump, valve, piping product, or core support as an entity for purposes of reporting or analyzing.

design bases: information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design.

emergency core cooling system (ECCS): an automatic or manual safety system credited in the plant 10 CFR 50.46 (Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors) analysis, or equivalent analysis, for injecting coolant to the reactor core or removing heat directly from the core coolant.

engineered safety features actuation system (ESFAS): a system that responds to input parameters to actuate required components in accordance with specified actuation levels.

least margin condition: the operating mode for the system where the characteristic being tested is closest to the operating limit.

maintenance: replacement of parts, adjustments, and similar actions that do not change the design (configuration and material) of an item.

modification: alteration in the design of a system, structure, or component.

open cooling water system: an open loop heat transfer system from supported structures, systems, and components directly to the ultimate heat sink.

preservice test: a test performed after completion of construction activities related to the component and before first electrical generation by nuclear heat, or in an operating plant, before the component is initially placed in service.

response time: time elapsed from when the process exceeds a setpoint until the component achieves the required response.

support system: any system that is necessary for the tested system to perform the intended function.

system: an assembly of components whose functions and limitations are defined in design or system specification documents.

3 REFERENCES

(a) ASME OM-S/G–2000, Part 21, Inservice Testing of Heat Exchangers
(b) ASME Steam Tables, 5th Edition

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

(c) Flow Measurement Engineering Handbook. Miller, R. W. 2nd Edition. New York: McGraw-Hill, 1989

Publisher: McGraw-Hill Professional, Two Penn Plaza, New York, NY 10121

4 GENERAL TESTING REQUIREMENTS

This section provides generic direction for the first five elements of the test program outlined in para. 1.3.2. As applicable, specific system testing requirements are defined in section 5.

4.1 Establish System Test Boundaries

For system(s) identified per para. 1.3.1, establish the boundaries for system testing. Include within the test boundaries the portions of the system(s) that perform the functions described in para. 1.1. Appendices to this Part contain descriptions of test boundaries for certain systems.

Testing of support systems for the system(s) identified above, such as those providing electrical supply, heat rejection, chemical addition, engineered safety features actuation system (ESFAS) logic, or emergency core cooling system (ECCS) actuation logic, is not within the scope of this Part.

Consider the interaction of nonessential components that may affect system operation by isolation, leakage, or additional heat loads when establishing the test boundary. In some cases, the system test boundaries may include nonessential portions of the system or supporting systems that cannot be isolated. Testing of nonessential portions of the system is only required to the extent of verifying that there is no adverse impact on the performance of those portions of the system within the scope of this Part.

4.2 Identify System Performance Requirements

Identify performance requirements for the portions of the system within the established test boundaries. Input parameters derived from safety analyses and design basis documentation define the performance requirements. Examples include required heat removal rates, required flow rates and distribution, system fluid temperature, and time to reach full flow after system actuation.

Identify performance requirements in a manner consistent with the plant licensing and design bases, including relevant licensing commitments that limit, modify, or clarify system operating requirements. Use source information that defines system performance requirements. Source information may include

(a) nuclear steam supply system design specifications
(b) architect-engineer specifications
(c) safety analysis report (SAR)/updated safety analysis report (USAR)
(d) safety evaluation report/supplemental safety evaluation reports
(e) technical specifications
(f) design basis documentation
(g) vendor correspondence

When direct testing of each of the performance requirements is not practical, develop testable system characteristics in accordance with para. 4.3 that can be used to verify performance requirements.

4.3 Identify Testable Characteristics

(a) Identify testable characteristics that can be used to confirm system performance requirements are met. Use source information that defines system characteristics. Source information, in addition to that identified in para. 4.2, includes

(1) design calculations
(2) system descriptions
(3) plant system specific drawings
(4) preoperational tests
(5) design change documentation

(b) System characteristics are variables or attributes that can be verified by direct measurement or data reduction. The system characteristics include component characteristics, instrumentation and control characteristics, and logic characteristics that impact system-level performance. System characteristics associated with typical system operation are

(1) system and branch line flows for each system alignment
(2) total heat rejection capacity
(3) system operating temperatures
(4) maintaining system operation during system transients
(5) operation in response to actuation signals with and without offsite power

The values of some system characteristics cannot be directly measured but can be calculated. Examples are pump total dynamic head and heat removal rate.

4.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics. An example is pump performance required to deliver design flow to the supported components within a defined time interval after an initiating event.

4.3.2 Instrumentation and Control (I&C) Characteristics. Include instrumentation and control characteristics that affect system-level performance as system characteristics. These include indication and control of system parameters such as flow, pressure, level, temperature, and component status.

4.3.3 System Logic Characteristics. Include system logic characteristics as system characteristics. System logic is any permissive or interlock that actuates or aligns system components. System logic does not include ESFAS or ECCS actuation logic. Examples of system logic are

(a) logic intended to start standby pumps on flow or pressure demand
(b) logic for system realignment to accident mode from any nonsafety or secondary operating mode
(c) logic for heat exchanger bypass or temperature control

4.4 Establish Acceptance Criteria

Establish acceptance criteria for each of the system characteristics derived in accordance with para. 4.3. Each system characteristic has analysis limits that are found in the plant design or licensing basis documentation and other source information described in paras. 4.2 and 4.3. Develop test acceptance criteria from these limits that account for

(a) differences between analysis and test considering system configuration and boundary or process fluid conditions. Since system testing under accident conditions may be impractical, acceptance criteria must be developed by correlating accident analysis limits to practical test conditions. For example, the heat load from initiating events may not be achievable during test conditions.

(b) test instrument loop accuracy. Accomplish this by adjusting either the measured data or the analysis limits. Refer to Nonmandatory Appendix B, section B-4 of this Part for an example of this adjustment process for pump TDH versus flow. Refer to Nonmandatory Appendix C of this Part for guidance on test instrument accuracy. Use instruments that provide sufficient accuracy to ensure that the minimum design performance requirements of the system are being met, assuming maximum instrument error.

Review and revise as necessary all applicable acceptance criteria prior to the performance of each system functional test to ensure that changes in performance requirements caused by repairs or modifications are taken into account.

4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

(a) Develop and approve test procedures to verify that acceptance criteria derived in accordance with para. 4.4 are met. Participation by organizations responsible for maintaining the design basis is required in developing test acceptance criteria and procedures. Use

available operating experience (OE) information. Industry and government agency experience reports and databases give additional insights into system operation and testing. Nonmandatory Appendix A of this Part provides a summary of pertinent industry information.

Consider the required test conditions, detrimental interactions, and potential consequences of testing when developing the test procedure. Evaluate the risk impact of testing, in accordance with existing plant risk management programs, and schedule the test performance to minimize the impact to plant risk. Define contingency actions, as appropriate, to manage plant risk during testing. Portions of the system test may be performed at different plant operating modes in a manner consistent with managing plant risk.

Include specific requirements in the test procedure for data collection that support the acceptance criteria. Various means of data collection can be used, such as manual log, automatic data logger, or plant computer and must consider the need for historical retention to support data trending. Where appropriate, record as-found condition of tested parameters and document any reperformance of testing.

(b) This Part does not require simultaneous testing of all system components, subsystems, and support systems. A logical combination of several separate tests is acceptable; however, integrate the testing where practical. For example, the thermal and hydraulic performance of heat exchangers can be determined under different conditions and combined by evaluation to demonstrate acceptable system performance. If separate tests are used to collect data for specific characteristics, analyze the test results to correlate with results that would have been obtained under simultaneous testing.

Ensure all interfaces are properly tested and verified. Operation of the supported (first line) systems may not be necessary. Credit for other testing, such as component testing performed under guidance from other standards, can be used to demonstrate proper system performance. Perform testing at plant conditions as close as practical to those expected during system operation. Identify test conditions that are different from conditions with least margin (e.g., temperature and pressure) when testing at least margin conditions is not practical or could potentially damage equipment. Perform analysis to account for differences between least margin and test conditions.

(c) Data from plant transients or inadvertent system actuations may be used if necessary analyses and supporting documentation are available. If the system is in continuous operation throughout the full range of reactor operation, performance adequacy can be determined by monitoring of the system instrumentation. Normal periodic data logging by various means provides trend data for evaluation of heat exchanger fouling, pump wear characteristics, or flow rate changes.

Engineering evaluations may be performed if integrated testing is not practical. Consider the required test conditions and the potential consequences of the testing in the evaluation of practicality. Use testing rather than evaluation wherever possible.

(d) This Part does not address nonsystem-level testing of components, instrumentation, and controls. Implementation of the applicable codes and standards that defines such testing is assumed. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

(e) If tests are performed at conditions different from those assumed in the calibration process for the instruments, recalibrate the instruments for the test conditions, use alternate instruments, or adjust the data to compensate for this difference.

4.5.1 Preservice Testing. Develop and conduct tests to measure system performance. The test results are used to determine that the system, component, I&C, and logic characteristics meet the associated acceptance criteria. The following subparagraphs provide requirements for preservice testing of some of the system characteristics described in para. 4.3:

(a) Conduct preservice testing under each set of conditions defined in the test plan to confirm the system's performance capability.

(b) Results of system startup tests may be used to satisfy the preservice testing requirements of this Part provided all other related requirements of this Part are met.

4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing to ensure that the system is functional. Perform prerequisites in any order and overlap component and logic testing sufficiently to verify proper installation. Perform the following prerequisites, as a minimum:

(a) electrical systems have been tested, including protective devices

(b) logic has been verified to function properly without actual starting of major components

(c) control, alarm, and indication instrumentation loops have been calibrated

(d) system flushing or blowdown has verified system cleanliness

(e) temporary construction components, such as strainers, jumpers, etc. have been removed or have been evaluated as required to support testing

(f) required pipe supports have been installed

(g) system and components have been installed, filled, and vented per design requirements

(h) system leak or pressure tests have been completed satisfactorily

(i) valves stroke when operated by control switches

(j) pump or compressor and motor checkouts have been completed per vendor recommendations, including proper rotation checks

(k) valve lineups are complete and will ensure that pump minimum flow and runout are met and any flow limits on heat exchangers will not be exceeded

(l) required chemical control has been established

(m) required support systems are available to support system testing

(n) relief valves have been bench-tested to verify setpoints

4.5.1.2 Preservice Performance Test. Develop and conduct tests that address the following requirements, as applicable, for each operating mode:

(a) During pump or compressor operation, monitor the system for unacceptable noise, vibration, or cavitation.

(b) Verify that pipe and component supports are within allowable limits at normal system operating temperature.

(c) Test integrated system operation in conjunction with other systems that could interact with the system during accident conditions. For example, branch line flows that are not isolated need to be considered for flow diversion and heat load addition.

(d) Test for adequate NPSH and acceptable pressure drop in suction lines and valves from the sources to the pump suction under maximum flow conditions.

(e) Verify automatic start of standby pumps and proper automatic alignment of valves and standby heat exchangers under a simulated emergency actuation signal.

(f) Verify that a single or multiple pump trips in a system utilizing pumps operating in parallel will not result in an electrical overload trip of the operating pump/motor, runout conditions on a pump, or NPSH problems for the remaining pump(s).

(g) For the set throttle valve positions or restriction orifice sizes, verify that no pump combination will result in

(1) inadequate or excess flow conditions to each branch line or serviced component

(2) pump flow less than minimum required flow

Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Reperform the applicable flow testing when such modifications have been made. Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and allowed for in the system flow balancing.

(h) Verify that system response during postulated transients, including loss of offsite power, is adequate to ensure that system operation is not compromised, including

(1) the system realigns without loss of function due, for example, to voiding, water hammer, or draining of a surge tank

(2) stroke times of boundary valves are within design requirements

(i) Verify operation of bypass temperature or pressure control systems, including surge tank pressure control systems, where provided.

(j) Check hot side to cold side pressure differential for heat exchangers to ensure pressure differential is within the design limit and in the appropriate direction.

(k) Verify proper operation of manually controlled components.

(l) Verify system leakage, including pressure boundary and isolation valves, is within design assumptions.

(m) Verify proper heat exchanger performance using methods described in Reference 3(a).

(n) Test pump discharge flow path overall resistance and balanced branch line resistance for all flow paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, sections B-5 through B-7 for guidance.

(o) Test the system characteristic of pump operation. For systems with multiple operating points, verify pump total dynamic head versus flow, using a five point (or greater) test, distributed between minimum and maximum expected flow rate. For systems with a narrow operating point range, select a suitable number of pump test points. Note that testing in accordance with component-level pump codes might not verify this system characteristic due to differences in testing method and acceptance criteria. Refer to Nonmandatory Appendix B, section B-4 for further guidance.

(p) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside the acceptable operating range.

4.5.1.3 Preservice Test Interval. Perform preservice tests prior to plant fuel load. Evaluate the acceptability of the interval between completion of each of the prerequisite tests described in para. 4.5.1.1 and the related performance testing of para. 4.5.1.2. Evaluate the acceptability of the interval between completion of any preservice test and the time when a system has been declared in service and governed by inservice test interval.

Portions of the preservice testing may be deferred if required conditions for testing cannot be met until after plant fuel load. Base the deferral of the testing on engineering evaluation to determine the impact on plant safety. Perform deferred testing as soon as practical after the required plant conditions have been met.

4.5.2 Inservice Testing. Develop and conduct tests to measure system performance. The test results are used to determine that the system, component, I&C, and logic characteristics meet the associated acceptance criteria. The following subparagraphs provide requirements for inservice testing of some of the system characteristics described in para. 4.3:

(a) Conduct inservice testing under each set of conditions defined in the test plan to confirm the system's performance capability.

(b) Procedures or test programs established for other purposes (e.g., inservice testing, surveillance testing, maintenance rule) may be used to satisfy testing requirements of this Part to the extent that they meet the requirements of this Part.

(c) Testing of individual components or groups of components or measurement of individual parameters may be performed at different times, provided overall system performance is not affected by separation of the individual tests and provided that all required tests are performed within the specified test frequency.

4.5.2.1 Inservice Performance Test. Develop and conduct tests that address the following requirements, as applicable, for each operating mode:

(a) During pump or compressor operation, monitor the system for unacceptable noise, vibration, or cavitation.

(b) Verify that pipe and component supports are within allowable limits at normal system operating temperature.

(c) Test integrated system operation in conjunction with other systems that could interact with the system during accident conditions. For example, branch line flows that are not isolated need to be considered for flow diversion and heat load addition.

(d) Test for adequate NPSH and acceptable pressure drop in suction lines and valves from the sources to the pump suction under maximum flow conditions.

(e) Verify automatic start of standby pumps and proper automatic alignment of valves and standby heat exchangers under a simulated emergency actuation signal.

(f) Verify that a single or multiple pump trips in a system utilizing pumps operating in parallel will not result in an electrical overload trip of the operating pump/motor, runout conditions on a pump, or NPSH problems for the remaining pump(s).

(g) For the set throttle valve positions or restriction orifice sizes, verify that no pump combination will result in

(1) inadequate or excess flow conditions to each branch line or serviced component

(2) pump flow less than minimum required flow

Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Re-perform the applicable flow testing when such modifications have been made. Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and allowed for in the system flow balancing.

(h) Verify that system response during postulated transients, including loss of offsite power, is adequate to ensure that system operation is not compromised, including

(1) the system realigns without loss of function due, for example, to voiding, water hammer or draining of a surge tank

(2) stroke times of boundary valves are within design requirements

(i) Verify operation of bypass temperature or pressure control systems, including surge tank pressure control systems, where provided.

(j) Check hot side to cold side pressure differential for heat exchangers to ensure pressure differential is within the design limit and in the appropriate direction.

(k) Verify proper operation of manually controlled components.

(l) Verify system leakage, including pressure boundary and isolation valves, is within design assumptions.

(m) Verify proper heat exchanger performance using methods described in Reference 3(a).

(n) Test pump discharge flow path overall resistance and balanced branch line resistance for all flow paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, sections B-5 through B-7 for guidance.

(o) Test the system characteristic of pump operation. For systems with multiple operating points, verify pump total dynamic head versus flow, using a five point (or greater) test, distributed between minimum and maximum expected flow rate. For systems with a narrow operating point range, select a suitable number of pump test points. Note that testing in accordance with component-level pump codes might not verify this system characteristic due to differences in testing method and acceptance criteria. Refer to Nonmandatory Appendix B, section B-4 for further guidance.

(p) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside its acceptable operating range.

4.5.2.2 Inservice Test Interval

(a) Establish a 5-yr ±25% initial test interval for the inservice testing described in para. 4.5.2. After each test, establish the subsequent test interval based on evaluation of the test results, including trending, performed in accordance with section 6. If the test interval is extended, the maximum allowable interval is 10 yr. Determine subsequent intervals for testing in accordance with this Part based on evaluation of the test results and other plant and industry information, such as equipment history records, test results, safety significance, and risk assessments. Include results of each evaluation in the test records.

(b) Test heat exchanger heat removal capability at the interval described in Reference 3(a).

(c) Perform the applicable portions of para. 4.5.2 prior to returning the system to service following replacement, repair, maintenance, or modification to system components or systems that could affect the ability to meet system performance requirements identified per para. 4.2. Examples of such changes include

(1) replacing valve or valve internals

(2) changing valve throttled position, including limit switch stop settings

(3) resizing system restriction orifices

(4) replacing or trimming the pump rotating element

(5) changing system logic

(6) changing the system flow path

(7) heat exchanger tube plugging

(d) Credit may be taken for testing performed in accordance with other test programs meeting the requirements of this Part.

5 SPECIFIC TESTING REQUIREMENTS

Use the information in this section to supplement sections 1 through 4 for the following specific systems. Then, refer to sections 6 and 7 for evaluation and documentation requirements.

5.1 Emergency Core Cooling Systems

Refer to Mandatory Appendix I of this Part for specific direction and information regarding testing of BWR emergency core cooling systems.

Refer to Mandatory Appendix II of this Part for specific direction and information regarding testing of PWR emergency core cooling systems.

5.2 Auxiliary or Emergency Feedwater Systems

Refer to Mandatory Appendix III of this Part for specific direction and information regarding testing of auxiliary feedwater systems.

5.3 Closed Cooling Water Systems

Refer to Mandatory Appendix IV of this Part for specific direction and information regarding testing of closed cooling water systems.

5.4 Emergency Service Water Systems

Refer to Mandatory Appendix V of this Part for specific direction and information regarding testing of emergency service water systems.

5.5 Instrument Air Systems

Refer to Mandatory Appendix VI of this Part for specific direction and information regarding testing of instrument air systems.

6 EVALUATE TEST DATA

6.1 Compare Data to Acceptance Criteria

Evaluate the test data against the acceptance criteria established in accordance with para. 4.4. If test results fail to meet acceptance criteria, take corrective action in accordance with either of the following:

(a) Perform appropriate corrective actions on the nonconforming component or system, followed by retest.

(b) Perform evaluations to disposition the affected components or nonconforming systems portion. Refine the analysis on which the acceptance criteria are based such that the measured data meets the revised acceptance criteria and corresponding revision of the design, design basis, and licensing basis. Establish the revised acceptance criteria with sufficient margin to ensure acceptable performance until the next system test.

6.2 Trend Test Data

Compare as-found test data to corresponding prior as-left test data to identify significant trends in performance. Trends can be degradation, step changes, or anomalous test results. If analysis results identify adverse trends, investigate to determine the cause and take appropriate corrective action. Appropriate actions may include

(a) restoration of the baseline condition

(b) modification of the test interval or

(c) modification of the acceptance criteria

6.3 Evaluate Test Interval

Evaluate the test data to project future system performance by considering

(a) margin between acceptance criteria and system test results

(b) system performance data trending

(c) modification and maintenance history

(d) internal and external system service conditions (for example, biofouling, corrosion, erosion, and wear)

(e) frequency of operation

In addition, consider other plant and industry operating experience information that may influence a decision to change the test interval.

If the evaluation determines that satisfactory performance is ensured until the next system test, then consider extending the test interval. If the evaluation determines satisfactory performance until the next system test is not ensured, then either restore margin or reduce the test interval to ensure acceptable performance until the next system test.

7 DOCUMENTATION

For each system tested in accordance with this Part, document the basis for establishing test boundaries, identifying system performance requirements and testable characteristics, establishing acceptance criteria, and developing test procedures. Include in the basis a discussion of test scope decisions including any overlap with other test programs. Retain testing program procedures, results, deficiencies, data evaluations, and corrective actions for the life of the plant.

7.1 System Test Plan

Document or reference within each system test plan the following, as a minimum:

(a) a brief description of the system or portion of the system subject to testing, including a description of the basis for the system test boundaries

(b) a description of the system performance requirements being tested and basis for selection

(c) a list of all system components that are required to function in support of the system performance requirement(s)

(d) a list of the testable characteristic(s) that each component is required to perform

(e) the basis for the selection of acceptance criteria and instrument accuracy requirements for each testable characteristic

(f) the detailed procedures or instructions for performance of the tests

(g) a detailed description of and justification for all assumptions, postulations, extrapolations, or calculations used to determine acceptance criteria or to correlate test data with postulated least margin conditions

(h) a detailed description of all exceptions to the requirements of this Part, including justification and alternate testing, engineering evaluation, or analysis

(i) other information as specified in this Part

7.2 Test Results and Corrective Actions

Document the test results and corrective actions that result from each execution of the system test plan.

Part 28, Mandatory Appendix I
Specific Testing Requirements of Emergency Core Cooling Systems in BWR Power Plants

I-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency core cooling systems used in boiling water reactor (BWR) power plants perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

I-2 DEFINITIONS

condensate storage tank (CST): a storage tank containing water inventory for ECCS pump suction.

containment spray: a system to control containment pressure and temperature and to remove containment heat following accident conditions.

I-3 REFERENCE

Title 10, Code of Federal Regulations, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors

Publisher: U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

I-4 BWR ECCS TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for BWR ECCS.

I-4.1 Establish System Testing Boundaries

Establish the BWR ECCS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

Establish the system test boundaries for all ECCS as defined in para. 1.1 of this Part, such as low-pressure injection, high-pressure injection, passive injection, pumped recirculation, core spray, and automatic depressurization systems. Include within the test boundary all equipment required to perform the ECCS function of delivering water from the source to the reactor vessel or removing heat directly from the core coolant.

Include within the test boundaries portions of the following decay heat removal systems only when credited as ECCS or when they directly affect ECCS operation:

(a) normal feedwater
(b) auxiliary or emergency feedwater
(c) containment air cooling
(d) isolation condenser
(e) reactor core isolation cooling
(f) containment spray
(g) suppression pool cooling
(h) normal plant shutdown decay heat removal

For example, when establishing the test boundary, consider the interaction of the containment spray pumps with high head safety injection (SI) pump net positive suction head (NPSH) when the pumps simultaneously take suction from the low head SI pump discharge.

I-4.2 Identify System Performance Requirements

Identify system performance requirements for ECCS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ECCS examples beyond those of para. 4.2 of this Part include input parameters derived from safety analyses performed to meet the requirements of the reference in para. I-3, or equivalent, such as core delivered flow, ECCS fluid temperature, and time to reach full flow after ECCS actuation.

I-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ECCS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of core delivered flow.

I-4.3.1 Component Characteristics. Include ECCS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part.

I-4.3.2 Instrumentation and Control (I&C) Characteristics. Include ECCS instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

I-4.3.3 ECCS Logic Characteristics. Include ECCS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of ECCS logic are

(a) logic that prevents unintentional overriding of ECCS operation, such as defeating noncritical trips during emergency actuation and confirmatory signals to valves

(b) logic intended to prevent exceeding design limits, such as logic controlled flow limiters

(c) logic that causes ECCS components to actuate via an ESFAS or ECCS actuation signal

(d) logic for transfer of pump suction from the CST to the containment suppression pool

(e) interlocks, such as the pressure permissive logic for injection valves on low-pressure injection systems

(f) logic for ECCS injection path selection

(g) logic for system realignment to accident mode from any nonsafety or secondary operating mode

I-4.3.4 System Characteristics. Identify ECCS system characteristics for the high-pressure injection, depressurization, low-pressure injection, and long term decay heat removal modes. The following paragraphs provide some examples of system characteristics for the four operating modes. These examples are not to be considered all-inclusive.

I-4.3.4.1 High-Pressure Injection Mode Characteristics. System characteristics associated with the high-pressure injection mode are

(a) discharge flow path resistance for all injection paths

(b) for injection pump and driver operation,

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under worst-case flow conditions

(c) pump minimum flow path flow rate

(d) integrated ECCS operation in conjunction with other systems in response to ECCS actuation with and without offsite power

(e) transfer of pump suction from the CST to the suppression pool

I-4.3.4.2 Depressurization Mode Characteristics. System characteristics associated with the depressurization mode are

(a) blowdown mass flow rate

(b) initiation logic operation

I-4.3.4.3 Low-Pressure Injection Mode Characteristics. System characteristics associated with the low-pressure injection mode are

(a) discharge flow path resistance for all injection paths

(b) for injection pump and driver operation,

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) integrated ECCS operation in conjunction with other systems and divisions, where divisional interaction exists, in response to ECCS actuation with and without offsite power.

I-4.3.4.4 Long-Term Decay Heat Removal Mode Characteristics. System characteristics associated with long-term post-accident heat removal are

(a) flow resistance for all heat removal paths

(b) for heat removal pump and driver operation,

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) ECCS heat exchanger heat removal

I-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

I-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with para. 1.4.4 of this Part are met.

I-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

I-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

I-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applying to preservice testing that are beyond those stipulated in this Mandatory Appendix for inservice testing.

I-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

I-4.5.2 Inservice Testing. Develop and conduct tests to measure ECCS system performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in paras. I-4.3.4.1, I-4.3.4.2, I-4.3.4.3, and I-4.3.4.4.

I-4.5.2.1 High-Pressure Injection Mode. Inject water into the reactor vessel through each required injection path and pump combination as allowed by plant design. Test each ECCS train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test integrated ECCS operation in conjunction with other systems in response to ECCS actuation with and without offsite power. For at least one of these tests, deliver flow to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. I-4.5.2.5 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel.

(b) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. These tests should include transfer of pump suction between the CST and the suppression pool. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

I-4.5.2.2 Depressurization Mode

(a) Test the system characteristic of blowdown mass flow by opening the automatic depressurization system (ADS) valves and determining the mass flow rate. This may be accomplished by opening individual relief valves in any mode of operation and measuring appropriate parameters to obtain a mass flow rate.

Scale model or prototype testing of ADS valves to determine mass flow rate may be used in place of actual plant testing. An analytical evaluation is acceptable in lieu of testing if the scale model or prototype testing does not simulate discharge to the suppression pool. In the absence of verifying mass flow rate, ensure by other means that an unobstructed flow path exists. See para. I-4.5.2.5 for specific test frequency exceptions.

(b) Test the ADS initiation logic by verifying operation from the ECCS actuation signal through the valve actuator. Valve opening may be verified via other testing such as the relief mode operation.

I-4.5.2.3 Low-Pressure Injection Mode. Inject water into the reactor vessel through each required injection path and pump combination. Test each ECCS train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test integrated ECCS operation in conjunction with other systems and divisions, where divisional interaction exists, in response to ECCS actuation with and without offsite power. For at least one of these tests, deliver flow to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. I-4.5.2.5 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel.

(b) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

I-4.5.2.4 Long-Term Decay Heat Removal Mode. Test flow through each required decay heat removal path and pump combination. Test each decay heat removal train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

(b) Test heat exchanger ECCS decay heat removal capability.

I-4.5.2.5 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. Allowable exceptions to para. 4.5.2.2 of this Part are as follows:

(a) Conduct the integrated ECCS test with simultaneous flow from all interacting divisions [subparas. I-4.5.2.1(a) and I-4.5.2.3(a)] to the reactor vessel at a 10-yr +25% time interval.

(b) Suction vortex formation testing [subparas. I-4.5.2.1(b), I-4.5.2.3(b), and I-4.5.2.4(a)] need only be performed following any modification that affects

the corresponding performance requirements of para. I-4.2. This exception is allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

(c) Testing of the ADS valves in subpara. I-4.5.2.2(a) need only be performed following any modification that affects the corresponding performance requirements of para. I-4.2, provided there is objective evidence that the requirements of this paragraph have been met at least once.

Part 28, Mandatory Appendix II Specific Testing Requirements of Emergency Core Cooling Systems in PWR Power Plants

II-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency core cooling systems used in pressurized water reactor (PWR) power plants perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

II-2 DEFINITIONS

borated water supply tank (BWST): a storage tank containing borated water inventory for PWR ECCS pump suction during the injection phase.

containment spray: a system to control containment pressure and temperature and to remove containment heat following accident conditions.

II-3 REFERENCES

(a) Title 10, Code of Federal Regulations, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors

Publisher: U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

(b) Regulatory Guide 1.1, Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Safety Guide 1), U.S. Nuclear Regulatory Commission, November 1970

Publisher: U.S. Nuclear Regulatory Commission (NRC), 11555 Rockville Pike, Rockville, MD 20852 (www.nrc.gov)

II-4 PWR ECCS TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for PWR ECCS.

II-4.1 Establish System Testing Boundaries

Establish the PWR ECCS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

Establish the system test boundaries for all ECCS as defined in para. II-2, such as low pressure injection, high pressure injection, passive injection, pumped recirculation, and automatic depressurization systems. Include within the test boundary all equipment required to perform the ECCS function of delivering water from the source to the reactor vessel or removing heat directly from the core coolant.

Include within the test boundaries portions of the following decay heat removal systems only when credited as ECCS or when they directly affect ECCS operation:

(a) normal feedwater
(b) auxiliary or emergency feedwater
(c) steam generator heat removal
(d) containment air cooling
(e) containment spray
(f) normal plant shutdown decay heat removal

For example, when establishing the test boundary, consider the interaction of the containment spray pumps with high head safety injection (SI) pump net positive suction head (NPSH) when the pumps simultaneously take suction from the low head SI pump discharge.

II-4.2 Identify System Performance Requirements

Identify system performance requirements for ECCS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ECCS examples beyond those of para. 4.2 of this Part, include input parameters derived from safety analyses performed to meet the requirements of the reference in subpara. II-3(a), or equivalent, such as core delivered flow, ECCS fluid temperature, and time to reach full flow after ECCS actuation.

II-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ECCS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of core delivered flow.

II-4.3.1 Component Characteristics. Include ECCS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part.

II-4.3.2 Instrumentation and Control (I&C) Characteristics. Include ECCS Instrumentation and Control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

II-4.3.3 ECCS Logic Characteristics. Include ECCS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of ECCS logic are

(a) logic that prevents unintentional overriding of ECCS operation, such as defeating noncritical trips during emergency actuation and confirmatory signals to valves

(b) logic intended to prevent exceeding design limits, such as logic controlled flow limiters

(c) logic that causes ECCS components to actuate via an ESFAS or ECCS actuation signal

(d) logic for transfer of pump suction from the BWST to the containment sumps on a BWST low level signal

(e) interlocks, such as the logic for motor operated valves that isolate the decay heat removal system suction lines during normal operation and the safety injection accumulators before plant shutdown

(f) logic for system realignment to accident mode from any nonsafety or secondary operating mode

II-4.3.4 System Characteristics. Identify ECCS system characteristics for the passive injection, pumped injection, and pumped recirculation ECCS operating modes. The following paragraphs provide some examples of system characteristics for the three operating modes. These examples are not to be considered all-inclusive.

II-4.3.4.1 Passive Injection Mode Characteristics. A system characteristic associated with the passive injection mode is discharge flow path resistance from the safety injection accumulators to the RCS.

II-4.3.4.2 Pumped Injection Mode Characteristics. System characteristics associated with the pumped injection mode are

(a) pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths

(b) for injection pump and driver operation,

(1) NPSH for pump performance under worst-case system conditions

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) integrated ECCS operation in conjunction with other systems in response to ESFAS actuation with and without offsite power

II-4.3.4.3 Pumped Recirculation Mode Characteristics. System characteristics associated with the pumped recirculation mode are

(a) NPSH available is greater than that required at accident conditions (such as temperature, pressure, flow, and blockage) as discussed in the reference in subpara. II-3(b)

(b) pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths not addressed in para. II-4.3.4.2

(c) operation of each pump in all design operating modes not addressed in para. II-4.3.4.2, including pump drivers will not trip under worst-case flow conditions

(d) higher head pumps can be aligned for suction from the lower head pumps and operate acceptably in those plants that use this scheme in the pumped recirculation mode

(e) heat removal from ECCS heat exchangers

(f) transfer of pump suction from the BWST to the containment sump

II-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

II-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with para. II-4.4 are met.

II-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

II-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

II-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applicable to preservice testing that are beyond those stipulated in this Mandatory Appendix for inservice testing.

II-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

II-4.5.2 Inservice Testing. Develop and conduct tests to measure ECCS system performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in paras. II-4.3.4.1, II-4.3.4.2, and II-4.3.4.3.

II-4.5.2.1 Passive Injection Mode. Test the system characteristic of discharge flow path resistance from the safety injection accumulators to the RCS. Perform this test at a pressure sufficient to allow opening of all in-line check valves to their design basis flow position. See para. II-4.5.2.4 of this Mandatory Appendix for specific test frequency requirements and exceptions. See Nonmandatory Appendix B, section B-2 of this Part for technical guidance.

II-4.5.2.2 Pumped Injection Mode. Inject water from the BWST or other appropriate source into the reactor vessel through each required injection leg and pump combination as allowed by plant design. Test each ECCS train under cold operating conditions. The reactor vessel may be open and flooded during the testing, with the RCS pressure at essentially atmospheric pressure. There is no requirement to control BWST water temperature.

(a) Test integrated ECCS operation in conjunction with other systems in response to ESFAS actuation with and without offsite power. For at least one of these tests, deliver simultaneous flow from all trains to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. II-4.5.2.4 for specific test frequency requirements and exceptions for testing with simultaneous flow from interacting trains to the RCS.

(b) Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the sources to the pump suction under maximum flow conditions. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See subpara. II-4.5.2.4(b) for specific test frequency exceptions for vortex formation testing. Refer to Nonmandatory Appendix A of this Part for additional information.

II-4.5.2.3 Pumped Recirculation Mode

(a) Test the system characteristic of NPSH by taking suction from the containment recirculation sump. These tests should include transfer of pump suction between the BWST and the containment sump. Verify that vortex formation is minimized and that acceptable pressure drops exist across sump screens (clean and with postulated blockage), suction lines, and valves from the sump to the pump suction. Temporary sump modifications to provide adequate sump capacity for pump operation are acceptable. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel.

(b) Where actual plant testing is impractical, scale model testing of containment recirculation sumps, screens, and surrounding areas may be used. Include in the scale model design a scaling analysis that demonstrates that the test data will accurately reflect the actual system characteristics. Compare the inlet loss coefficient across the sump screens and sump intake piping to analytically determined values, and verify pump NPSH adequacy. If the scale model does not simulate the flow path from the sump to the respective pumps, an analytical evaluation of hydraulic losses in the flow path is acceptable in lieu of testing. See para. II-4.5.2.4 for specific test frequency exceptions.

(c) Verify by inspection or other means that an unobstructed pumped recirculation mode suction flow path will exist. An unobstructed flow path is free of flow path restrictions, or debris, that could adversely impact system function. Inspect containment areas in the postulated debris transport routes to the sump, the ECCS sump area inside the debris barrier, and the flow path from the ECCS sump to the respective pumps.

Test that higher head pumps can be aligned for suction from the lower head pumps and operate acceptably in those plants that use this scheme in the pumped recirculation mode.

NOTE: When testing pump discharge flow path overall resistance and balanced branch line resistance per subpara. 4.5.2.1(n) of this Part, pump suction may be aligned from alternate sources with appropriate analytical justification.

II-4.5.2.4 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. Allowable exceptions to para. 4.5.2.2 of this Part are as follows:

(a) Conduct the integrated ECCS test with simultaneous flow from all trains [subpara. II-4.5.2.2(a)] to the reactor vessel at a 10-yr +25% time interval.

(b) ECCS accumulator testing (para. II-4.5.2.1), containment sump testing [subpara. II-4.5.2.3(a)], and suction vortex formation testing [subparas. II-4.5.2.2(b) and II-4.5.2.3(a)] need only be performed following any modification that affects the corresponding performance requirements of para. II-4.2. This exception is allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

Part 28, Mandatory Appendix III Specific Testing Requirements of Auxiliary or Emergency Feedwater Systems in LWR Power Plants

III-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that auxiliary feedwater systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

III-2 DEFINITION

condensate storage tank (CST): a storage tank containing water inventory for AFWS pump suction.

III-3 REFERENCES

None.

III-4 AUXILIARY FEEDWATER SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for AFWS.

III-4.1 Establish System Testing Boundaries

Establish the AFWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part. Include within the test boundary all equipment required to perform the AFWS function of delivering water from the source to the steam generators (PWR) or reactor vessel (BWR).

For example, include within the system boundary all components (i.e., pumps, valves, piping, instrumentation) in the flow paths between the CST and the steam generators (PWR) or reactor (BWR).

III-4.2 Identify System Performance Requirements

Identify system performance requirements for AFWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific AFWS examples beyond those of para. 4.2 of this Part include delivery of minimum flow to the steam generators (PWR) or reactor (BWR) and time to reach full flow after AFWS actuation.

III-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical AFWS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of steam generator delivered flow (PWR).

III-4.3.1 Component Characteristics. Include AFWS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. Specific examples of component characteristics associated with AFWS components are

(*a*) net positive suction head (NPSH) for pump performance under system conditions with the least NPSH margin

(*b*) pump total dynamic head (TDH) versus flow

(*c*) pump response time (time to reach rated flow)

(*d*) pump drivers do not trip under flow conditions with the least margin to trip

(*e*) pump minimum flow path under individual and combined pump operation

(*f*) pump performance under parallel pump operation

III-4.3.2 Instrumentation and Control (I&C) Characteristics. Include AFWS instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

III-4.3.3 AFWS Logic Characteristics. Include AFWS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of AFWS logic are

(*a*) logic that causes AFWS components to actuate via an ESFAS, anticipated transients without scram (ATWS) mitigation circuitry, loss of offsite power and low steam generator level signal (PWR), or low reactor level (BWR) *(b)* logic that causes AFWS components to actuate when all feedwater pumps trip

III-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para 4.4 of this Part.

III-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with the requirements of para. III-4.4 are met.

III-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

III-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

III-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following AFWS-specific requirements:

(a) Verify that the AFWS is in the normal system standby alignment or operation. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated AFWS pumps are operating. Verify that system flow balancing requirements are maintained [e.g., flow to multiple steam generators (PWR)].

(b) Operate AFWS in each required operating alignment and pump combination as allowed by plant design. Test each AFWS train as close as practical to design conditions; however, all backpressure conditions are not required to be simulated simultaneously. Verify that the required flow is achieved on each branch line of AFWS.

Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the CST to the pump suction under maximum flow conditions. These tests should include transfer of pump suction between the CST and any alternate inventory source where applicable. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths if available.

III-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

III-4.5.2 Inservice Testing. Develop and conduct tests to measure AFWS performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in para. III-4.3.

III-4.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part and para. III-4.3. In addition, address the following AFWS-specific requirements:

(a) Verify that the AFWS is in the normal system alignment. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated AFWS pumps are operating. Verify system flow balancing requirements are maintained.

(b) Operate AFWS in the accident alignment with each required cooling water branch line and pump combination as allowed by plant design. Test each AFWS train as close as practical to design conditions. Verify that the required flow is achieved on each branch line of AFWS.

III-4.5.2.2 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. An allowable exception to para. 4.5.2.2 of this Part is that suction vortex formation testing (para. III-4.5.1.2) need only be performed following any modification that affects the corresponding performance requirements of para. III-4.2. This exception is allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

Part 28, Mandatory Appendix IV Specific Testing Requirements of Closed Cooling Water Systems in LWR Power Plants

IV-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that closed cooling water systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

IV-2 DEFINITIONS

process heat exchanger: a CCWS heat exchanger that rejects heat to the ultimate heat sink.

serviced heat exchanger: a heat exchanger in a supported system that rejects heat to the CCWS.

IV-3 CLOSED COOLING WATER SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for closed cooling water systems.

IV-3.1 Establish System Test Boundaries

Establish the CCWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all CCWS functions described in para. 1.1 of this Part. Include within the test boundary all equipment required to perform the CCWS function of transferring heat from the supported structures, systems, and components to the ultimate heat sink. This test boundary includes the interfacing heat exchangers for the heat sources and heat sinks for CCWS.

(a) Typical functions include

(1) decay heat removal

(2) containment heat removal

(3) pump and pump driver cooling

(4) room cooler heat removal

(5) chilled water system cooler heat removal

(6) containment high-energy penetration heat removal

(7) reactor support structure cooling

(8) system realignments including isolation of nonessential loops or branch lines

(9) heat removal and flow for nonessential loads that are not isolated, such as fuel pool cooling, sample coolers, and evaporators

(b) Figure IV-1 shows a simplified CCWS flow diagram and identifies some major components. Components of the typical CCWS may include

(1) CCWS process pumps

(2) control, isolation, throttling, and relief valves

(3) motor controllers, controls, and protective relays

(4) CCWS surge tank(s)

(5) instrumentation components and control loops including all interlocks and alarm functions

(6) CCWS process heat exchangers and serviced component heat exchangers

(7) CCWS process piping and associated hangers, restraints, and supports

(8) water quality monitoring and control equipment

(9) filters

IV-3.2 Identify System Performance Requirements

Identify system performance requirements for CCWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific CCWS examples beyond those of para. 4.2 of this Part include required heat removal rates from serviced loads, required flow rates to serviced loads, heat exchanger performance, surge tank makeup, and system fluid losses.

IV-3.3 Identify Testable Characteristics That Represent Performance Requirements

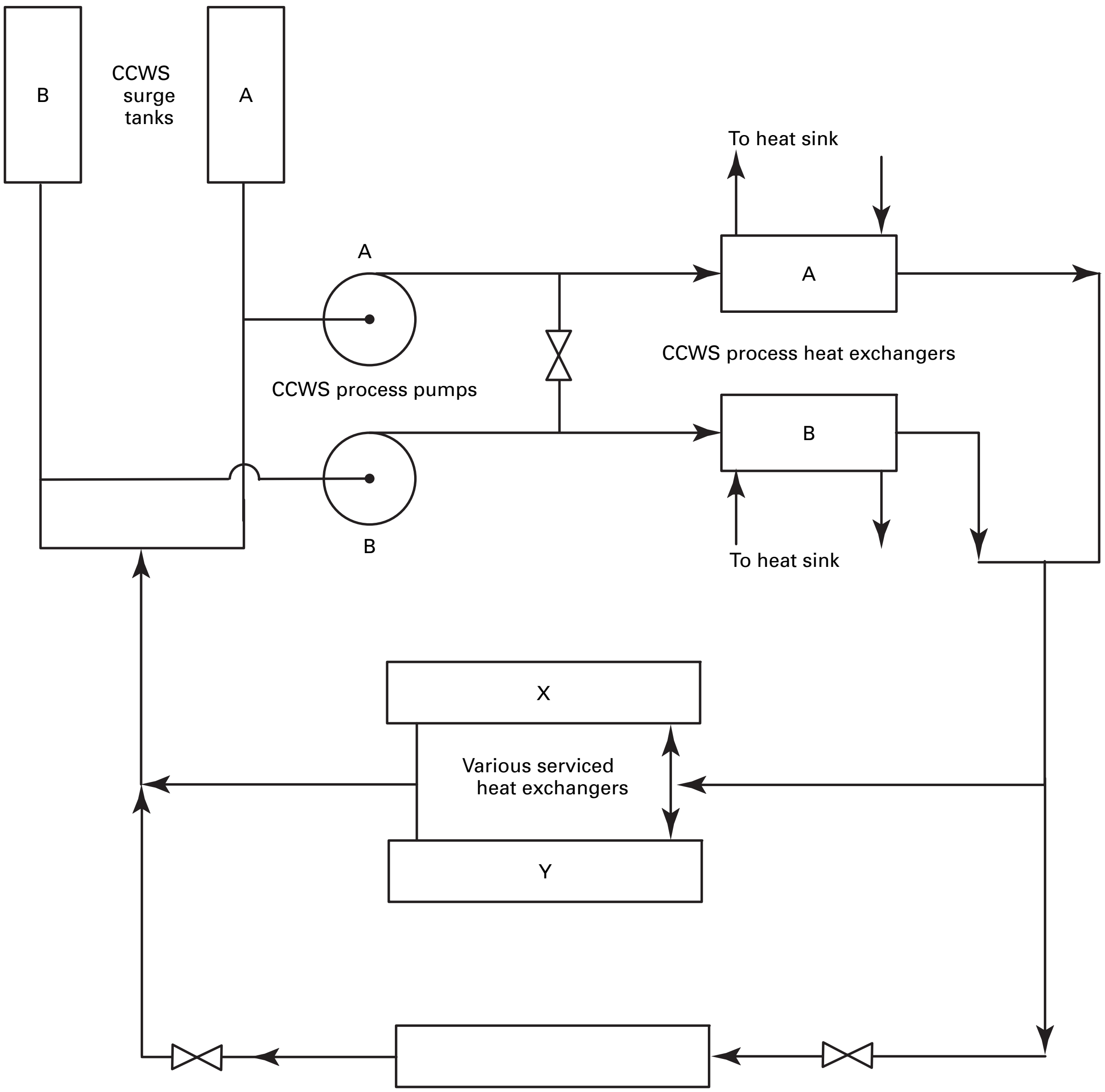
Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical CCWS operation, in addition to those in para. 4.3 of this Part, are

(a) system operating pressures at component elevations where conditions could approach saturation

(b) maintaining system operation during system transients, such as pump trip in parallel pump operation

(c) pressure differential between the CCWS and the heat sink system is in the appropriate direction

Fig. IV-1 CCWS Typical Flow Diagram



IV-3.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. In addition to the examples described in para. 4.3.1 of this Part, additional examples of CCWS system characteristics are flow for serviced and process CCWS heat exchangers, and heat removal for CCWS process heat exchangers.

System characteristics associated with CCWS components are

(a) CCWS Pump and Driver

(1) net positive suction head (NPSH) for pump performance under system conditions with the least NPSH margin

(2) pump total dynamic head (TDH) versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under flow conditions with the least margin to trip

(5) pump driver (as found) power requirements at all flow conditions are within design assumptions for normal and emergency power

(6) pump performance under parallel pump operation

(b) Process Heat Exchangers

(1) amount of heat required to be transferred

(2) system pressure drop through the heat exchanger

(3) heat exchanger outlet temperature

IV-3.3.2 Instrumentation and Control Characteristics. Include CCWS instrumentation and control characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

IV-3.3.3 System Logic Characteristics. Include CCWS logic characteristics as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Specific examples of CCWS logic characteristics are

(a) logic that causes CCWS components to actuate via an ESFAS or ECCS actuation signal

(b) logic that actuates surge tank makeup on low level and pressure control

(c) logic associated with control of manually operated components

IV-3.4 Establish Acceptance Criteria for Testable Characteristics

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

IV-3.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with the requirements of para. IV-3.4 are met.

IV-3.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part. Specific requirements for CCWS, in addition to those in para. 4.5.1 of this Part, are provided below.

IV-3.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

IV-3.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following CCWS-specific requirements.

Verify that the CCWS is in the normal system standby alignment or operation. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated CCWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate CCWS in each required cooling water alignment and pump combination as allowed by plant design. Verify that the required flow is achieved on each branch line or serviced component of CCWS.

Address the following requirements for each applicable operating mode:

(a) Verify that automatic surge tank makeup functions. Demonstrate manual makeup where credited.

(b) Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and accommodated in the system flow balancing. Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Perform the applicable flow testing when such modifications have been made.

Verify CCWS process heat exchangers are tested in accordance with the reference in subpara. 3(a). Using the results of the Part 21 testing and the testing in this Part, perform an evaluation to confirm that the CCWS under least margin operating conditions will meet design basis assumptions. If the evaluation results in required changes to the system, then re-perform the appropriate tests of this Part or Part 21.

IV-3.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

IV-3.5.2 Inservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2 of this Part.

IV-3.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part. In addition, address the following CCWS-specific requirements.

Verify that the CCWS is in the normal system alignment. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated CCWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate CCWS in the accident alignment with each required cooling water branch line and pump combination as allowed by plant design. Test each CCWS train as close as practical to design conditions; however, all heat loads are not required to be in service simultaneously. Verify that the required flow is achieved on each branch line or serviced component of CCWS.

Verify that automatic surge tank makeup functions for each applicable operating mode. Demonstrate manual makeup where credited. Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

IV-3.5.2.2 Inservice Test Interval. Perform inservice tests at intervals in accordance with para. 4.5.2.2 of this Part.

Part 28, Mandatory Appendix V Specific Testing Requirements of Emergency Service Water Systems in LWR Power Plants (Open Cooling Water Systems)

V-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency service water systems (ESWS) perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

V-2 DEFINITIONS

process heat exchanger: a CCWS heat exchanger that rejects heat to the ultimate heat sink.

serviced heat exchanger: a heat exchanger in a supported system that rejects heat to the open cooling water system.

V-3 EMERGENCY SERVICE WATER SYSTEM TEST REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for ESWS.

V-4 ESTABLISH SYSTEM TEST BOUNDARIES

V-4.1 General

Establish the ESWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all ESWS functions described in para. 1.1 of this Part. Include within the test boundary all equipment required to perform the ESWS functions of transferring heat from the supported structures, systems, and components to the ultimate heat sink. This test boundary includes the serviced heat exchangers for the heat sources for ESWS and includes the ultimate heat sink.

(a) Typical Functions. Typical functions include

(1) closed cooling water system heat removal
(2) decay heat removal
(3) containment heat removal
(4) pump and pump driver cooling
(5) diesel generator jacket water cooling

(b) Typical ESWS. Figure IV-1 in Mandatory Appendix IV of this Part shows a simplified ESWS flow diagram and identifies some major components. Components of the typical ESWS may include

(1) ESWS process pumps
(2) control, isolation, throttling, and relief valves
(3) motor controllers, controls, and protective relays
(4) instrumentation components and control loops including all interlocks and alarm functions
(5) serviced heat exchangers
(6) the ultimate heat sink, including heat transfer components such as cooling towers and spray ponds
(7) ESWS process piping and associated hangers, restraints, and supports
(8) water quality monitoring and control equipment
(9) filters and trash screens
(10) alternate suction sources

V-4.2 Identify System Performance Requirements

Identify system performance requirements for ESWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ESWS examples beyond those of para. 4.2 of this Part include required heat removal rates from serviced loads, required flow rates to serviced loads, and heat exchanger performance in addition to heat absorption and rejection requirements of the ultimate heat sink.

V-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm that system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ESWS operation, in addition to those in para. 4.3 of this Part, are

(a) system operating pressures at component elevations where conditions could approach saturation

(b) maintaining system operation during system transients, such as pump trip in parallel pump operation

(c) pressure differential between the ESWS and the heat source systems in the appropriate direction

V-4.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. In addition to the examples described in para. 4.3.1 of this Part, additional examples of an ESWS system characteristics are flow for serviced ESWS heat exchangers, and heat removal for ESWS process heat exchangers.

System characteristics associated with ESWS components are

(a) ESWS Pump and Driver

(1) net positive suction head (NPSH) for pump performance under system conditions with the least NPSH margin

(2) pump total dynamic head (TDH) versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under flow conditions with the least margin to trip

(5) pump driver (as found) power requirements at all flow conditions are within design assumptions for normal and emergency power

(6) pump performance under parallel pump operation

(b) Ultimate Heat Sink

(1) amount of heat required to be transferred

(2) ESWS inlet temperature

(3) available volume

V-4.3.2 Instrumentation and Control Characteristics. Include ESWS instrumentation and control characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

V-4.3.3 System Logic Characteristics. Include ESWS logic characteristics as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Specific ESWS examples of logic are

(a) logic that causes ESWS components to actuate via an ESFAS, ECCS actuation signal, or blackout signal

(b) logic that causes ESWS pumps to start on CCWS start signal

(c) logic associated with control of manually operated components

V-4.4 Establish Acceptance Criteria for Testable Characteristics

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

V-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with the requirements of para. V-4.4 of this Part are met.

V-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

V-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

V-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following ESWS-specific requirements.

Verify that the ESWS is in the normal system standby alignment or operation. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated ESWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate ESWS in each required cooling water alignment and pump combination as allowed by plant design. Test each ESWS train as close as practical to design conditions; however, all heat loads are not required to be in service simultaneously. Verify that the required flow is achieved on each branch line or serviced component of ESWS.

Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and allowed for in the system flow balancing. Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Perform the applicable flow testing when such modifications have been made.

Verify ultimate heat sink heat removal capability. The process described in paras. V-4.2, V-4.3, and V-4.4 will require review of applicable design and analytical information to determine which assumptions require verification by testing to ensure their validity. The resulting testing requirements will vary, depending on the specific design. Note that subpara. 4.5(b) of this Part allows appropriate use of analysis to account for differences between least margin and test conditions. Perform testing to validate testable characteristics of heat rejection systems/components for plants that rely upon man-made or mechanical devices to reject heat to the environment, such as cooling towers, spray ponds, constructed lakes, or dammed lakes.

V-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

V-4.5.2 Inservice Testing. Develop and conduct tests to measure system performance characteristic in accordance with the requirements of para. 4.5.2 of this Part.

V-4.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part.

In addition, address the following ESWS-specific requirements.

Verify that the ESWS is in the normal system alignment. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated ESWS pumps are operating. Verify that system flow balancing for heat transfer requirements is maintained.

Operate ESWS in the accident alignment with each required cooling water branch line and pump combination as allowed by plant design. Test each ESWS train as close as practical to design conditions; however, all heat loads are not required to be in service simultaneously. Verify that the required flow is achieved on each branch line or serviced component of ESWS.

V-4.5.2.2 Inservice Test Interval. Perform inservice tests at intervals in accordance with para. 4.5.2.2 of this Part. An allowable exception to para. 4.5.2.2 of this Part is that verification of ultimate heat sink capability need only be performed following any modification that affects the corresponding performance requirements of para. V-4.2. This exception is allowed provided there is objective evidence that the requirements of para. V-4.2 have been met at least once.

Part 28, Mandatory Appendix VI
Specific Testing Requirements of Instrument Air Systems in LWR Power Plants

VI-1 INTRODUCTION

This Mandatory Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that instrument air (IA) systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Mandatory Appendix.

VI-2 DEFINITIONS

aftercooling: process of removing heat and condensed water from compressor discharge air.

afterfilter: filter located downstream of compressed air dryers, typically to protect downstream equipment from desiccant dust or other particulates.

approach temperature: difference between exit air and cooling medium inlet temperatures.

automatic drain: device that automatically discharges condensate from a moisture separator, typically by action of a float device or timer.

compressed air dryer:

desiccant: compressed air dryer that uses a desiccant to remove moisture.

refrigeration: compressed air dryer that uses mechanical refrigeration to remove moisture.

dew point: temperature at which water vapor begins to condense into liquid.

distribution network: piping and components that supply compressed air to end-use devices.

intercooling: process of cooling air between stages or stage groups of compression.

moisture separator: device that removes liquid from an air stream.

operational capacity: air flow required to maintain satisfactory operation of an instrument air system.

prefilter, coalescing: filter that removes water and oil aerosols by combining the aerosols into larger droplets for easy removal (typically installed ahead of a compressed air dryer).

purge flow: desiccant regeneration air flow.

receiver (air): pressure vessel that contains a volume of air or gas at an elevated pressure, as a reservoir to avoid compressor short cycling, which collects residual condensate and oil droplets and reduces pressure fluctuations in an air system.

special service accumulator: backup air reservoir located near equipment, used to supply compressed air upon loss of the normal source.

VI-3 INSTRUMENT AIR SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for IA systems.

VI-3.1 Establish System Testing Boundaries

Establish the IA test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

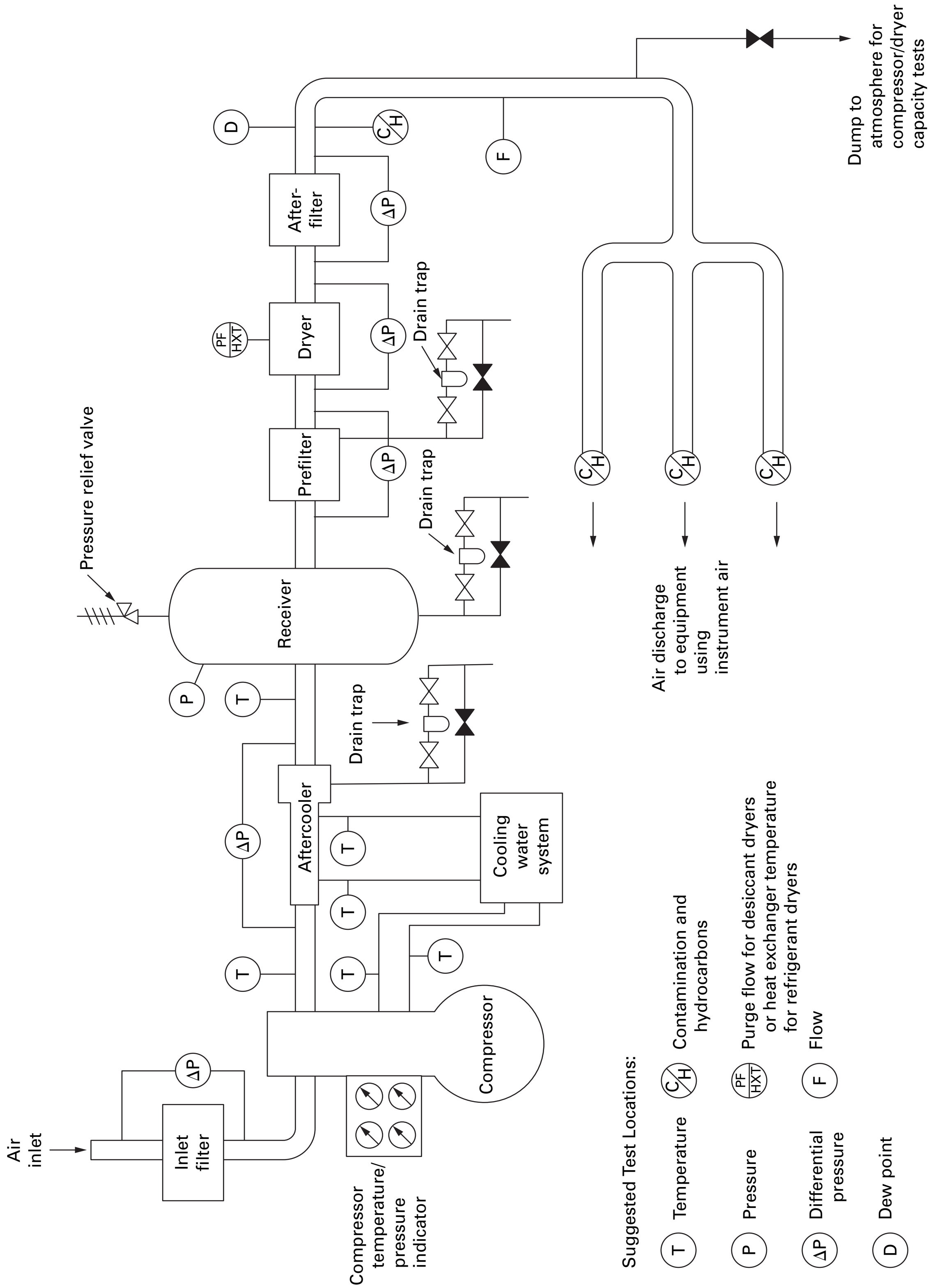
For the purposes of this Mandatory Appendix, the IA system extends from the compressor inlet air filter to, but not including, the end-use device or system of devices (e.g., instrument, equipment prime mover).

Figure VI-1 shows a typical flow diagram of an IA system and identifies major components. For this Mandatory Appendix, an IA system is treated as three subsystems as follows:

(a) Compressor and Receiver. The compressor and receiver subsystem typically consists of compressor inlet filter, compressor, aftercooler, receiver, and associated drain traps and pressure-relief valves. The compressor and receiver subsystem compresses ambient air to increase pressure to system design values and transports it to a receiver where it is stored for system demand surges. This subsystem supplies pressurized, cooled, wet air to the dryer and filter subsystem.

(b) Dryer and Filters. Compressed air is processed by the dryer and filter subsystem of the IA system to remove moisture, oil, and particulate contamination. Typically, this subsystem consists of a coalescing prefilter that removes oil, liquid water, and particulates; an air dryer that removes water vapor; and an afterfilter that removes particulates. The dryer and filter system supplies clean, dry air to the distribution network.

Fig. VI-1 Typical Instrument Air System



(c) Distribution Network. The distribution network consists of the main air headers, branch lines, and accumulators that supply compressed air to end-use devices but does not include pressure regulators. The distribution network must not contaminate the air supply, induce excessive pressure drops, or leak excessively.

VI-3.2 Identify System Performance Requirements

Identify system performance requirements for IA systems within the established test boundaries using the requirements of para. 4.2 of this Part. Specific IA system examples beyond those of para. 4.2 of this Part, include the following:

(a) Compressor and Receiver. The compressor and receiver subsystem supplies pressurized, cooled, wet air to the dryer and filter subsystem at the required demand rate and pressure.

(b) Dryer and Filters. Compressed air is processed by the dryer and filter subsystem to supply clean, dry air to the distribution network at the required dew point, cleanliness, demand rate, and pressure.

(c) Distribution Network. The distribution network supplies compressed air to end-use devices at required capacity and pressure.

VI-3.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical IA system operation, in addition to those in para. 4.3 of this Part, are dew point, cleanliness, demand rate, and pressure that can be used to verify the performance requirement of the end use equipment.

VI-3.3.1 Component Characteristics. Include IA system component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. Specific examples of component characteristics are

(a) Compressor and Receiver Subsystem

(1) inlet filter dP

(2) load and unload pressure setpoint

(3) after cooler and compressor outlet temperature

(4) compressor output flow, by means of a flow rate meter installed downstream of the receiver

(5) pressure drop across the compressor inlet filter

(6) aftercooler dP and approach temperature

(7) compressor outlet pressure

(8) functionality of moisture separator and automatic drains

(b) Dryer and Filter Subsystem

(1) prefilter, receiver, and afterfilter dP

(2) air dryer exit dew point

(3) particulate and oil content

(4) pressure

(5) flow rate

(6) temperature

(c) Distribution Subsystem

(1) pressure at the end use components

(2) initial receiver pressure

(3) pressure decay time

(4) dew point (at line pressure) at the end use components

(5) particulate and oil content at the end use components

VI-3.3.2 Instrumentation and Control (I&C) Characteristics. Include IA system instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

VI-3.3.3 System Logic Characteristics. Include IA system logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. An example of IA system logic is isolation of cross-tied safety and nonsafety systems.

VI-3.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

VI-3.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis (15)

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with para. 4.4 of this Part are met.

VI-3.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

VI-3.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part. In addition, address the following IA system-specific requirements:

(a) Visually inspect air receivers for external damage. If provided with a manhole, inspect internal receiver surfaces for contamination and corrosion.

(b) If applicable, check pneumatic controls using dry air or nitrogen from an external source.

(c) Verify trap and drain valve functionality (receiver, aftercooler separator, and compressor).

(d) Operate the compressor in loaded mode to

(1) verify unload function

(2) verify operation of pressure and temperature trips

(e) Run the dryer through one complete cycle to verify control system and valve operation.

(f) Check for proper refrigerant and air heat exchanger temperature.

VI-3.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applicable to preservice testing that are beyond those stipulated in this Mandatory Appendix for inservice testing. However, the testing of para. VI-4.5.2.1.1 need not be performed as part of the preservice testing.

VI-3.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

VI-3.5.2 Inservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2 of this Part.

VI-3.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part. In addition, address the following IA system-specific requirements:

(15) **VI-3.5.2.1.1 System Material Evaluation.** Conduct the following tests and visual examinations:

(a) Visually examine all internal surfaces accessible through inspection openings for corrosion, erosion, and abnormal corrosion products.

(b) Visually examine external areas of the air receiver for physical damage, leakage from pressure-retaining components, abnormal corrosion products, erosion, corrosion, and loss of integrity of bolted and welded connections.

(c) Nondestructive examinations may be performed as an alternative to the internal visual examination recommendations of subpara. (a) to ensure that vessel wall thickness meets requirements.

(d) Examine prefilter and afterfilter cartridges for contamination levels.

VI-3.5.2.1.2 Compressor and Receiver Subsystem. Achieve stable compressor operation as close as practical to design conditions, and verify that the compressor and receiver subsystem supplies pressurized, cooled air to the dryer and filter subsystem at the required demand rate and pressure. Perform reduced flow tests when the compressor cycles at 4 load/unload cycles/hr. Verify operation of the unloaded system. Verify functionality of recycle and drain valves.

VI-3.5.2.1.3 Dryer and Filter Subsystem. Verify compressed air is processed by the dryer and filter subsystem to supply clean, dry air to the distribution network at the required dew point, cleanliness, demand rate, and pressure.

(a) Conduct the test for at least 8 hr, recording data at 1-hr intervals.

(b) Maintain dryer and filter inlet conditions as close as possible to design conditions including

(1) compressed air at design operating temperature

(2) test pressure at design pressure

(3) compressor outlet flow rate at required capacity of the dryer and filters

(c) During the last 4 hr of the test, check discharge air from the afterfilter at 1-hr intervals for particulate and hydrocarbon contamination.

(d) During the last hour of the test, measure pressure drop across the filters (both pre- and after-filters) and across the air dryer.

(e) When purge air is derived from compressed air, determine purge air usage either by direct flow measurement or by measurement and comparison of outlet flow and inlet flow of the air dryer.

(f) When a desiccant dryer is equipped with an energy management system (moisture load controls), perform a second test to determine the dew point at reduced flow. Measure dew point at 1-hr intervals. For the test

(1) provide two full cycles of the dryer

(2) perform the test between 25% and 50% of design flow rate

(3) perform the test at inlet temperatures that are as low as practical

(4) verify the energy management function acceptance criteria are met

VI-3.5.2.1.4 Distribution Subsystem (15)

(a) In accordance with para. 4.4 of this Part, establish a required minimum operational time for each special service air accumulator and the associated check valves upon loss of the main air system. Use the following sequence for the pressure decay test for each special service air accumulator:

(1) With the accumulator at line operating pressure, isolate the compressed air system supply.

(2) Vent the piping upstream of the accumulator check valves to atmospheric conditions.

(3) Determine the elapsed time for the accumulator to decay to minimum acceptable pressure.

(b) Perform a static pressure decay test of the distribution subsystem to verify operational readiness.

(1) Before performing the test, place in service and align for normal operation all portions of the distribution subsystem.

(2) In accordance with para. 4.4 of this Part, establish acceptance criteria for minimum operational time with compressors tripped. Establish the system pressures at unload and load setpoints.

(3) Verify compressor load and unload setpoints with the compressor loaded and unloaded, with the system at required air usage.

(4) Conduct the test with the compressor isolated and air supplied to the system only from the receivers.

(c) Obtain air samples at the end of each major header in the system and verify acceptable dew point, oil content, and particulate content.

(d) Verify acceptable system pressure, and minimum and maximum cycle pressure and time; measurements should be made at the end of each major header.

VI-3.5.2.2 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. See the following for additional IA system requirements.

(15) **VI-3.5.2.2.1 Compressor and Receiver; Dryer and Filter.** Additional test interval requirements for the compressor, receiver, dryer, and filters are as follows:

(a) Conduct the system material evaluation tests of subparas. VI-3.5.2.1.1(a) through (c) every 3 yr.

(b) Conduct leak testing using the pressure decay test of subpara. VI-3.5.2.1.4(a) for special service accumulators and associated check valves each fuel cycle.

(c) Conduct the inspections of subpara. VI-3.5.2.1.1(d) semiannually and at cartridge change out.

(d) Conduct the tests of subpara. VI-3.5.2.1.3(c) and (d) quarterly.

VI-3.5.2.2.2 Distribution Network. Perform a pressure decay test similar to that described in subpara. VI-3.5.2.1.4(b) if compressor loading indicates an increase in system leakage. Alternatively, if the system has flow measurement capability, monitor flow rates to identify leakage. Analyze and trend the data to determine if compressor degradation or excessive system leakage has developed since the last test. (15)

Part 28, Nonmandatory Appendix A
Industry Guidance

Table A-1 in this Nonmandatory Appendix contains operating experience information associated with light water reactors. The information focuses on events where improved testing might prevent the system from becoming degraded or unable to perform its intended safety functions. Table A-1 summarizes lessons learned from this information, which may be used in developing the test program. More detailed information is also available in the individual regulatory guides (RGs), licensee event reports (LERs), INPO operating experience reports (OEs), and information notices (INs) identified below.

The information in Table A-1 is current through January, 2007. Effort should be taken to utilize current published industry operating experience.

The events summarized in Table A-1 include information on the systems addressed in this Part, in addition to applicable lessons learned on other systems. The events fell into the following ten categories based on proximate cause:

(a) inadequate instrumentation

(b) incorrect pump net positive suction head

(c) pump minimum flow recirculation line problems

(d) pump gas binding problems

(e) incorrect emergency diesel generator electrical loading

(f) inadequate testing frequency

(g) inadequate acceptance criteria

(h) inadequate post-modification testing

(i) inadequate understanding of plant design basis

(j) inadequate preoperational testing

Table A-1 LWR Operating Experience Information

Category	Issue	Source(s) [Note (1)]	Lessons Learned
ECCS instrumentation inadequacies	Incorrect calibration for test conditions	LER 50-397/92-014-01	Test instruments must be calibrated for expected fluid temperature during testing.
	Improper orifice plate flow coefficients	LER 50-344/91-10-01	Use pump header flow measurements to confirm total flow, and use branch line flow measurements for balancing individual injection line flow rates.
	Incorrect orifice plate K-factors and flow transmitter calibration	LER 50-272/90-14; LER 50-244/89-07; LER 50-259/88-07-01	Verify ECCS orifice plate K-factors are correct, and correlate SI system flow transmitter calibration data with the installed flow orifice plates.
	Incorrectly installed and deformed orifice plates	IN 90-65; IN 93-13	Verify beveled edge orifice plates are in the correct orientation (direction). Check for flow and differential pressure induced deformation in orifices used as flow restrictors to limit flow rates.
	Inadequate response time testing of instruments with pressure dampening devices	IN 92-33	Include existing ECCS pressure sensing instrument snubbers in the test configuration when testing instrument response times.
Pump net positive suction head	Insufficient net positive suction head	IN 88-74	Address the effects of potential inadequate NPSH when ECCS pumps are aligned to simultaneously take suction from the discharge of other pumps (piggy-back alignment for PWRs).
	. . .	LER 261-97008	System testing should address all potential (normal and off-normal) system alignments.
	Inadequate surveillance of containment sump	IN 96-10	Three of four sumps contained debris in the bottom below the suction pipe for ECCS systems. Two of the four lines taking suction from the sump were partially blocked.
	Insufficient net positive suction head due to strainer plugging	NRC Bulletin 96-03; RG 1.82 Rev 2; NUREG/CR-6224	Address the effects of potential inadequate suction to the ECCS pumps when aligned to take suction from the containment sump.
	High pump suction pressure	LER 50-327/91-23	Verify maximum ECCS pump suction pressure during piggyback alignment is not excessive. Excessive pressure might lift relief valves and result in loss of coolant outside containment.
	Insufficient suction head conditions on turbine driven pumps	LER 305-05008	System tests to assure acceptable flow and NPSH conditions.
	Inadequate understanding of design basis	IN 98-40	Incorrect understanding of level instrument datum and uncertainties and post-accident pump flow rates may result in inadequate NPSH.
	Impact of NPSH due to addition of gas	IN 2002-18	Addition of gas to water storage tanks can result in inadequate NPSH.
Pump minimum flow recirculation line problems	Deadheading one of two ECCS pumps in systems having a common miniflow recirculation line for both pumps	IN 87-59; LER-305-02001; OEI0478	Consider the potential for pump operation near shutoff head causing deadheading of the weaker pump when pumps operate in parallel alignment.
	Miniflow recirculation line	IN 87-59	Verify ECCS pump miniflow recirculation.
	Flow capacity	Lines have adequate flow capacity for multiple pump operation	. . .

Table A-1 LWR Operating Experience Information (Cont'd)

Category	Issue	Source(s) [Note (1)]	Lessons Learned
Pump gas binding	Accumulator nitrogen binding	IN 89-67	Minimize the effects of nitrogen injection into the RCS when performing full flow RCS accumulator check valve testing by *(a)* testing the valves after refueling rather than during shutdown prior to refueling *(b)* determining if it is appropriate to test the check valves with fuel in the reactor vessel *(c)* reducing accumulator nitrogen pressure or remove the reactor vessel head
	Gas intrusion	IN 88-23 Supplement 3: LERs 50-455/91-12, 455/90-35,213/90-08 INPO SER 2-05	Periodically check the ECCS for gas buildup and vent the systems. This is in addition to any periodic TS required venting of pump casing and discharge piping.
	Air intrusion	IN 2006-21	Inadequate determination of BWST switchover setpoints results in air intrusion to ECCS.
Incorrect emergency diesel generator electrical loading	Emergency diesel generators do not respond to all LOOP and LOCA sequences	IN 93-17	Test EDG starting and loading logic during ECCS testing to verify they will respond correctly to all credible LOOP and LOCA sequences. This includes EDG loading following a LOOP when no postulated accident occurs.
	Emergency diesel generator loading	IN 92-53; IN 91-13; LERs 50-247/89-06, 286/89-10	Consider worst-case conditions (frequency, voltage, electrical power factor, and the environment) when testing EDG load shedding and loading. Verify EDG loading for all ECCS modes.
Inadequate acceptance criteria	. . .	LER 50-325/96-O06	Head losses necessary to account for the difference in the surveillance flow path versus the normal reactor vessel injection flow path were not adequately included in establishing the acceptance criteria.
	Nonconservative acceptance criteria in SR pump surveillance test	IN 97-90	The licensee concentrated on 1ST requirements without ensuring the design requirements were met. Acceptance criteria based on ASME component limits that were less limiting than design basis requirements.
	Surveillances do not test and verify acceptable system resistance.	OE-19856	Surveillance tests do not test and verify acceptable system resistance to ensure the minimum required flow.
	Failure to consider line resistance results in overestimated pump performance	LER 213-95022	Surveillance test acceptance criteria need to address available plant conditions during tests.
	Limited flow test range is inadequate to confirm acceptable performance	OE6615	Testing range must include minimum and maximum flow acceptance criteria.
Inadequate post-modification testing	. . .	IN 96-15	Numerous modifications were made to components that operate from both main control room and remote shutdown panel. Post-modification testing of the components had not included operation from the remote shutdown panel, nor were any periodic surveillance tests performed on the remote shutdown panel.
	Rebuilt pump performance exceeds nonrebuilt pump performance	LER 387-99066; OE-10478	Inadequate post modification testing (all mode of operation) did not reveal design deficiency.

Table A-1 LWR Operating Experience Information (Cont'd)

Category	Issue	Source(s) [Note (1)]	Lessons Learned
Inadequate testing frequency	. . .	IN 93-13;LERs 50-455/ 90-07, 483/91-03	Consider increasing the frequency of SI system total flow testing and branch line flow testing to balance individual injection line flow rates.
Inadequate understanding of plant design basis	Inability to achieve system design basis flow	LER 483-02002	Calculation error in establishing system flow requirements (incorrect basis) resulted in incorrect recirculation flow and unacceptable delivered flow.
	Lack of technical qualifications of personnel	LER 315-99023	The design basis requirements for ESW availability during an accident were inadequately understood.
	Testing configurations violate mode required system/component availability	OE 10153	Test alignments should not violate mode dependent technical specification requirements for system or component operability.
	Inadequate assessment of effect of differential temperatures on safety related pumps	IN 2000-08	Safety related pumps may operate under conditions where either the pumped fluid undergoes a large temperature change or there is a large temperature difference between the pump fluid and cooling water. These situations can lead to pump damage or cause the pump to trip if not adequately incorporated into design.
	Downstream effects of sump debris	GL 2004-02	Sump debris that passes through sump screen may result in blockage or damage to downstream equipment.
Inadequate preoperational testing	Preoperational testing did not address all operating modes	LER 423-96029	Testing did not address recirculation piggy-back alignment resulting in pump runout.

NOTE:
(1) Sources listed in Table A-1 are available through the Nuclear Regulatory Commission at www.nrc.gov/reading-rm/doc-collections/.

Part 28, Nonmandatory Appendix B
Guidance for Testing Certain System Characteristics

B-1 PURPOSE

This Nonmandatory Appendix provides additional guidance on identifying the following system characteristics and verifying that their acceptance criteria are met:

(a) ECCS accumulator discharge flow path resistance
(b) pump total dynamic head (TDH) versus flow
(c) pump discharge flow path overall resistance
(d) balanced branch line resistance

B-2 VERIFYING ECCS ACCUMULATOR DISCHARGE FLOW PATH RESISTANCE IN PWRS

Verification of this system characteristic involves filling each accumulator to a sufficient level and pressure to accomplish the required testing, and individually discharging each into the reactor coolant system (RCS). Use the discharge flow rate and differential pressure between the accumulator and the RCS to calculate discharge flow path resistance. The discharge flow rate may be calculated from the change in accumulator water level versus time measurements. Collect the data once the line isolation valve is fully open. The testing should be performed with sufficient accumulator charge and inventory to allow opening of all in-line check valves to their design basis flow position for sufficient duration to collect the necessary data.

B-3 TYPICAL PROCESS SUBSYSTEM

A typical LWR process subsystem is shown in Fig. B-1 to support the discussions in sections B-4 through B-7. The subsystem is shown with the pumps aligned to distribute to the serviced components by means of four branch lines. The isolated paths represent additional normal or post-accident distribution paths that may be isolated during the test. In addition, the subsystem may have pump minimum recirculation flow paths, which are not shown in this Figure.

B-4 IDENTIFYING AND VERIFYING PUMP TDH VERSUS FLOW ACCEPTANCE CRITERIA

The system hydraulic analysis for a given event or system alignment is based on system delivered flow as a function of boundary conditions specific to that event or alignment. Some analyses use minimum system flow (e.g., small break LOCA) and some use maximum system flow (e.g., inadvertent ECCS actuation or steam generator overfill). The minimum and maximum system flows establish limits on the system pump minimum required and maximum allowable performances. These limits are the acceptance criteria for the system characteristic of pump TDH versus flow.

Distribute the TDH versus flow data points as evenly as possible between minimum and expected flow rates. For critical portions of the pump curve, take additional data points as needed. This data may be obtained using a temporary alignment or dedicated test return line in lieu of the designed system flow path. Acceptance criteria developed in accordance with para. 4.4 of this Part will be minimum and maximum TDH versus flow. Figure B-2 graphically illustrates correction of measured data for instrument accuracy as described in para. 4.4 of this Part. Figure B-3 illustrates the same data points with analysis limits corrected for instrument accuracy as described in para. 4.4 of this Part. Both figures illustrate acceptable test results.

B-5 VERIFYING DISCHARGE FLOW PATH RESISTANCE

The system flow rates used in the system hydraulic analysis are a function of the pump performance, system resistances, and system boundary conditions, including parallel flow paths. The minimum and maximum flow rates used in the event analysis will place limits on the pump discharge flow path resistance and branch line balance. In addition, minimum limits on system resistance may be necessary in order to prevent pump runout (e.g., for PWRs, during long-term core cooling operation when ECCS pumps may be operated in series). These minimum and maximum limits are the acceptance criteria for the system characteristic of pump discharge flow path resistance.

Consider paths that may divert flow from the desired flow path when verifying system resistance. Examples of such paths are pump minimum recirculation paths, reactor coolant pump seal injection paths, unisolated nonessential component cooling water paths, and supply paths to other pumps during series pump operation. Establish minimum resistance limits for these diversion paths to ensure minimum desired flow and to prevent pump runout. Establish maximum limits to ensure that the diversion flow paths support their design function. These minimum and maximum limits form acceptance

Fig. B-1 Typical Branch Line System

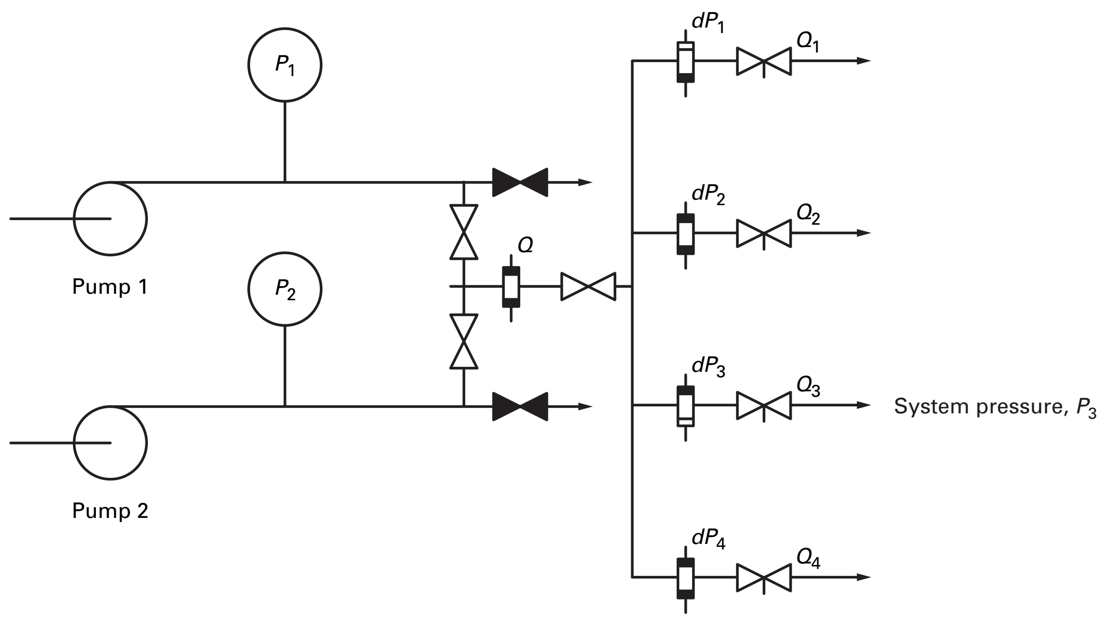


Fig. B-2 Verifying Pump TDH Versus Flow: Correction of Measured Data for Instrument Accuracy (15)

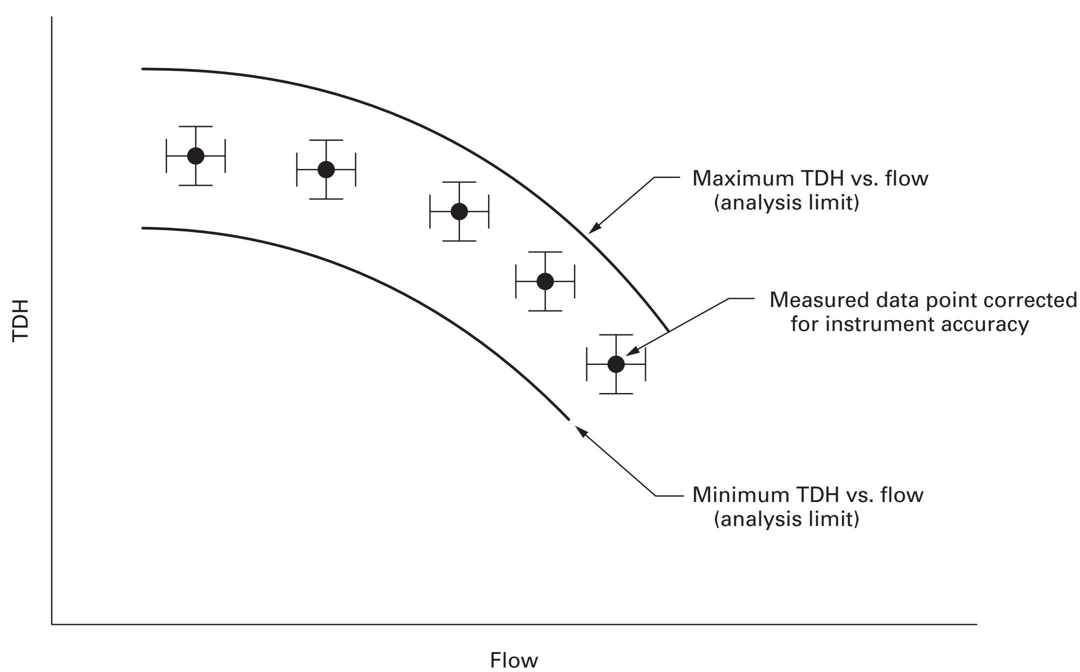
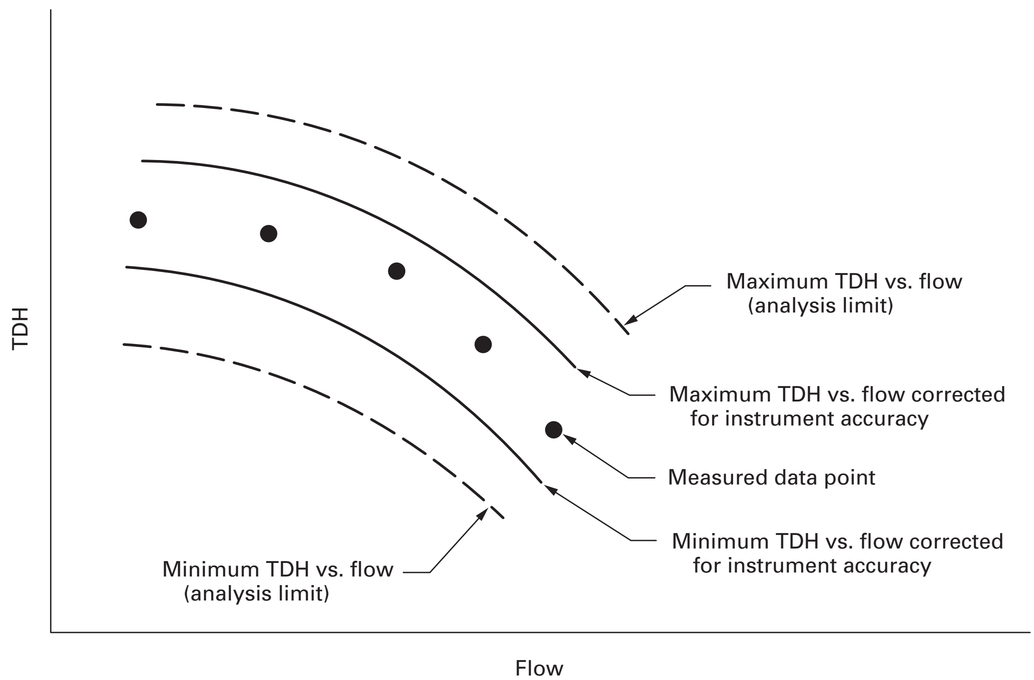


Fig. B-3 Verifying Pump TDH Versus Flow: Correction of Analysis Limits for Instrument Accuracy



criteria for the individual diversion flow path resistances.

Verification of this system characteristic, for the subsystem pictured in Fig. B-1, involves operating either pump while recording pump discharge pressure, P_1 or P_2, as appropriate, total pump flow, Q, and calculating back pressure, P_3. Discharge flow path overall resistance, K_{measured}, is then calculated as follows:

$$K_{\text{measured}} = \frac{P_1 - P_3}{Q^2_{\text{pump1}}} \quad \text{or} \quad \frac{P_2 - P_3}{Q^2_{\text{pump2}}}$$

where

K = discharge flow path resistance
P_1, P_2 = pump discharge pressure
P_3 = back pressure
Q = total pump flow rate

This equation results from an application of Bernoulli's equation between the pump discharge and the point where P_3 is measured. The equation assumes that changes in elevation and velocity heads are negligible in comparison with changes in static pressure head. This assumption is often appropriate to high head pump systems, but should be verified for the specific application. The changes in static pressure head are attributed to unrecoverable friction and form losses. These are expressed as the product of a hydraulic resistance and the square of the flow rate. In general, the hydraulic resistance is a function of Reynolds number and is dependent upon fluid velocity and temperature. If the fluid velocity and temperature at the test conditions vary significantly from design conditions, use of the above equation may not be appropriate without modification.

Typically, the calculated K_{measured} using either Pump 1 or Pump 2 will be about the same; therefore, only one pump need be tested. Compare the noncommon flow paths to confirm this. A stronger pump will have an operating point on a given system that will result in higher pump discharge pressure and correspondingly higher flow such that K_{measured} will be the same as in a test using the weaker pump.

Acceptance criteria developed in accordance with para. 4.4 of this Part will be K_{minimum} and K_{maximum}. Discharge flow path resistance can be plotted as a system curve using the relation

$$H = KQ^2$$

where

H = head
K = discharge flow path resistance
Q = flow

Figure B-4 illustrates correction of measured data for instrument accuracy, while Fig. B-5 illustrates the same measured data with analysis limits corrected for instrument accuracy. Both figures illustrate acceptable test results.

Fig. B-4 Verifying Discharge Piping Overall Resistance: Correction of Measured Data for Instrument Accuracy

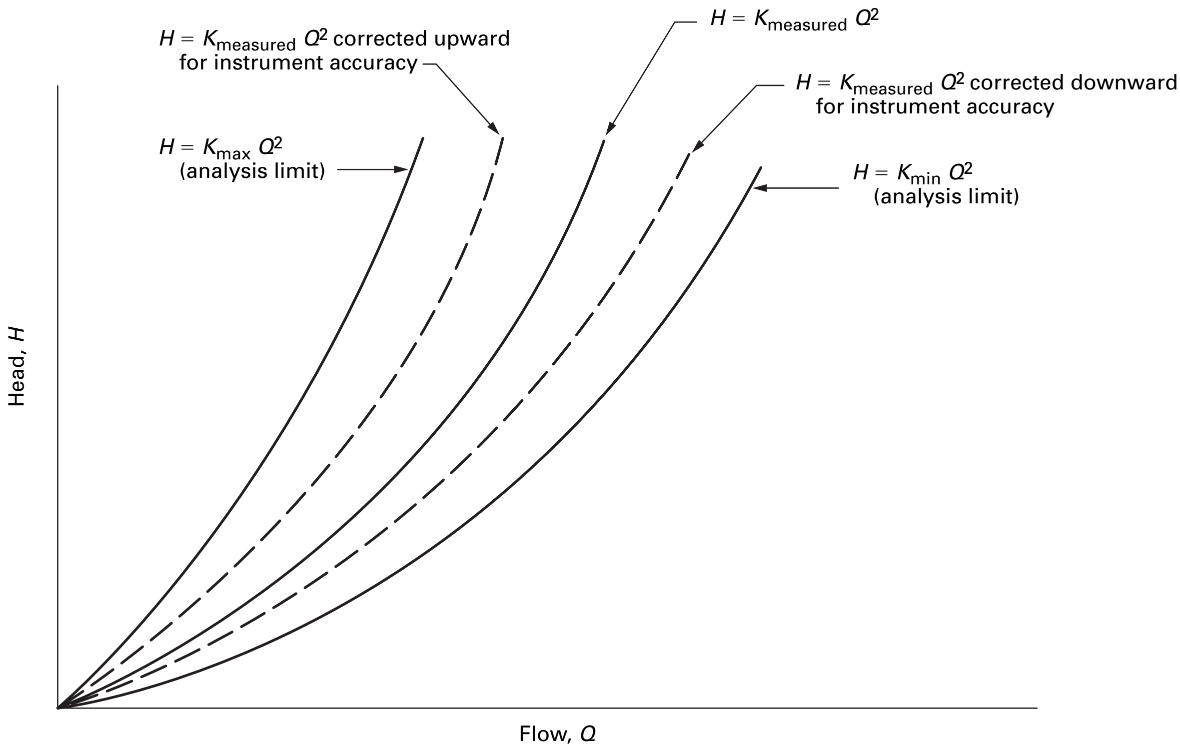
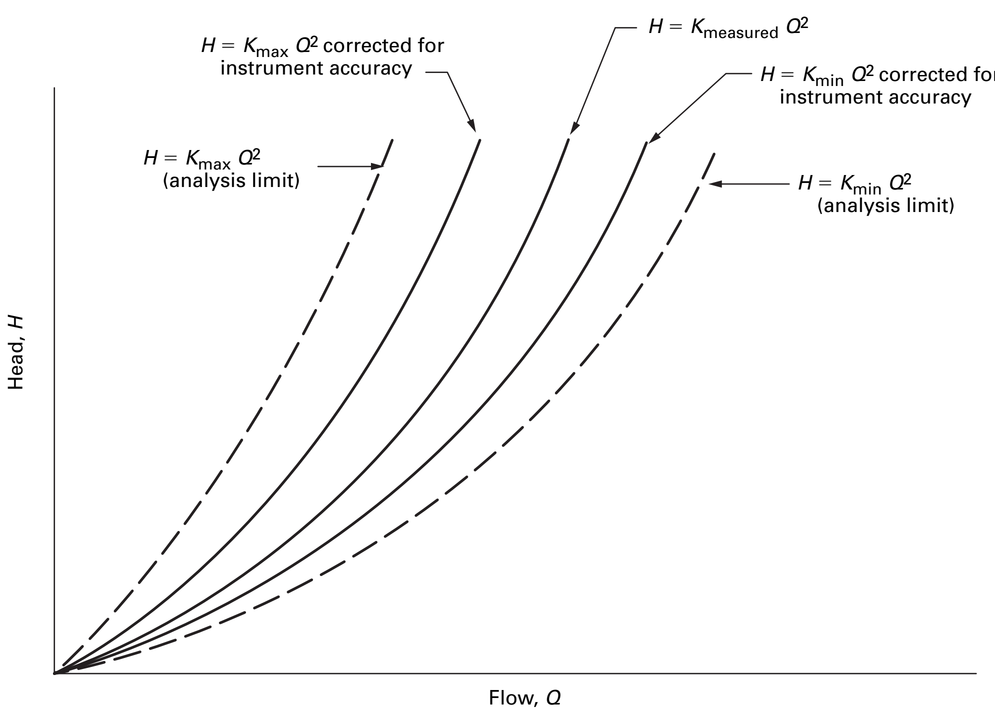


Fig. B-5 Verifying Discharge Piping Overall Resistance: Correction of Analysis Limits for Instrument Accuracy



B-6 VERIFYING BALANCED BRANCH LINE RESISTANCE

Meeting the system performance requirement for delivered flow may require a defined balance between system branch lines. Typically this performance requirement is defined as a relative difference in branch line hydraulic resistance, which can be difficult to measure on individual branch lines. Therefore, balance acceptance criteria can be expressed in terms of an allowable difference in either branch line flow rates or the related parameter of differential pressure (dP) across branch line flow elements.

For the system pictured in Fig. B-1, verifying the system characteristic of balanced branch line resistance requires operating either pump while recording flow element differential pressures dP1, dP2, dP3, and dP4. If the acceptance criterion is a relative flow difference between branch lines, branch line flows are calculated using the relation

$$Q_x = C\sqrt{dP_x}$$

where

C = flow coefficient
dP = flow element differential pressure
Q = calculated pipe flow rate

and the relative flow difference is compared against the acceptance criterion. If the acceptance criterion is relative allowable dP difference, the relative test dP difference is compared against the acceptance criterion. In this instance, meeting the requirements of para. 4.4 of this Part for instrument accuracy would require adding a correction to measured data before comparing to criteria representing analysis limits or subtracting a correction from analysis limits before using these limits as criteria against measured data.

B-7 SYSTEM ADJUSTMENTS

B-7.1 Acceptance Criteria: Section B-4

If the testing described in section B-4 does not meet acceptance criteria, the available options are to

(a) rework or replace the pump and retest.

(b) if possible, refine the analysis on which the acceptance criteria are based such that the measured data meets the revised acceptance criteria. In most cases, the system flow rates are a function of pump performance, system overall resistance, and branch line balance. The acceptable limits of one of these characteristics may be relaxed to gain margin by restricting the acceptable limits of the remaining characteristics.

B-7.2 Acceptance Criteria: Section B-5 or B-6

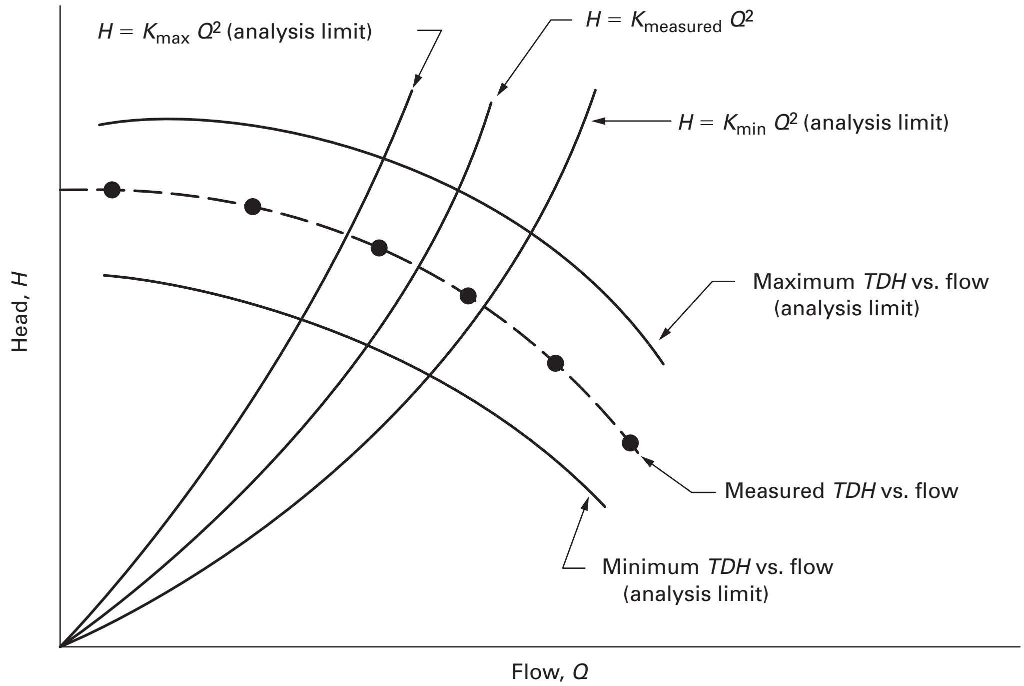
If the testing described in section B-5 or B-6 does not meet acceptance criteria, the available options are to

(a) re-orifice (or adjust throttle valves) and retest the system as required to meet the discharge flow path overall resistance and balanced branch line resistance acceptance criteria. In the system depicted in Fig. B-1, this is accomplished by adjusting the four throttle valves downstream of the flow elements.

(b) refine the analysis per subpara. B-7.1(b).

The final result of implementing sections B-4 through B-7 for a system is graphically depicted in Fig. B-6. Note that this Figure does not include any corrections for instrument accuracy.

Fig. B-6 Measured Subsystem Operating Point and Range of Operating Points Allowed by Analysis Limits



Part 28, Nonmandatory Appendix C
Measurement Accuracy of System Characteristics

C-1 BACKGROUND

Accuracy is defined as the closeness of agreement between the result of a measurement and the true value of the measured parameter. Accuracy statements for instruments are usually given as a percentage of either the upper range value (URV) or the true value. At a single measurement point, there are three sources of error. The average of many readings may be offset from the true value (bias error), the readings may be randomly scattered about the offset (precision error), and one reading may fall well outside the majority of readings (outlier error). It is the combination of the first two types of error that establishes the accuracy of an instrument.

If an instrument is to be used over a range of operation, it is possible to develop a calibration curve that accounts for the directional bias error. Then the calculation of accuracy reduces to the calculation of precision. However, this is not usually done for economic reasons. Instead, most instruments are type-tested to establish a reference accuracy envelope that incorporates precision, directional bias, and bias error range over a specified range of the measured variable. The limits of the envelope are specified as a percentage of the URV or reading. Accuracy envelopes are developed for reference conditions and apply within stated limits on ambient temperature, humidity, flow profile, etc. If the instrument is installed in conditions outside the stated limits of the reference accuracy envelope, additional bias or precision errors may result. These sources of errors are referred to as "influence quantities." In this Nonmandatory Appendix, it is assumed that accuracy envelopes exist for the instruments and that instruments are used within their reference range or adjusted for influence quantities.

System characteristics are variables or attributes that can be verified by direct measurement or data reduction. The values of some system characteristics cannot be directly measured but can be verified by data reduction. Pump total dynamic head and system resistance are examples of characteristics that cannot be directly measured, but can be calculated from other directly measured parameters such as pressure and flow rate. Nonmandatory Appendix B discusses methods for verifying that measured system flow (Q), pump total developed head (TDH), and system resistance (K) meet acceptance criteria, assuming the accuracy of these variables (Q, TDH, or K) are known. The purpose of this Nonmandatory Appendix is to provide a method of determining the accuracy of derived variables (Q, TDH, or K) based on the accuracies of the measured input variables.

C-2 NOMENCLATURE

The following symbols and units are used:

$(Acc)_Y$ = accuracy of variable, Y
D = orifice bore diameter, in.
D_D = discharge pipe inside diameter, in.
D_P = pipe inside diameter, in.
D_S = suction pipe inside diameter, in.
d = total differential operator
g = acceleration of gravity, ft/sec^2
h_L = system head loss, ft
K = orifice flow coefficient
N_R = Reynolds number
P = pressure, psig
P_B = system backpressure, psig
P_D = pump discharge pressure, psig
P_S = pump suction pressure, psig
Q = flow rate, gpm
T = temperature, °F
TDH = pump total developed head, ft
V_B = velocity at system exit,[1] ft/sec
V_D = velocity at pump discharge,[1] ft/sec
V_S = velocity at pump suction,[1] ft/sec
v = specific volume, ft^3/lbm
Z_B = elevation at system exit,[2] ft
Z_D = elevation at pump discharge,[2] ft
Z_S = elevation at pump suction,[2] ft
α = volume expansivity
β = diameter ratio
β_T = isothermal compressibility
ΔH_P = difference in pressure head, ft
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft
ΔP = difference in pressure, psid
μ = dynamic viscosity, lbm/ft-sec
∂ = partial differential operator

[1] This designates the elevation corresponding to the pressure measurement. This is usually the elevation of the pressure gauge or transmitter. However, occasionally, adjustment is made for the elevation head between the pressure tap and the pressure gauge or transmitter in the calibration; in this case, the elevation of the pressure tap should be used.

[2] This designates the velocity in the fluid stream at the location of the pressure tap.

C-3 SENSITIVITY COEFFICIENTS

The reference in subpara. 3(c) of this Part provides the following methodology for determining sensitivity coefficients. This methodology will be applied to various system parameters.

When an equation is used to calculate a quantity (Y) based on measured values of two or more variables (u, v, w, ...), a mathematical entity called the total differential can be used to determine the individual effect of each variable on the final result. If the pertinent variables are independent, then the general functional relationship can be represented as

$$Y = f(u, v, w, \ldots)$$

The total differential is the sum of the partial differentials of the independent variables

$$dY = \frac{\partial Y}{\partial u} du + \frac{\partial Y}{\partial v} dv + \frac{\partial Y}{\partial w} dw + \ldots$$

Dividing the equation for dY by Y yields an equation of the form

$$\frac{dY}{Y} = X_u \frac{\partial u}{u} + X_v \frac{dv}{v} + X_w \frac{dw}{w} + \ldots$$

where

$$X_u = \frac{u}{Y}\frac{\partial Y}{\partial u} = \frac{\frac{\partial Y}{Y}}{\frac{\partial u}{u}}$$

and $\frac{du}{u}$ is the fractional change in u.

If the functional relation is of the form

$$Y = C\, u^l\, v^m\, w^n \ldots$$

then

$$X_u = l$$

$$X_v = m$$

$$X_w = n$$

If each instrument is corrected for the directional bias, or each instrument is operating within its accuracy envelope, the accuracies of the various measuring instruments may be combined by the square-root-sum-squares (SRSS) method to estimate the total measurement accuracy:

$$(Acc)_Y = \pm \left\{ \left[X_u (Acc)_u\right]^2 + \left[X_v (Acc)_v\right]^2 + \left[X_w (Acc)_w\right]^2 + \ldots \right\}^{1/2}$$

C-4 ACCURACY OF DIRECTLY MEASURED VARIABLES

In this Nonmandatory Appendix, pressure, differential pressure, and temperature are treated as fundamental measured fluid properties or system parameters. It is assumed that the measurement accuracy of these parameters is known and can be expressed as a fraction of the measured parameter. This means that terms such as dP/P, $d(\Delta P)/\Delta P$, and dT/T are known. The accuracy of these variables will vary considerably based on such things as

(a) range of instrument
(b) method of processing signal
(c) method of displaying signal
(d) calibration frequency
(e) relation between calibrated (reference) conditions and test conditions (influence quantities)

C-5 ACCURACY OF DERIVED VARIABLES

Fluid properties, such as specific volume, are determined from a correlation (steam tables) that relates the derived property (v) to fundamental measured properties such as pressure and temperature. The accuracy with which specific volume is known is made up of the following three parts:

(a) the accuracy of the correlation between specific volume and pressure and temperature
(b) the accuracy with which fluid temperature is known
(c) the accuracy with which fluid pressure is known

The first accuracy is associated with the correlation, and the latter accuracies are associated with the process variable measurements. The overall accuracy can be written as

$$(Acc)_v = (Acc)_{Correlation} + \left\{ \left[X_T (Acc)_T\right]^2 + \left[X_p (Acc)_p\right]^2 \right\}^{1/2}$$

where

$$X_T = \alpha T$$

$$X_P = -\beta_T P$$

$$\alpha = \frac{1}{v}\frac{\partial v}{\partial T} \quad \text{(volume expansivity)}$$

$$\beta_T = -\frac{1}{v}\frac{\partial v}{\partial P} \quad \text{(isothermal compressibility)}$$

C-6 ACCURACY OF FLOW RATE

This Nonmandatory Appendix assumes that flow rate is measured with an orifice or other device that relates flow rate to a measured pressure change by an equation of the form $Q = SKD^2\sqrt{v\Delta P}$, where S is a constant.

The overall accuracy can be expressed as

$$(Acc)_Q = \pm \left\{ \left[X_K (Acc)_K \right]^2 + \left[X_D (Acc)_D \right]^2 + \left[X_{\Delta P} (Acc)_{\Delta P} \right]^2 + \left[X_v (Acc)_v \right]^2 \right\}^{1/2}$$

where

$$X_D = 2$$

$$X_K = 1$$

$$X_v = \frac{1}{2}$$

$$X_{\Delta P} = \frac{1}{2}$$

The treatment of the above variables is discussed in the following paragraphs.

C-6.1 Flow Coefficient

The flow coefficient can be obtained from either a calibration curve for the specific flow element installation or a correlation for a reference installation of the general type of flow element (e.g., concentric square-edged orifice with flange taps). Deviations from the calibration or reference installation (e.g., proximity to elbow, concentricity requirements, etc.) or application (e.g., diameter ratio limits, pipe size limits, or Reynolds number limits, etc.) require associated bias factors (influence quantities). To emphasize that the influence of installation or application must be considered, a separate bias term will be shown for the flow coefficient.

Since the flow coefficient is a function of the Reynolds number and other parameters, the overall flow coefficient accuracy consists of a calibration or correlation accuracy plus an accuracy associated with the input parameters. Since the Reynolds number depends on specific volume, the flow coefficient accuracy is dependent on the specific volume accuracy. However, in most applications, the effect of input variable (Reynolds number, diameter ratio, etc.) accuracy on overall flow coefficient accuracy is negligible compared with the calibration or correlation accuracy. If this is not the case, the flow coefficient accuracy associated with the accuracy of the input variables must be taken into account.

C-6.2 Orifice Bore Diameter

The orifice bore diameter can be determined from as-built drawings or manufacturing specifications. Generally, the uncertainty in the as-built measurement is less than the specification tolerance; therefore, it is usually reasonable and conservative to use the specification tolerance for computing the bore diameter accuracy.

C-6.3 Orifice Differential Pressure

Orifice differential pressure is directly measured and the directional bias is applied if the instrument is not operating within its accuracy envelope. Therefore, the accuracy of the differential pressure measurement is known.

C-6.4 Specific Volume

This is treated in detail in section C-5.

C-7 ACCURACY OF PUMP TDH

The pump developed head can be calculated from measured variables by the following equation:

$$TDH = 144v\,(P_D - P_S) + (Z_D - Z_S) + \frac{V_D^2 - V_S^2}{2g}$$

This can be written as

$$TDH = \Delta H_P + \Delta H_Z + \Delta H_V$$

where

ΔH_P = difference in pressure head, ft
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft

Assuming the accuracies of the suction and discharge pipe diameters are the same, the overall accuracy in pump TDH can be expressed as

$$(Acc)_{TDH} = \pm \left\{ \begin{aligned} &\left[X_v (Acc)_v \right]^2 + \left[X_{P_D} (Acc)_{P_D} \right]^2 \\ &+ \left[X_{P_S} (Acc)_{P_S} \right]^2 + \left[X_{\Delta Z} (Acc)_{\Delta Z} \right]^2 \\ &+ \left[X_Q (Acc)_Q \right]^2 + \left[X_{D_P} (Acc)_{D_P} \right]^2 \end{aligned} \right\}^{1/2}$$

where

$$X_{D_P} = 4\,\frac{\Delta H_V}{TDH}$$

$$X_{P_D} = \frac{\Delta H_P}{TDH}\left(\frac{P_D}{P_D - P_S}\right)$$

$$X_{P_S} = \frac{\Delta H_P}{TDH}\left(\frac{P_S}{P_D - P_S}\right)$$

$$X_Q = 2\,\frac{\Delta H_V}{TDH}$$

$$X_v = \frac{\Delta H_P}{TDH}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

The following observations are made concerning this expression. First, the sensitivity coefficient for discharge pressure accuracy is much greater than the sensitivity coefficient for suction pressure accuracy. The discharge pressure weighting factor is usually slightly greater than unity, and the suction pressure weighting factor approaches zero. Second, the sensitivity coefficient for the accuracy of the elevation difference between pump discharge and suction pressure instrument locations is the ratio of the elevation difference to the pressure head. This value is usually extremely small compared to the weighting factors for pump suction and discharge pressure measurement. Third, the accuracy of velocity head is broken into two terms: the accuracy with which the flow rate is known and the accuracy with which the suction and discharge pipe inside diameters are known. The weighting factor for both these terms is a multiple of the velocity head-to-pressure head ratio. The last term is usually very small relative to other terms. For most applications, the accuracy of the pump TDH measurement will be dictated by the accuracy of the discharge pressure measurement.

C-8 ACCURACY OF SYSTEM RESISTANCE

The safety injection system pump discharge head loss can be calculated from the measured system parameters by the following equation:

$$h_L = 144v\,(P_D - P_B) + (Z_D - Z_B) + \frac{V_D^2 - V_B^2}{2g}$$

$$h_L = \Delta H_P + \Delta H_Z + \Delta H_V$$

where

ΔH_P = difference in pressure head, ft
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft

The safety injection system resistance is defined as

$$K = \frac{h_L}{Q_{SI}^2}$$

Each of the above terms is independent and can be combined by the SRSS method to estimate the total measurement accuracy.

$$(Acc)_K = \pm\left\{\begin{aligned}&\left[X_v\,(Acc)_v\right]^2 + \left[X_{P_D}\,(Acc)_{P_D}\right]^2\\&+\left[X_{P_B}\,(Acc)_{P_B}\right]^2 + \left[X_{\Delta Z}\,(Acc)_{\Delta Z}\right]^2\\&+\left[X_Q\,(Acc)_Q\right]^2 + \left[X_{D_P}\,(Acc)_{D_P}\right]^2\end{aligned}\right\}^{1/2}$$

where

$$X_{D_P} = 4\,\frac{\Delta H_V}{h_L}$$

$$X_{P_B} = \frac{\Delta H_P}{h_L}\left(\frac{P_B}{P_D - P_B}\right)$$

$$X_{P_D} = \frac{\Delta H_P}{h_L}\left(\frac{P_D}{P_D - P_B}\right)$$

$$X_Q = 2\left(\frac{\Delta H_V}{h_L} - 1\right)$$

$$X_v = \frac{\Delta H_P}{h_L}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{h_L}$$

It is noted that system head loss is composed of both form losses and frictional losses. In general, each of these losses depends on Reynolds number and other variables. Therefore, attention must be paid to differences between test conditions and operating conditions when developing and applying test criteria for system resistances.

C-9 EXAMPLE EVALUATION OF PUMP TDH ACCURACY

This section provides a sample evaluation of the accuracy of the measurements of pump performance. The purpose is to illustrate use of the methodology provided in this Nonmandatory Appendix.

Table C-1 Recorded Test Data

Parameter	Value (U.S. Customary Units)	Value (SI Units)
P_D	745 psia	5 136.6 kPa
P_S	36 psia	248.2 kPa
Q	1,580 gal/min	0.09969 m^3/s
Z_D	121 ft	36.88 m
Z_S	118 ft	35.97 m
D_S	7.981 in.	20.27 cm
D_D	5.761 in.	14.63 cm
T	70°F	21.1°C

Table C-2 Calculated Pump Head

Parameter	Value, ft (U.S. Customary Units)	Value, m (SI Units)
ΔH_P	1,633.5	497.9
ΔH_Z	3	0.91
ΔH_v	4.3	1.31
TDH	1,640.8	500.1

C-9.1 Evaluation of Accuracy of Measurement of Pump Performance

Section C-7 provides the following equation for determining the accuracy of pump TDH.

$$(Acc)_{TDH} = \pm \left\{ \begin{aligned} & \left[X_v (Acc)_v\right]^2 + \left[X_{P_D} (Acc)_{P_D}\right]^2 \\ & + \left[X_{P_S} (Acc)_{P_S}\right]^2 + \left[X_{\Delta Z} (Acc)_{\Delta Z}\right]^2 \\ & + \left[X_Q (Acc)_Q\right]^2 + \left[X_{D_P} (Acc)_{D_P}\right]^2 \end{aligned} \right\}^{1/2}$$

There are two aspects of evaluating the uncertainty in pump TDH. First, the sensitivity coefficients (X_I) must be determined for each parameter that is used to calculate the TDH. Second, the accuracy, $(Acc)_I$, of each individual parameter must be determined.

C-9.1.1 Evaluation of Pump TDH Sensitivity Coefficients. The data in Table C-1 was recorded during a test.

The specific volume at the test temperature and the pump discharge pressure is 0.016 ft^3/lbm (0.0009989 m^3/kg). The specific volume, along with the information in Table C-1, can be used to calculate the parameters in Table C-2.

Table C-3 Sensitivity Coefficients for Pump TDH

Parameter	Sensitivity Coefficient	Value
Specific volume	Xv	0.9956
Discharge pressure	XPD	1.0251
Suction pressure	XPS	0.0295
Elevation difference	XΔZ	0.0018
Flow rate	XQ	0.0052
Pipe diameter	XD	0.0104

These parameters can be used to determine the sensitivity coefficients by means of the following formulas provided in section C-7:

$$X_{D_P} = 4 \frac{\Delta H_V}{TDH}$$

$$X_{P_D} = \frac{\Delta H_P}{TDH} \left(\frac{P_D}{P_D - P_S} \right)$$

$$X_{P_S} = \frac{\Delta H_P}{TDH} \left(\frac{P_S}{P_D - P_S} \right)$$

$$X_Q = 2 \frac{\Delta H_V}{TDH}$$

$$X_v = \frac{\Delta H_P}{TDH}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

The sensitivity coefficients calculated in this manner are summarized in Table C-3.

It is seen that the two predominant factors in evaluating pump TDH are specific volume and discharge pressure. For the time being, in anticipation of the fact that $(Acc)_v << (Acc)_P$, ignore the effect of specific volume on overall accuracy. If it is then assumed the discharge pressure is known to an accuracy of 1% and the remaining parameters are known to an accuracy of 10%, the overall accuracy of the measurement is 1.1%. For this reason, conservative, but reasonable, accuracies for suction pressure, pressure gauge elevation difference, flow rate, and pipe diameter can usually be used to determine the overall accuracy of the pump TDH measurement.

C-9.1.2 Evaluation of Pump TDH Component Accuracies

C-9.1.2.1 Specific Volume. Since the sensitivity coefficient for specific volume is approximately the same as that for discharge pressure, the accuracy of the specific volume will be examined in detail. (15)

The total uncertainty in specific volume is made up of the following three parts:

(a) the uncertainty resulting from the accuracy of the correlation as a function of pressure and temperature

(b) the uncertainty in fluid temperature
(c) the uncertainty in fluid pressure

The first uncertainty is associated with the correlation, and the latter uncertainties are associated with the process variable measurements.

$$(Acc)_v = \pm(Acc)_{\text{Correlation}} \pm \left\{\left[X_T\,(Acc)_T\right]^2 + \left[X_p\,(Acc)_p\right]^2\right\}^{1/2}$$

where

$$X_P = -\beta_T P$$

$$X_T = \alpha T$$

$$\alpha = \frac{1}{v}\frac{\partial v}{\partial T} \qquad \text{(volume expansivity)}$$

$$\beta_T = -\frac{1}{v}\frac{\partial v}{\partial P} \quad \text{(isothermal compressibility)}$$

The uncertainty in the specific volume correlation as a function of pressure and temperature was obtained from the reference in subpara. 3(b) of this Part. Over the range 0 psia to 1,450 psia (0 bar to 100 bar) and 32°F to 212°F (0°C to 100°C) the uncertainty in the correlation is $d_v/v = 0.0004$ per Table 2 of Appendix 3 of that document. The values of specific volume are given as a function of pressure and temperature in the reference in subpara. 3(b) of this Part (within the ranges 500 psia to 1,500 psia and 40°F to 120°F). These can be used to calculate the values of partial derivatives of specific volume with respect to pressure and temperature as follows:

$$\frac{\partial v}{\partial P} = -5 \times 10^{-8}\ \frac{\text{ft}^3/\text{lb}_\text{m}}{\text{psi}} \left(-4.5 \times 10^{-10}\ \frac{\text{m}^3/\text{kg}}{\text{kPa}}\right)$$

$$\frac{\partial v}{\partial T} \leq -2.375 \times 10^{-6}\ \frac{\text{ft}^3/\text{lb}_\text{m}}{°\text{F}} \left(\leq 2.7 \times 10^{-7}\ \frac{\text{m}^3/\text{kg}}{°\text{C}}\right)$$

A specific volume of 0.016 $\text{ft}^3/\text{lb}_\text{m}$ (0.0009989 m^3/kg) results in

$$\beta_T = -\frac{1}{v}\frac{\partial v}{\partial P} = 3.121 \times 10^{-6}\ \frac{\text{in.}^2}{\text{lb}} \left[4.5 \times 10^{-7}\ (\text{kPa})^{-1}\right]$$

$$\alpha = \frac{1}{v}\frac{\partial v}{\partial T} = 1.483 \times 10^{-4}\ (°\text{F})^{-1} \left[2.7 \times 10^{-4}\ (°\text{C})^{-1}\right]$$

A temperature of 70°F (21.1°C) and a pressure of 745 psia (5 137 kPa) results in

$$X_T = \alpha T = 0.0104\ (0.0057)$$

$$X_P = -\beta_T P = -0.0023\ (-0.0023)$$

It is noted that the sensitivity coefficient for temperature changes upon conversion to metric units since the temperature in degrees Fahrenheit is not proportional to the temperature in degrees Celsius.

The pressure gauge used to measure the pump discharge pressure had a range of 0 psia to 3,000 psia (0 kPa to 21 000 kPa) and an accuracy of 1% of instrument range. The fluid temperature measurement had a range of 50°F to 200°F (10°C to 95°C) and an accuracy of 2% of instrument range.

$$(Acc)_P = \frac{dP}{P} = \frac{0.01\ (3{,}000\ \text{psi})}{745\ \text{psia}} = 0.04$$
$$\left[= \frac{0.01\ (21{,}000\ \text{kPa})}{5{,}137\ \text{kPa}} = 0.04\right]$$

$$(Acc)_T = \frac{dT}{T} = \frac{0.02\ (150°\text{F})}{70°\text{F}} = 0.04 \left[= \frac{0.02\ (85°\text{C})}{21.1°\text{C}} = 0.08\right]$$

$$(Acc)_v = \pm(Acc)_{\text{Correlation}} \pm \left\{\left[X_T\,(Acc)_T\right]^2 + \left[X_p\,(Acc)_p\right]^2\right\}^{1/2}$$

$$\begin{aligned}(Acc)_v &= \pm 0.0004 \pm \left\{\left[0.0104(0.04)\right]^2 + \left[0.0023(0.04)\right]^2\right\}^{1/2} \\ &= 0.0008\end{aligned}$$

It is noted that the accuracy associated with the inputs decreases the overall accuracy by 100%. This is largely due to the fact that the correlation is very accurate.

C-9.1.2.2 Discharge Pressure. As determined above, the discharge pressure measurement had an accuracy of 4%.

C-9.1.2.3 Suction Pressure. The suction pressure instrument had a range of 0 psia to 100 psia (0 kPa to 700 kPa) and had an accuracy of 1.0% of instrument span.

$$(Acc)_P = \frac{dP_S}{P_S} = \frac{0.01\ (100\ \text{psi})}{36\ \text{psi}} = 0.028$$
$$\left[= \frac{0.01\ (700\ \text{kPa})}{248\ \text{kPa}} = 0.028\right]$$

C-9.1.2.4 Elevation Difference. The elevation difference measure is known to within 3 in. (7.6 cm). Therefore, the accuracy is

$$(Acc)_{\Delta Z} = (3\ \text{in.})(1\ \text{ft}/12\ \text{in.})/(3\ \text{ft}) = 0.08$$

C-9.1.2.5 Flow Rate. As previously mentioned, the impact of flow measurement accuracy on pump TDH measurement accuracy is very small. Therefore, a rough estimate of the accuracy is sufficient.

$$\begin{aligned}(Acc)_Q = \pm \Big\{&\left[X_K\,(Acc)_K\right]^2 + \left[X_D\,(Acc)_D\right]^2 \\ &+ \left[X_{\Delta P}\,(Acc)_{\Delta P}\right]^2 + \left[X_v\,(Acc)_v\right]^2\Big\}^{1/2}\end{aligned}$$

where

$$X_D = 2$$

$$X_K = 1$$

$$X_v = \frac{1}{2}$$

$$X_{\Delta P} = \frac{1}{2}$$

$$(Acc)_K = (\text{Bias})_{\text{Influence}} \pm (Acc)_{\text{Correlation}} \pm (Acc)_{\text{Inputs}}$$

The flow measurement accuracy is typically dominated by the accuracies with which the flow coefficient and differential pressure are known. The correlation accuracy for the flow coefficient is 1%, and a bias of 0.5% is applied, since the orifice is installed less than the required number of pipe lengths downstream of an elbow. The accuracy associated with uncertainties in Reynolds number and diameter ratio are negligible. Therefore, the accuracy of the flow coefficient is 1.5%. The differential pressure is known within 2% of the measured value. The contributions due to uncertainties in bore diameter and specific volume are negligible. The overall accuracy in flow rate is estimated as

$$(Acc)_Q = \pm \left\{ [(0.015)]^2 + [0.5(0.02)]^2 \right\}^{1/2} = 0.018$$

Therefore, the flow measurement accuracy is dictated by the accuracy with which the flow coefficient is known.

C-9.1.2.6 Pipe Diameter. The pipe diameter is known to within 0.010 in. out of 5.761 in. Therefore,

$$(Acc)_{D_P} = \frac{dD_P}{D_P} = \frac{0.01 \text{ in.}}{5.761 \text{ in.}} = 0.0017$$

C-9.2 Results

$$(Acc)_{TDH} = \pm \left\{ \begin{array}{l} \left[X_v (Acc)_v\right]^2 + \left[X_{P_D} (Acc)_{P_D}\right]^2 \\ + \left[X_{P_S} (Acc)_{P_S}\right]^2 + \left[X_{\Delta Z} (Acc)_{\Delta Z}\right]^2 \\ + \left[X_Q (Acc)_Q\right]^2 + \left[X_{D_P} (Acc)_{D_P}\right]^2 \end{array} \right\}^{1/2}$$

The sensitivity coefficients and accuracies are summarized in Table C-4.

It is seen that the accuracy of the pump TDH is dominated by the accuracy of the discharge pressure.

Table C-4 Pump TDH Overall Accuracy Calculation

Parameter	Sensitivity Coefficient, X_1	Accuracy, $(Acc)_I$	$[X_I(Acc)_I]^2$
V	0.9956	0.0008	6.344×10^{-7}
P_D	1.0251	0.04	1.681×10^{-3}
P_S	0.0295	0.028	6.823×10^{-7}
$Z_D - Z_S$	0.0018	0.08	2.074×10^{-8}
Q	0.0052	0.018	8.761×10^{-9}
D_p	0.0104	0.0017	3.126×10^{-10}
$\Sigma\ [X_I(Acc)_I]^2$	. . .	. . .	1.683×10^{-3}
Overall accuracy $\{\Sigma\ [X_I(Acc)_I]^2\}^{1/2}$	. . .	. . .	0.0410

Part 29
Alternative Treatment Requirements for RISC-3 Pumps and Valves

1 INTRODUCTION

1.1 Scope

This Part provides alternative treatments for examination and testing of pumps and valves that have been classified as Risk-Informed Safety Class 3 (RISC-3) in accordance with 10CFR 50.69 1. This Part contains requirements for the elements of a combined examination and testing program that will provide reasonable confidence that RISC-3 components will remain capable of performing their intended functions under design basis conditions until the next scheduled examination or test.

1.2 Exclusions Identification

Exclusions identification of alternative treatments for pump and valve passive functions to maintain component pressure boundary are excluded from this Part.

1.3 Owner's Responsibility

(a) Scope Identification. The Owner shall identify which safety-related pumps and valves are Low Safety Significant (RISC-3) that are to be removed from the scope of the ASME OM inservice testing (IST) program.

(b) Industrial Practices. The Owner shall maintain controls for industrial practices that are used to implement alternative treatments for RISC-3 pumps and valves.

2 DEFINITIONS

examination: observing, visual monitoring, or measuring to determine conformance to Owner-specified requirements.

industrial practices: treatments commonly used within the industry that ensure reliable performance of components. Examples of industrial practices include, but are not limited to, a preventive maintenance program, work control processes, post-maintenance testing, and operating/industry experience evaluation program.

reasonable assurance: a justifiable level of confidence used to satisfy regulatory requirements, that is based upon objective or measurable evidence.

reasonable confidence: a level of confidence based on engineering judgment supported by facts, actions, knowledge, experience, and/or observations. Reasonable confidence is a lower level of confidence than reasonable assurance.

special treatment requirements: prescriptive regulatory requirements as to how Owners are to treat components, especially those defined as safety-related.

testing: the act of verifying that component performance satisfies expected results or parameters.

treatments: activities, processes, and/or controls that are performed or used in the design, installation, maintenance, and operation of components.

3 GENERAL PROGRAMMATIC REQUIREMENTS FOR RISC-3 PUMPS AND VALVES

3.1 Component Scope

The Owner shall identify which safety-related pumps and valves are Low Safety Significant (RISC-3) that are to be removed from the scope of the ASME OM inservice testing (IST) program.

3.2 Reasonable Confidence

The Owner shall document the RISC-3 pumps' and valves' reasonable confidence basis that supports the performance of active low safety significant functions.

3.3 Industrial Practices

(a) The Owner shall select the processes that ensure RISC-3 pumps and valves continue to reliably perform their functions. Existing industrial practices implemented by the Owner should be considered when establishing these processes.

(b) Processes designed to provide reasonable assurance (i.e., special treatment requirements) are not required for RISC-3 pumps and valves. However, Owners may elect to use certain special treatment processes at their discretion.

3.4 Functional Requirements

(a) Functional requirements for RISC-3 pumps and valves shall be maintained.

(b) Functional testing acceptance criteria for RISC-3 pumps and valves shall be based on functional requirements applicable to the active intended low safety significant functions.

(c) Postmaintenance testing shall be performed to support the Owner's determination that the pump or valve remains capable of performing the intended safety functions.

4 ALTERNATIVE TREATMENT FOR REASONABLE CONFIDENCE OF RISC-3 PUMP AND VALVE PERFORMANCE

4.1 Alternative Treatment Goals

Goals are provided in the following steps due to the variety of methods that can be employed by Owners to establish alternative treatments to maintain reasonable confidence in the performance of RISC-3 pumps and valves.

(a) Alternative treatments for RISC-3 pumps and valves shall provide information to ascertain, with reasonable confidence, that the component is capable of performing its active low safety significant functions.

(b) Alternative treatments shall provide insight to detect and correct failures of RISC-3 pumps and valves.

(c) Alternative treatments shall ensure no significant increase in pump and valve failure rates. (Reference para. 6.3.)

4.2 Alternative Treatment Considerations

(a) Programs/processes already in use by the Owner to maintain reliability of industrial equipment shall be considered when selecting alternative treatments.

(b) The Owner shall establish reasonable confidence for pump and valve active safety functions considering a combination of examination and/or testing activities.

(c) Level of confidence in pump and valve performance depends on the frequency and amount of information provided by the examination or testing activity.

(d) The Owner shall determine the rigor of examination and testing necessary to establish an acceptable level of reasonable confidence.

(e) A greater amount of treatment shall be applied when the maintenance and operational history reflects a greater incidence of degraded conditions for the RISC-3 component or component group.

(f) A lesser amount of treatment may be applied if the RISC-3 pump or valve is normally in its required safety position.

(g) Alternative treatments shall be reviewed for adjustment if adverse component performance trends are noted.

(h) Industry guidance, industry operating experience, and site-specific experience shall be used to determine examination and testing frequencies.

(i) Examination and testing strategies shall be documented to state the basis for reasonable confidence associated with the selected industrial practices.

(j) Changes to alternative treatments shall be controlled by the industrial practices used for alternative treatment activities.

4.3 Alternative Treatment Selection for Reasonable Confidence

(a) The Owner shall identify examination and/or testing activities to provide reasonable confidence that the RISC-3 pumps and valves will continue to perform their intended function.

(b) The degree of reasonable confidence required shall influence the extent of treatment activities selected. For example, visual examinations performed more frequently than diagnostic examinations may provide the required degree of reasonable confidence.

(c) The Owner shall consider performing some or all of the following examinations:

(1) visual examinations
(2) operator rounds
(3) system engineer walkdowns
(4) control board indications
(5) system parameter trending
(6) disassembly and examination
(7) diagnostic examinations

(d) Performance demands associated with operational evolutions (e.g., train rotation or refueling-related operations) that cause the pump or valve to perform its intended safety function may suffice as a testing activity.

(e) The Owner shall consider performing some or all of the following tests:

(1) post-maintenance testing
(2) performance testing
(3) stroke or actuation demands
(4) diagnostic testing
(5) surveillance testing

5 CORRECTIVE ACTION

(a) The Owner shall maintain a corrective action program that identifies and corrects material deficiencies of RISC-3 pumps and valves.

(b) If RISC-3 component failures exceed expected thresholds, an extent of this condition shall be assessed with respect to other plant components. For significant conditions adverse to quality, measures shall be taken to provide reasonable confidence that the cause of the condition is determined and that corrective action is taken to prevent recurrence.

(1) The Owner shall consider measures to prevent recurrence of RISC-3 failures including changes to the alternative treatment identified for the affected pumps and valves.

(2) Reinstitution of certain special treatment requirements shall be considered to prevent RISC-3 failures, as deemed appropriate by the Owner.

6 FEEDBACK AND TREATMENT ADJUSTMENT

(a) On a periodic basis (not to exceed 10 yr), performance information from the alternative treatment examination and testing activities and the corrective action program shall be analyzed for performance trend changes.

(b) An alternative treatment review shall be performed for any RISC-3 pump and valve whose performance indicates an adverse trend.

(c) The change in component performance shall be compared to the insights used to categorize safety-related pumps and valves as Low Safety Significant (RISC-3) that have been removed from the scope of the ASME OM in-service testing (IST) program.

7 RECORDS

(a) The Owner shall document the reasonable confidence basis for the alternative treatments selected for RISC-3 pumps and valves.

(b) The records of examination and testing performance and results shall be documented in accordance with the Owner's established industrial practices (e.g., preventive maintenance tasks, work orders, etc.).

(c) Current reasonable confidence basis records shall be retained and shall comply with the Owner's established industrial practices.

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DIVISION 3: OM GUIDES

CONTENTS

Part 5
Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants

1 PURPOSE AND SCOPE

1.1 Purpose

This Part outlines an inservice monitoring program for detecting significant loss of axial preload at the core support barrel's upper support flange in pressurized water reactors.

1.2 Scope

This Part provides guidance for inservice monitoring of core support barrel axial preload in PWR power plants and recommends monitoring methods, intervals, parameters to be measured and evaluated, acceptance criteria, and records requirements.

1.3 Application

This Part addresses the use of ex-core neutron detector signals to infer the condition of axial preload.

1.4 Definitions

(a) The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

axial preload: the axial clamping force at the core support barrel upper flange that prevents vertical or lateral motion of core support barrel at the location.

cantilever mode of vibration: the fundamental vibration mode of a simple beam with one end clamped and one end free.

core support barrel: the cylindrical structure located inside and concentric with the reactor pressure vessel that has the primary structural function of supporting the reactor core.

core support barrel frequency: the natural (resonant) frequency of the dominant beam mode response of the core support barrel vibration.

ex-core neutron detectors: neutron detectors located outside of the pressure vessel and at the same elevation as the core and used to monitor neutron flux as an indication of reactor power.

mechanical snubbers: dynamic restraint devices in which load is transmitted entirely through mechanical components.

neutron noise: fluctuations in the detected neutron signal from a reactor operating at steady state.

(b) The following terms pertaining to random data analysis are defined in ANSI S2.10-1971, Methods for Analysis and Presentation of Shock and Vibration Data:

(1) autopower spectral density function, APSD (also power spectral density)

(2) cross-power spectral density function, CPSD (also cross-spectral density)

(3) coherence function, COH

(4) root mean square, rms

(c) The following normalized spectral densities are referred to in this Part:

(1) normalized power structural density, NPSD

(2) normalized root mean square, nrms

(3) normalized cross-power spectral density, NCPSD

The normalized functions are defined in Nonmandatory Appendix B of this Part.

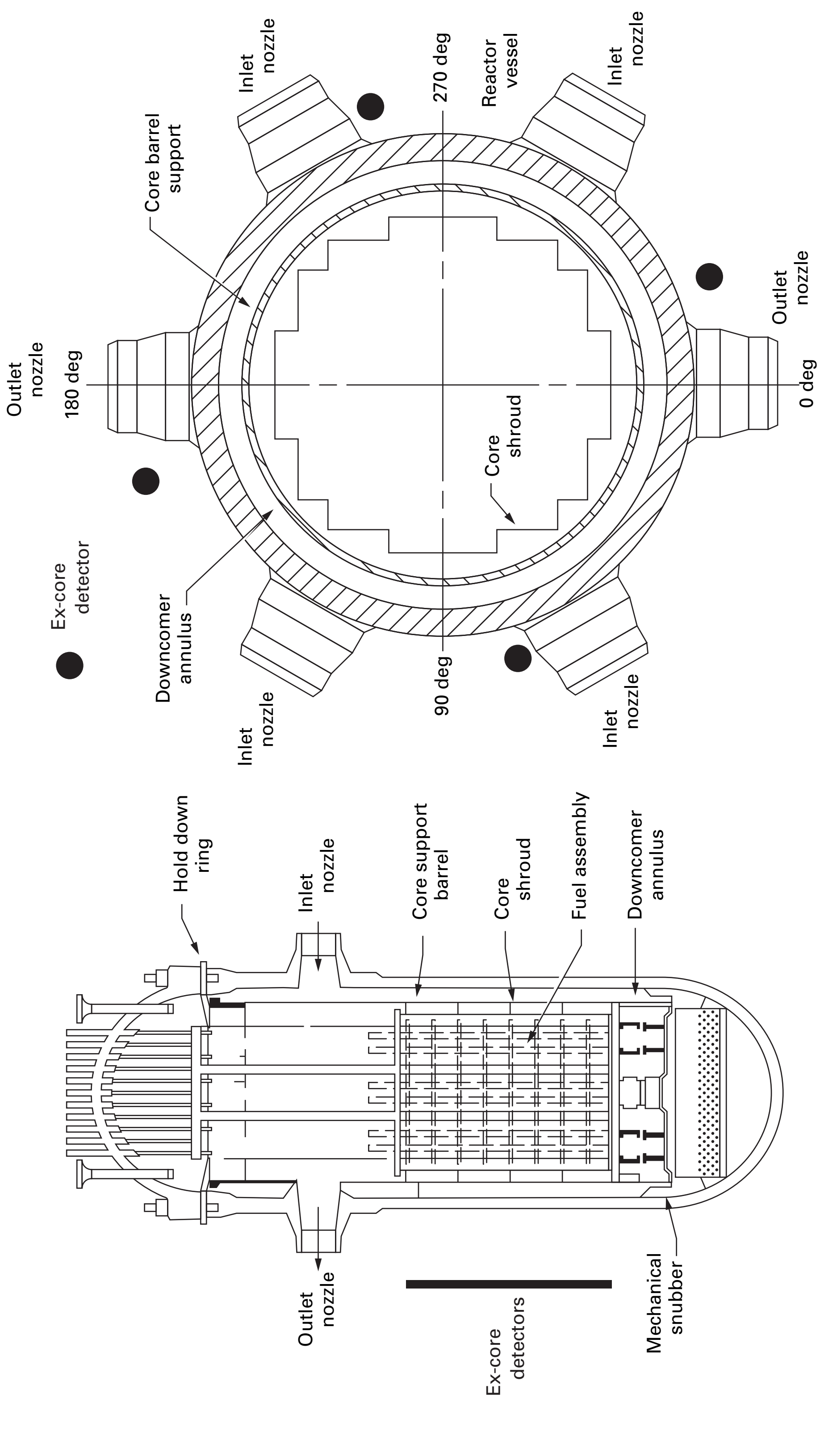
2 BACKGROUND

Figure 1 shows a cross-sectional view of a typical pressurized water reactor vessel and core support barrel. Flow-induced vibration of the core support barrel will change the thickness of the downcorner annulus (water gap), and this variation in thickness will result in corresponding variations in the neutron flux sensed by the detectors [see Fig. 1, illustration (b)].

The ex-core neutron flux signal is composed of a direct current component resulting from neutron flux produced by power operation of the reactor and a fluctuating signal or "noise" component. The fluctuating signal is associated with core reactivity changes and variations in neutron attenuation due to lateral core motion. This core motion is primarily the result of beam mode vibration of the core support barrel. Beam motion of the core support barrel is usually a very small neutron noise source, but it can be reliably identified through Fourier analysis and is typically characterized by 180-deg phase shift and high coherence between signals from ex-core detectors located on opposite sides of the core.

The natural frequencies and amplitudes of the core barrel cantilever mode of vibration are dependent on the effective axial preload at the core support barrel's upper support flange. Thus, monitoring the neutron noise signals measured by detectors located around the periphery of the reactor vessel (see Fig. 1) provides a

Fig. 1 Reactor Arrangement Showing Typical Ex-Core Detector Locations



(a) Reactor Arrangement

(b) Ex-Core Detector Locations

method for detecting a significant loss of axial preload. The relationship between beam motion of the core support barrel and neutron noise signal can be derived from the shielding equation as described in Nonmandatory Appendix A of this Part.

3 PROGRAM DESCRIPTION

The program described in this Part is intended to detect significant loss of axial preload due to long-term changes (loss of axial restraint on the core barrel resulting from abnormal wear at the reactor vessel core barrel mating surface) or short-term changes (due to improper installation of the reactor internals).

The program has three phases: baseline, surveillance, and diagnostic.

Phase	Objective	Time
Baseline	To establish reference data for use in the surveillance and diagnostic phases of the program	Initial data acquisition or startup and as indicated below
Surveillance	To compare amplitude and frequency measurements with acceptable deviations from baseline values	Periodically during operation
Diagnostic	To investigate cause and significance of changes in signals that are not within the limits established in baseline phase	As surveillance phase indicates

The baseline phase establishes reference data for use in developing limits and trends for the surveillance phase and to support data interpretation in the diagnostic phase of the program. Baseline data should be obtained at the beginning, middle, and end of each of the first three fuel cycles of a new plant or during the first fuel cycle that the program is applied in a plant that is already operating. In addition, baseline data is required when significant changes are made to the core, reactor internals, or operating conditions.

The surveillance phase of the program covers routine monitoring during normal operation over the life of the plant. Data shall be taken at the start of each fuel cycle and every 90 effective full-power days (90 EFPD) or less throughout the cycle. If a change in the neutron noise signals that the frequency or amplitude of core barrel motion is not within predetermined limits, the diagnostic phase of the program shall be initiated.

The diagnostic phase of the program is used to identify the cause and significance of unexpected changes in the neutron noise signals identified in the surveillance phase. The phase will require additional analysis of current and previous data sets taken during baseline and surveillance phases to investigate the reasons for signal changes and to establish a future course of action.

A detailed description of each phase of the program is given in sections 4 through 6. A summary of the program phases is shown in Table 1. Data reduction techniques are discussed in Nonmandatory Appendix B of this Part. Data acquisition information (instrumentation, signal conditioning, parameters, and plant conditions) is discussed in Nonmandatory Appendix C of this Part. Data evaluation (including use of acquired data, anomalies, and other experience) is presented in Nonmandatory Appendix D of this Part. Guidelines for evaluating baseline signal deviations (including data trends and user experience made available since the original release) are discussed in Nonmandatory Appendix E of this Part. Representative data are shown in Nonmandatory Appendices D and E of this Part.

4 BASELINE PHASE

4.1 Objective

The objective of this phase is to periodically establish a database for the plant to be used as reference information for the surveillance and diagnostic phases of the program.

4.2 Data Acquisition Periods

Data for use in establishing the reference database shall be collected at the beginning, middle, and end of each of the first three fuel cycles of a new plant or the initial program cycle of an operating plant and, at a minimum, after every core barrel removal, after every significant modification to the core, and after every significant modification of the reactor internals. Data should also be acquired prior to the removal of the core barrel and prior to anticipated significant modifications of the core or internals, as an aid in interpreting subsequent baseline data.

4.3 Data Acquisition and Reduction

The neutron noise time histories (analog or digital) from all functioning ex-core power range detectors (single section or summed signal from upper and lower sections) shall be recorded at each baseline phase data acquisition period. Analyses of these data shall include, as a minimum, determination of the following:

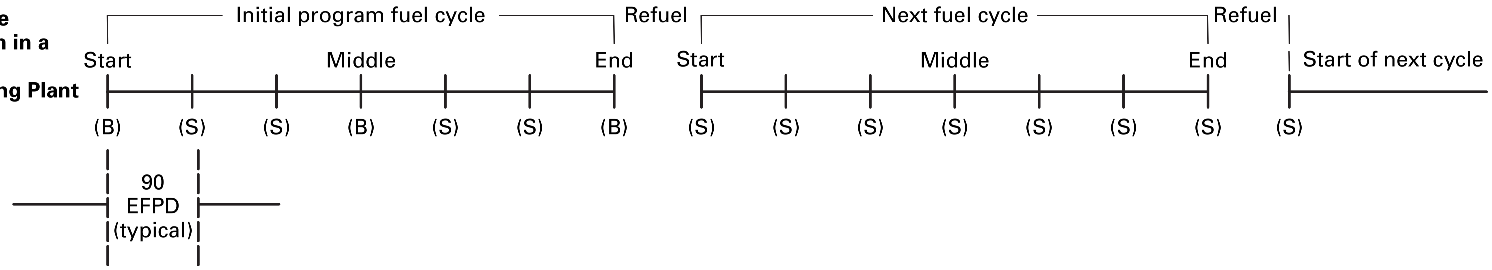
(a) normalized root mean square (nrms).

(b) normalized power spectral density (NPSD).

(c) normalized cross-power spectral density (NCPSD), phase, and coherence of all detector pairs at one deviation. If detector signals are available at more than one elevation, detector and detector pairs may be selected from more than one elevation, but signals used for a pair should be from the same elevation. As a minimum, two sets of cross-core (separated by 180 deg) detectors shall be monitored.

Table 1 Summary of Program Phases

Illustrative Program in a Typical Operating Plant



Program Phase	Frequency of Data	Data Acquisition	Data Reduction	Data Evaluation	Action
Baseline (B)	New plant: startup, middle, and end of first three fuel cycles to equilibrium Operating plant: startup, middle, and end of initial program cycle All: every significant change to core, internal, or operating conditions	Time history and DC level of each detector and each cross-core detector pair	NPSD, NCPSD, COH, and phase for each detector and all cross-core and adjacent pairs of detectors, wide- and narrow-band rms	Establish characteristic amplitude and frequency of core barrel beam motion; select wide and narrow frequency bands and establish baseline nrms values within them; develop data “trends” throughout fuel cycles	If normal, enter surveillance phase; if abnormal, enter diagnostic phase
Surveillance (S)	Start and end of each fuel cycle and every 90 EFPD during the cycle	DC levels and data for frequency analysis of each detector and two pairs of cross-core detectors separated by approximately 90 deg	NCPSD for two cross-core pairs of detectors separated by approximately 90 deg wide- and narrow-band nrms, or narrow-band nrms and beam motion center frequencies	Comparison of amplitude and frequency results with limits	If normal, continue surveillance phase; if abnormal, enter diagnostic phase
Diagnostic (D)	As indicated by surveillance results	Same as baseline	Same as baseline	Complete evaluation of data taken during surveillance phase and comparison with baseline to note changes in spectral character and magnitude	Determine cause and significance of signal anomalies; define future plant operation and/or program plan

(d) wideband and narrowband nrms values for frequency bands as defined in para. 4.4.

The data shall be analyzed over a minimum frequency band of 0.2 Hz to 20 Hz with a resolution that is consistent with amplitude and frequency changes to be deleted (see Nonmandatory Appendix C of this Part). During data acquisition, the plant shall be as close as possible to expected steady-state operating conditions.

4.4 Data Evaluation

The baseline data shall be used to establish two frequency ranges, a narrow and a wide band, and to establish the beam mode center frequency, for use in the surveillance and diagnostic phases. The narrowband range shall encompass approximately ±25% of the beam mode center frequency for the core support barrel. This band may be adjusted to remove the effects of adjacent peaks. This frequency band usually has a high coherence and 180 deg phase shifts between cross-core detectors (see Nonmandatory Appendix D of this Part). The center frequency of core barrel motion should be verified by the following:

(a) verified fluid-structural model calculations

(b) preoperational vibration measurement programs

(c) comparison with a similarly designed and constructed plant whose core barrel motion frequency has been verified by methods in subpara. 4.4(a) or 4.4(b)

A wide-band frequency range shall be established from 0.2 Hz to a minimum of 20 Hz that includes, as a minimum, responses in all anticipated support conditions.

Baseline NRMS values for both frequency ranges and beam mode center frequencies shall be determined based on both the normalized power spectral densities (NPSD) and the normalized cross-power spectral densities (NCPSD).

5 SURVEILLANCE PHASE

5.1 Objective

The objective of the surveillance phase of the program is to periodically confirm that the neutron noise nrms values are within predetermined limits. This shall be done by either periodic measurement and analysis or by a suitable continuous surveillance monitoring system. The program shall be conducted for each fuel cycle over the life of the plant.

5.2 Frequency of Data Acquisition

The data associated with the surveillance phase shall be acquired and evaluated at intervals of 90 effective full-power days or less, and at the beginning and end of each fuel cycle. Baseline data may be acquired in lieu of surveillance data.

5.3 Data Acquisition and Reduction

Data acquisition and evaluation shall be accomplished by either of the two means identified in para. 5.1. Values of nrms and center frequencies shall be determined from NCPSDs using pairs of cross-core (separated by 180 deg) detectors. The detector pairs shall be separated by approximately 90 deg. In addition, data shall be acquired to permit preparation of coherence and phase for two cross-core detector pairs at a later time. Data shall be acquired to permit detection of a significant change in either the nrms values or the center frequency of the dominant beam mode response of the core support barrel vibration.

5.4 Data Evaluation

The narrowband and wideband nrms values or narrowband nrms and core support barrel beam mode vibration frequency(ies) shall be compared to corresponding values established during the baseline phase. The acceptable range of nrms values and beam mode center frequency(ies) shall be established by the plant Owner. Allowances may be made for gradual changes in nrms and beam mode center frequency values due to nonmechanical phenomena. If the nrms values or resonance frequency fall outside the acceptable range, the program shall progress to the diagnostic phase.

Guidelines for establishing criteria for entering the diagnostic phase of the program are given in Nonmandatory Appendix D of this Part.

6 DIAGNOSTIC PHASE

6.1 Objective

The objective of this phase of the program is to establish whether or not deviations from the baseline data detected in the surveillance program are due to changes in core barrel motion, which may be indicative of loss of axial restraint, and to establish further actions to be undertaken.

6.2 Data Acquisition Periods

Initial results of this phase of the program shall indicate whether or not the minimum frequency of acquiring surveillance phase data should be increased or whether or not both the frequency and type of data acquisition and analysis should be changed from that recommended for the surveillance part of the program.

6.3 Data Acquisition, Reduction, and Evaluation

The NPSDs, NCPSDs, coherences, and phases shall be contrasted to data recorded during the baseline and surveillance program phases. Results of these and other observations (see Nonmandatory Appendix D of this Part) shall be used to indicate whether further data acquisition or analyses shall be undertaken. The trend of deviations shall be established and used to define the frequency of further data acquisition that will provide adequate indication of changes that are of sufficient magnitude to warrant further action.

If the results of data evaluation indicate possible anomalous behavior, other than sources of diagnostic information may be used (see Nonmandatory Appendix D of this Part).

Part 5, Nonmandatory Appendix A
Theoretical Basis

Using the simplifying assumption that changes in the neutron flux from core barrel motion are due only to shielding (attenuation) effects, the relationship between beam motion of the core support barrel and the neutron noise signal can be derived from the following shielding equation [1]:

$$\phi_d = \phi_o e^{-X\Sigma_r}$$

where
X = the shield thickness
ϕ_d = the instantaneous detected neutron flux
ϕ_o = the core source flux
Σ_r = the effective neutron removal cross section

The detected neutron flux after a small motion ΔX relative to the pressure vessel is then

$$\phi_d' = \phi_o e^{-(X+\Delta X)\Sigma_r}$$

The corresponding fractional change in detected neutrons is

$$\frac{\phi_d - \phi_d'}{\phi_{id}} = 1 - (e^{-\Delta X\Sigma_r})$$

which for small $\Delta X\Sigma$ becomes

$$\begin{aligned}\frac{\phi_d - \phi_d'}{\phi_d} &= 1 - (1 - \Delta X\Sigma_r) \\ &= \Delta X\Sigma_r\end{aligned}$$

so that

$$\Delta X = \frac{1}{\Sigma_r}\frac{\phi_d - \phi_d'}{\phi_d}$$

For dynamic measurements, $(\phi_d - \phi_d')$ is the instantaneous neutron noise voltage such that

$$\Delta X(t) = \frac{1}{\Sigma_r}\left[\frac{\Delta\phi(t)}{\phi_d}\right]$$

or

$$\Delta X(\omega) = \frac{1}{\Sigma_r}\left[\frac{\Delta\phi(\omega)}{\phi_d}\right]$$

The rms motion in a particular frequency band is

$$\Delta X_{\mathrm{rms}} = \frac{1}{\Sigma_r}\frac{\left\{\int_{f_2}^{f_1}[\Delta\phi(\omega)]^2 d\omega\right\}^{1/2}}{\phi_d}$$

or

$$\Delta X_{\mathrm{rms}} = \frac{1}{\Sigma_r}\left[\int_{f_2}^{f_1}\mathrm{NPSD}(\omega)d\omega\right]^{1/2}$$

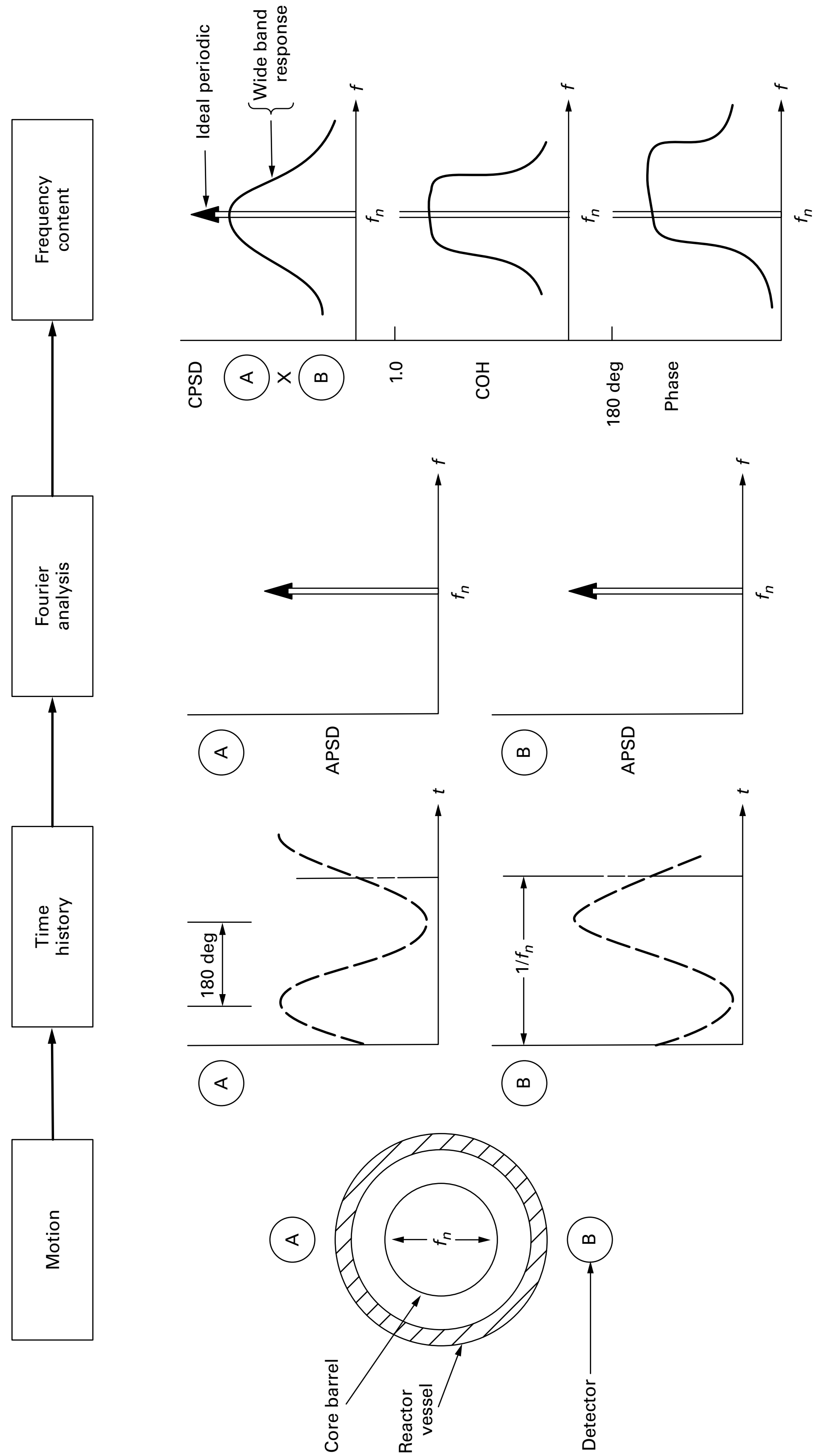
where
$NPSD(\omega)$ = the normalized neutron noise power spectral density (PSD) obtained by dividing the noise voltage PSD by the square of the mean value voltage from the detector ($\overline{\phi}_d$)
= $\mathrm{PSD}(\omega)/\overline{\phi}_d^{\,2}$

Power spectral density, so normalized, is used throughout this Part. Conversion of this normalized value (units of fraction of noise) to amplitude of motion (units of mils) is discussed in Nonmandatory Appendix F of this Part. For lateral motion at the beam frequency, signals from cross-core detectors will be 180 deg out-of-phase (maximum one side, minimum opposite side) [2, 3]. Furthermore, these cross-core signals will have a high value of coherence generally between 0.5 and 1.0. Example signals for one cycle of motion are shown in Fig. A-1.

More complete reviews of the relationship between ex-core detector signals and internals motion appear elsewhere [4, 5].

An overview of experience with excore monitoring of core barrel motion also appears elsewhere [1, 6, 7].

Fig. A-1 Idealized Analysis for Core Barrel Motion



Part 5, Nonmandatory Appendix B Data Reduction Techniques

The following is a brief description of various parameters used in baseline, surveillance, and diagnostic programs to identify core barrel motion [8]. It should be noted that all parameters are normalized to the operating power level (the DC value of the excore detector signal).

B-1 NORMALIZED POWER SPECTRAL DENSITY (NPSD)

The normalized power spectral density (the auto-power spectral density or APSD divided by the DC signal level squared) is a decomposition of a stochastic function into functions of frequency [Fig. B-1, illustration (a)]. It provides a measure of the signal power (mean square level) within discrete frequency bands over specified frequency ranges. The sampling rate, sampling time, and sample size are governed by the frequency range and bandwidth.

B-2 NORMALIZED ROOT MEAN SQUARE OF THE SIGNAL

The normalized root-mean-square (nrms) value of the neutron noise signal is a measure of the amplitude of core barrel motion. However, it may include systematic variations due to changing plant conditions [e.g., burnup, changes in β_{EFF} (delayed neutron fraction) reactivity coefficients, and the like], which can contribute to a change in the nrms level. Since the nrms level is normalized to the DC level, it is dimensionless.

The rms value of the band f_1 to f_2 can be computed from NPSD as follows:

$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NPSD}\, df$$

The NPSD can be used to calculate that portion of the total excore response related to core barrel motion. Observed over an extended period of time, it provides a sensitive measure of changes in motion.

The NPSD is expressed as signal voltage squared per DC signal voltage squared per unit of frequency (1/Hz).

B-3 NORMALIZED CROSS-POWER SPECTRAL DENSITY (NCPSD), COHERENCE (COH), AND PHASE (ϕ)

B-3.1 Normalized Cross-Power Spectral Density (NCPSD)

The NCPSD (the cross-power spectral density or CPSD divided by the product of the DC level of the two signals) provides a descriptor of commonality between two excore detectors [Fig. B-1, illustration (b)]. The ability of the NCPSD to discount noncoherent portions of the signal better defines the region of motion, and when used in conjunction with the coherence and phase, is preferred over the NPSD as a governing statistic for establishing core barrel motion.

The rms value over frequency band f_1 to f_2 can be computed as follows:

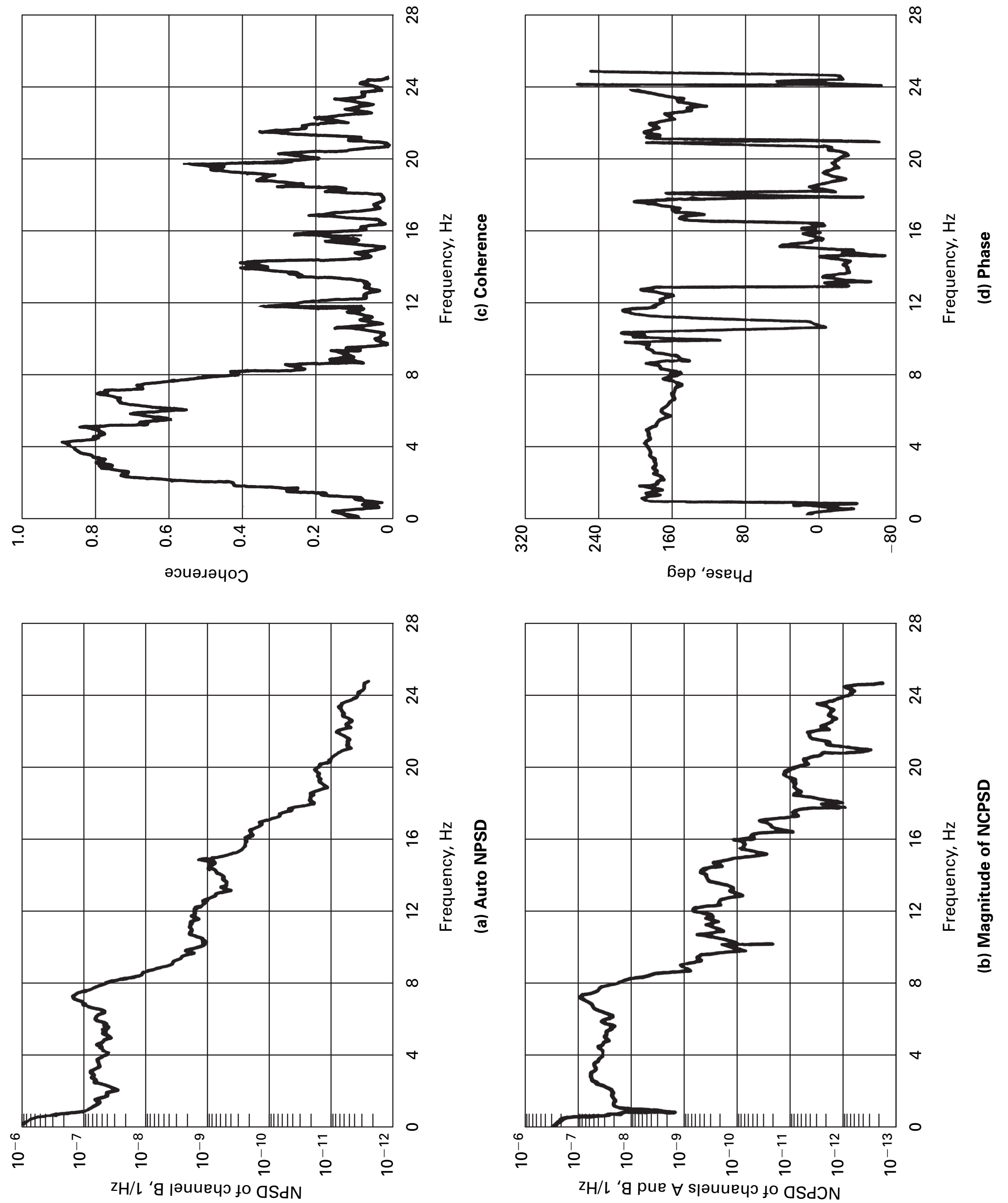
$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NCPSD}\, df$$

The NCPSD is expressed as the product of signal voltages per product of DC voltages per unit of frequency (1/Hz).

B-3.2 Coherence (COH) and Phase (ϕ)

Although the NCPSD is a measure of the commonality between two variables, it is most convenient to represent the similar character in relative terms, relative to the individual signal NPSDs. This is done by calculating the coherence functions. The coherence is defined as the ratio of the square of the magnitude of the NPSD to the product of the individual NPSDs and is bounded between zero and one [Fig. B-1, illustration (c)]. If the coherence is one, the two signals are said to be fully coherent and, therefore, closely related. The corresponding phase data in this case are valid. Uncorrelated signals will have coherences approaching zero, rendering any phase data meaningless [Fig. B-1, illustration (d)]. Coherence is dimensionless, while phase is expressed in degrees.

Fig. B-1 Representative Spectra



Part 5, Nonmandatory Appendix C
Data Acquisition and Reduction

C-1 INSTRUMENTATION

Neutron noise measurements can be made with prompt responding neutron detectors such as those used for plant monitoring and control. The output of these detectors is commonly conditioned by direct coupled current-to-voltage conversion equipment and linear amplifiers. Neutron noise measurements remove the mean value of the signal and provide additional amplification of the dynamic component. The amplified neutron noise signals can be analyzed online and in real time or recorded on magnetic tape for later processing.

C-2 SIGNAL CONDITIONING

Neutron noise signals are typically very small magnitude compared to the mean value neutron flux and to possible electrical noise interference. Precautions should be used to minimize electrical noise pickup and to obtain adequate dynamic range in the frequency band of interest.

(a) The noise floor of the signal conditioning equipment should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) Filters and input common mode rejection should be used to limit electrical interference and signals outside the frequency band of interest to within the dynamic range of the signal-conditioning equipment.

(c) Signal-conditioning gains should be set so that noise introduced by normal plant operations (such as small control rod motion) do not overload the signal conditioning equipment during data acquisition.

(d) Neutron noise signals derived from plant control instrumentation should be examined for evidence of noise induced by plant-monitoring instrumentation.

(e) Calibrations should be used to verify and correct for any variation in the frequency response of the instrumentation in the frequency band of interest.

C-3 DATA ACQUISITION PARAMETERS

Data recording introduces instrumentation, noise, and dynamic range limits on neutron noise signals. These limitations should be recognized and appropriate action taken to preserve adequate signal quality.

(a) The noise floor of the reproduced signal should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) The signal conditioning and tape recorder input controls should be adjusted so that no signals exceed the maximum tape recorder input during data acquisition.

(c) The frequency response of the data recording system in the frequency band of interest should be verified.

(d) Digital recording systems should have sufficient amplitude resolution and input filters to reduce all conversion noise and aliased signal components to at least 10 dB below the expected neutron noise signal in the frequency band of interest.

C-4 PLANT CONDITIONS FOR DATA ACQUISITION

Plant operating parameters and changes in these parameters contribute to the interpretation of neutron noise signals. These should be measured and noted at the beginning and end of each neutron noise data acquisition.

(a) Plant parameter changes are a potential source of neutron noise. The measurement of vibration-related neutron noise should be done as close to steady-state plant conditions as possible to minimize other noise sources.

(b) Primary plant parameters should be logged as part of each neutron noise measurement. Parameters to be documented during data acquisition are listed in Table C-1.

C-5 DATA REDUCTION PARAMETERS

Data reduction can introduce noise and statistical uncertainty into neutron noise data. These potential sources should be recognized and controlled in data analysis.

(a) The noise floor of the data reduction methods should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) Digital analysis systems should have sufficient resolution and input filtering to reduce all aliased signal components to at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(c) All neutron noise measurements should be normalized as a fraction of the mean value of the detector signal.

(d) The frequency resolution of spectral density measurements should be at least 1% of the highest calculated frequency.

Table C-1 Parameters to Be Documented During Data Acquisition

All Data	Plant name and unit number Date and time of data acquisition Plant conditions: power level, coolant flow rates, number of pumps operating, soluble boron concentration, fuel burnup (EFPD), fuel cycle number, system pressure, pressurizer level, control rod positions, and hot-leg and cold-leg temperatures for each loop Names of persons performing data acquisition Identification of signals Description of sensors including manufacturer, model number, serial number, and calibration data Description of signal conditioning equipment Gains of all devices between point of dc measurement and output of tape recorder or input to spectrum analyzer DC voltages at input to signal conditioning equipment Frequency cutoffs of filters
Tape Recordings	Description of tape recorder Tape number or identifier Recording format Starting and stopping tape footages Type of calibration signals recorded (should be recorded on each tape) and footages Tape speed
On-Line Analysis	Anti-aliasing filter settings Sampling rate Analysis window type Sample block size Frequency resolution Amount of data overlap Units of results Description of analyzer Gain of analyzer front end

(e) The data record length for rms measurements and power spectral density measurements should provide a minimum of 100 ensemble averages without data overlap (see section C-9).

(f) Relevant plant conditions and data reduction parameters should be indicated on reduced data. These include signal identification, reactor power, measurement data, analysis bandwidth, and data length.

C-6 SIGNAL BUFFERING

It is preferable that the signals to be used for analysis be routed to a common panel. These signals should be fully buffered and isolated prior to common routing. The buffer circuitry shall not induce noise that would neither cause the noise floor to be greater than 10 dB below the expected neutron noise signal nor degrade the frequency band of interest. The isolation should be adequate to ensure that a short circuit at the connection point will not adversely affect plant operation.

C-7 DATA ASSURANCE

Methods and procedures should be used to ensure the quality of the neutron noise data.

(a) Plant signals should be verified and permanently attached by acceptable methods to the data acquisition/processing system. Otherwise, connections must be verified at each measurement.

(b) Data acquisition should be performed according to a written procedure.

(c) Documentation of the data should include those parameters listed in Table C-1.

(d) Reduction of neutron noise data and display of analysis results should be performed in a consistent manner to facilitate comparison of the results over the lifetime of the plant.

C-8 DATA RETENTION

Baseline and surveillance data should be retained over the lifetime of the plant.

C-9 STATISTICAL UNCERTAINTIES IN NEUTRON NOISE DATA ANALYSIS

Definitions of noise descriptors (auto- or cross-correlation, PSD, CPSD, phase, and coherence) for random data involve limiting conditions that cannot be carried out in practice (i.e., analysis of an infinite number of time records or a time record of infinite time span). The inability to perform these operations under practical conditions leads to statistical errors in the analysis. These statistical errors are expressed as "random error" or residual uncertainty variance. In addition, some estimates may also be biased error.

Bias errors are usually associated with measurements of the amplitude of a resonance in the frequency spectrum. The bias error formulas for the PSD and CPSD magnitude are [9]

$$-1/3(\Delta f/B_r)^2 \tag{C-1}$$

where Δf is the analysis frequency resolution and B_r is the true (unbiased) half-power bandwidth of a resonance. This formula does not hold for small numbers of ensemble averages and low coherences. The negative sign indicates that the bias errors result in estimated amplitudes that are lower than the true value. Bias errors can be reduced by using a finer frequency resolution in the analysis.

Bias errors associated with coherence (Y^2) follow the following formula:

$$\hat{Y}^2 - Y^2 = \frac{1}{n_d}(1 - Y^2)^2 \tag{C-2}$$

where n_d is the number of ensemble averages, Y^2 is the true coherence, and $\hat{Y}^2$ is the estimated coherence. This formulation indicates that if the true coherence is zero, the estimated coherence will be 1 for a 1 block average. Bias errors in the coherence are therefore reduced by increasing the number of ensemble averages.

Statistical errors in the PSD are given by

$$\sigma_{\mathrm{PSD}}/\widehat{\mathrm{PSD}} = 1/\sqrt{n_d} \tag{C-3}$$

and in the CPSD by

$$\sigma_{\mathrm{CPSD}}/\widehat{\mathrm{CPSD}} = 1/\sqrt{Y^2 n_d} \tag{C-4}$$

where σ is the standard deviation and $\widehat{\mathrm{PSD}}$ and $\widehat{\mathrm{CPSD}}$ are the mean values of the PSD or CPSD. For PSDs, this indicates that a single frequency estimate will have an uncertainty of ±30% at the 99% confidence (3 standard deviation) level for 100 ensemble averages.

The statistical error for the coherence [10]

$$\frac{2\hat{Y}^2}{n_d}(1 - \hat{Y}^2)^2 \tag{C-5}$$

and for the CPSD [eq. (C-4)] depends on both the number of ensemble averages and the coherence. For low coherence, a large number of ensemble averages are needed to meet a given statistical error.

Experience in reactor noise analysis indicates that a minimum of 100 ensemble averages (without overlap) should be performed in estimating noise parameters and their statistics. Overlap processing can yield improved statistics for a fixed amount of data, but the minimum number of averages without overlap should be at least 100 (e.g., 100 nonoverlapping averages yields 200 averages with 50% overlap). Some analyzers invoke overlap processing automatically. In these cases, the amount of overlap should be determined and the number of averages adjusted upward to meet a desired statistical confidence level.

While these formulas serve as guides, the actual statistical behavior of data from a particular reactor should be verified by the noise analyst.

Part 5, Nonmandatory Appendix D
Data Evaluation

The various methods of reducing the data are of use only when subject to proper interpretation. This interpretation involves an evaluation of the data in conjunction with a knowledge of parameters (i.e., frequencies and mode shapes) related to core barrel motion. Equally important is an understanding of how a variety of neutronic effects can influence these data.

Experience has shown that the neutronic effects can be of the same magnitude as the vibration effects, which can lead to misinterpretations of the data. Careful examination of all data is required to separate out any effects that are not due to vibration from the neutron noise information.

The following is a listing of the information on core barrel motion and other types of noise effects that can be obtained from an evaluation of the spectral analysis data during each phase of the program.

D-1 BASELINE

D-1.1 Normalized Root Mean Square (nrms) Value

Baseline nrms values in both narrowband and wideband frequency ranges or the narrowband nrms value and center frequencies of core barrel beam motion may be used as a basis for comparing values obtained during the surveillance phase. Experience has shown that baseline nrms values can change from refueling to refueling and with changes in core parameters such as burnup and boron concentration. Thus, it may be desirable to re-evaluate baseline nrms values more frequently than the minimum schedule given in para. 4.2.

To establish the narrowband rms baseline values, the center frequency of the core barrel beam mode must be identified as described in para. 4.3. A frequency range of approximately ±25% of the center frequency is used to bound the narrowband region as shown in Fig. D-1, illustration (a). Adjacent peaks may be omitted from the narrowband region as shown in Fig. D-1, illustration (b). These methods may be used to define the narrowband rms baseline value for either a continuous or periodic monitoring system.

Small changes may be found in the amplitude and/or center frequency, as shown in Fig. D-1, illustration (c), when baselines are taken. Significant changes, however, may indicate improper core barrel preload or other structural concerns that should be diagnosed.

The detector nrms signal levels will include components that are essentially uncorrelated between cross-core detectors and, therefore, are not due to lateral core support barrel motion. Furthermore, the nrms value in the low frequency band can increase with core burnup because of low frequency neutronic effects. These effects reduce the ability to distinguish core barrel motion changes from neutronic effects and require that the trend with burnup be considered in establishing values representing significant changes in the measured data.

Experience has shown that, in a number of reactors, a wideband (0 Hz to 25 Hz) nrms value will increase linearly with operating time, measured in burnup and/or decreasing boron content. This is because neutronic effects related to thermal noise and/or fuel motion tend to increase with burnup and dominate the true beam motion portion of the signal. Thus, wideband nrms values versus burnup should display a linear trend (Fig. D-2) [11]. Significant changes from this trend would warrant a diagnostic phase investigation of the signal.

D-1.2 Normalized Power Spectral Density (NPSD)

The NPSD of an excore detector signal contains contributions due to actual motion and extraneous noise. As such, while its frequency spectra may be a good indicator of the frequency of motion, its amplitude will be higher than that due to the motion. Recognizing this limitation, the NPSD signal of each detector may be reviewed to note the following within the frequency range of core barrel motion:

(a) changes in amplitude

(b) shifts in frequency of the maximum amplitude

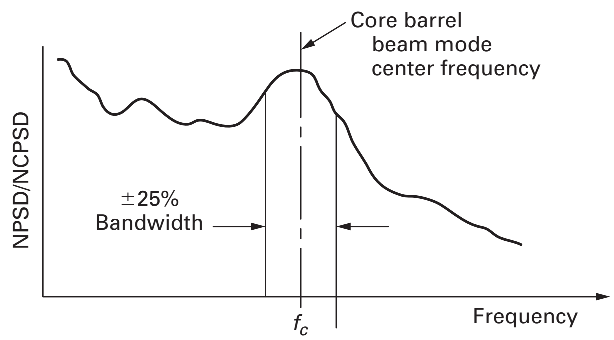
A significant change (increase or decrease) in amplitude or frequency, or both, may be indicative of changes in core barrel motion.

NPSDs will indicate the predominant core barrel frequency as a function of detector location. This may shift slightly from baseline to baseline due to changes in barrel position after refueling, broadening, or narrowing of the peak due to changing neutronic effects (e.g., fuel loading pattern, boron or burnup related).

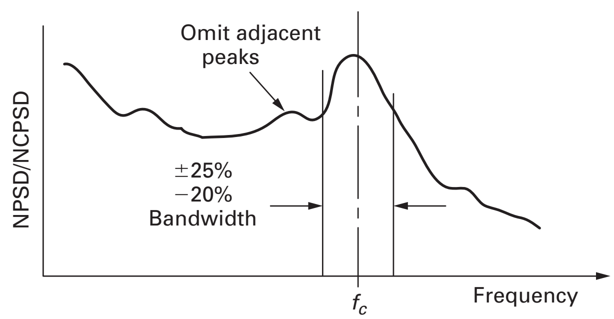
D-1.3 Normalized Cross-Power Spectral Density (NCPSD), Coherence (COH), and Phase (ϕ)

The characteristic that the NCPSD does not include the effects of detector, or other noise sources, makes it, in conjunction with COH and ϕ, the most reliable indicator of core barrel motion. Investigations have

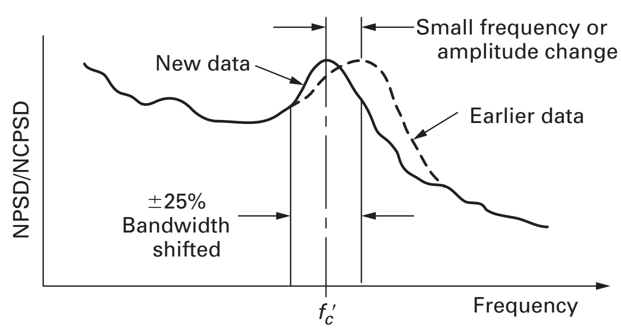
Fig. D-1 Narrowband rms



(a) Narrowband rms Region

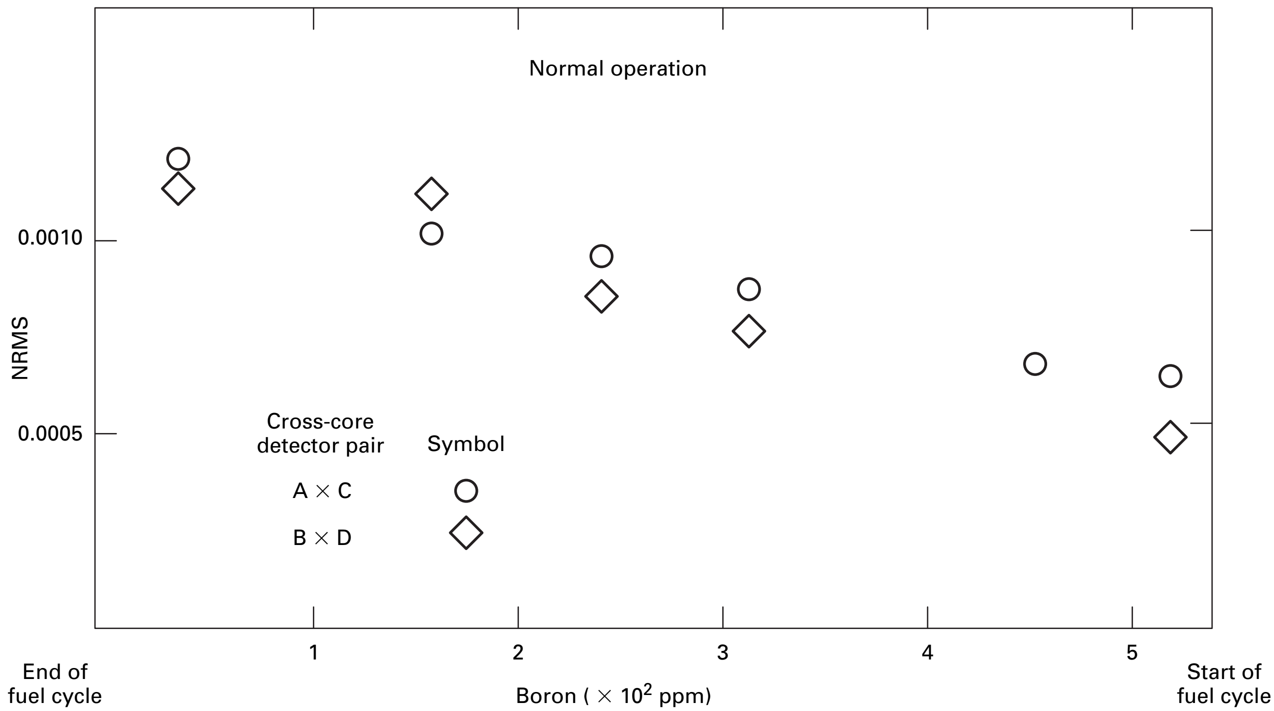


(b) Modified Narrowband rms Region



(c) Narrowband rms Redefined

Fig. D-2 Example of Wideband rms Amplitude Versus Boron Concentration



shown that core barrel motion often follows a preferred (though random) path, resulting in the following COH and ϕ results:

Detector Pairs	COH	Phase, ϕ
Cross-core	High (0.5 to 1.0)	Out-of-phase (~180 deg)
Adjacent, 90 deg apart	Low (~0.2)	Data not reliable

These relationships are based on core barrel beam mode vibration being the predominant contributor. Recent experience has shown that higher order fuel assembly vibrations and effects from fuel management changes can cause the phase and coherence relationships to be quite different even though no structural changes have occurred [12]. These data need to be carefully evaluated along with the NPSDs to verify core barrel motion.

Baseline NCPSDs are the best indication of frequency ranges for the subsequent surveillance phase rms measurements. The absence of a dominant peak within the expected core barrel frequency range, in combination with an order of magnitude greater in low frequency (0 Hz to 5 Hz) noise amplitude as compared with the expected amplitudes, should be taken as an indication of possible loss in core barrel axial restraint.

D-2 SURVEILLANCE PHASE

D-2.1 Root Mean Square

Root-mean-square values are to be calculated from the NCPSD functions in the manner shown by Nonmandatory Appendix B of this Part and compared with the values determined from the baseline measurements. Any unexpected deviation from known trends should instigate a diagnostic phase investigation.

D-2.2 Normalized Cross-Power Spectral Density (NCPSD)

NCPSD values shall be generated for two pairs of cross-core detectors during this phase and evaluated for magnitude and frequency changes in the core barrel motion frequency range. Any unexpected deviation from known trends should instigate a diagnostic phase investigation.

D-2.3 Coherence (COH) and Phase (ϕ)

Data shall be obtained so that COH and ϕ plots can be generated, if needed, for two pairs of diametrically opposed detectors. Review of these data and comparison with corresponding data obtained in the baseline phase may provide additional information on core barrel behavior.

D-3 DIAGNOSTIC PHASE

D-3.1 Normalized Root Mean Square (nrms)

(a) The nrms value, as computed from the NPSD and NCPSD, can be used as a check on values obtained during the surveillance program.

(b) The most accurate assessment of the amplitude of CSB motion can be obtained from a narrowband (± 25%

of the core barrel frequency) calculation of the rms value based on the NCPSD of two diametrically opposite detectors.

(c) While the nrms value is an easily obtained parameter, its value alone is not an adequate measure of the amplitude of core barrel motion. Additional information on predominant frequency of the motion, based on cross-core coherence and phase information, is required for a complete assessment of the motion. These latter parameters can be obtained, in part from the NPSD and completely from the NCPSD.

D-3.2 Normalized Power Spectral Density (NPSD)

When compared with baseline values for that fuel cycle, NPSDs generally show an increase in amplitude with fuel burnup at lower frequencies (to approximately 0 Hz to 5 Hz) due to neutronic effects. This increase, depending on the core barrel frequency, may result in a broadening of the core support barrel motion-related peak.

D-3.3 Normalized Cross-Power Spectral Density (NCPSD), Coherence (COH), and Phase (ϕ)

The NCPSD, COH, and ϕ can be used in the diagnostic program to best ascertain the nature of the motion and determine if changes in wideband or band-limited rms values from the surveillance program are related to changes in CSB motion. This would be done as follows:

(a) Note changes in coherence, in both magnitude and frequency of the maximum value, within the frequency range of core barrel motion. A change in frequency range of the coherence may be indicative of a change in frequency of core barrel motion. A change in amplitude may be indicative of a change in axes of motion.

(b) Note changes in phase within the same frequency range. A change in phase may be indicative of a change in axes of motion.

(c) Note changes in peak amplitude and frequency of this peak, both within and below this frequency range.

(d) Note changes in band-limited nrms amplitude in both core barrel frequency range and below this range.

A change in amplitude, frequency, and rms value may be indicative of a change in characteristics of core barrel motion (e.g., an increase in frequency may be due to a fixed end condition at one of the mechanical snubbers, while a decrease may be due to a lessening of the fixed end condition at the barrel-vessel flange interface). The latter may be due to a change in axial restraint, abnormal wear, or both.

D-3.4 Additional Sources of Information

To support the diagnostic phase of the program, other sources of information may be used, such as the following:

(a) loose parts accelerometers

(b) in-core detector noise

(c) loose parts monitoring system results

(d) core power distribution monitoring (tilts, axial flux changes, power peaking)

(e) primary pressure, temperature, flow distribution

(f) structural analysis of internal structures and boundary condition effects on frequencies and mode shapes

(g) plant operating history

(h) results from the Comprehensive Vibration Assessment Program for Reactor Internals During Pre-Operational and Initial Startup Testing Program (Regulatory Guide 1.20)

Part 5, Nonmandatory Appendix E
Guidelines for Evaluating Baseline Signal Deviations

Typical ex-core neutron noise signatures for six pressurized water reactors are shown in Fig. E-1 with the corresponding range in power spectral density shown in Fig. E-2 [7, 13]. Changes in the neutron noise signature over a fuel cycle, including refueling, are shown for one plant in Fig. E-3 [7]. For comparison, a neutron noise spectrum from a plant with a loss of axial preload on the core support barrel flange is shown in Fig. E-4 [14]. These figures illustrate the range in neutron noise signature amplitude and frequency content between different plants and the major change in the shape of the core support barrel resonance frequency response region of the spectrum and a major increase in low frequency neutron noise associated with complete loss of axial clamping. Additional information on loss of axial preload obtained from reduced scale model tests is available [15].

Decreases in axial clamping force are expected to lead to decreases in the core support barrel beam mode frequency and to increases in the magnitude of the beam mode response. Criteria for entering the diagnostic phase should be based on a combined increase in core barrel resonance response rms amplitude and a simultaneous decrease in the core barrel beam mode resonance frequency, or a complete loss of the core barrel resonance frequency combined with a large increase in low frequency neutron noise.

Operating experience indicates that allowances must be made for increases in the neutron noise level as a function of core burnup and/or decreasing boron concentration, as well as for changes in fuel management and in core barrel contact with the reactor vessel mechanical snubbers that can affect the neutron noise signatures in some plant designs. These allowances will improve the ability to detect loss of axial clamping before the core barrel becomes completely free and capable of wear against the reactor vessel and will reduce the number of times that the diagnostic phase must be entered. The capability to develop these allowances on a plant-specific basis is provided by the baseline and surveillance phase data acquisition requirements.

Fig. E-1 Typical Ex-Core Neutron Noise Signatures From Six PWRs

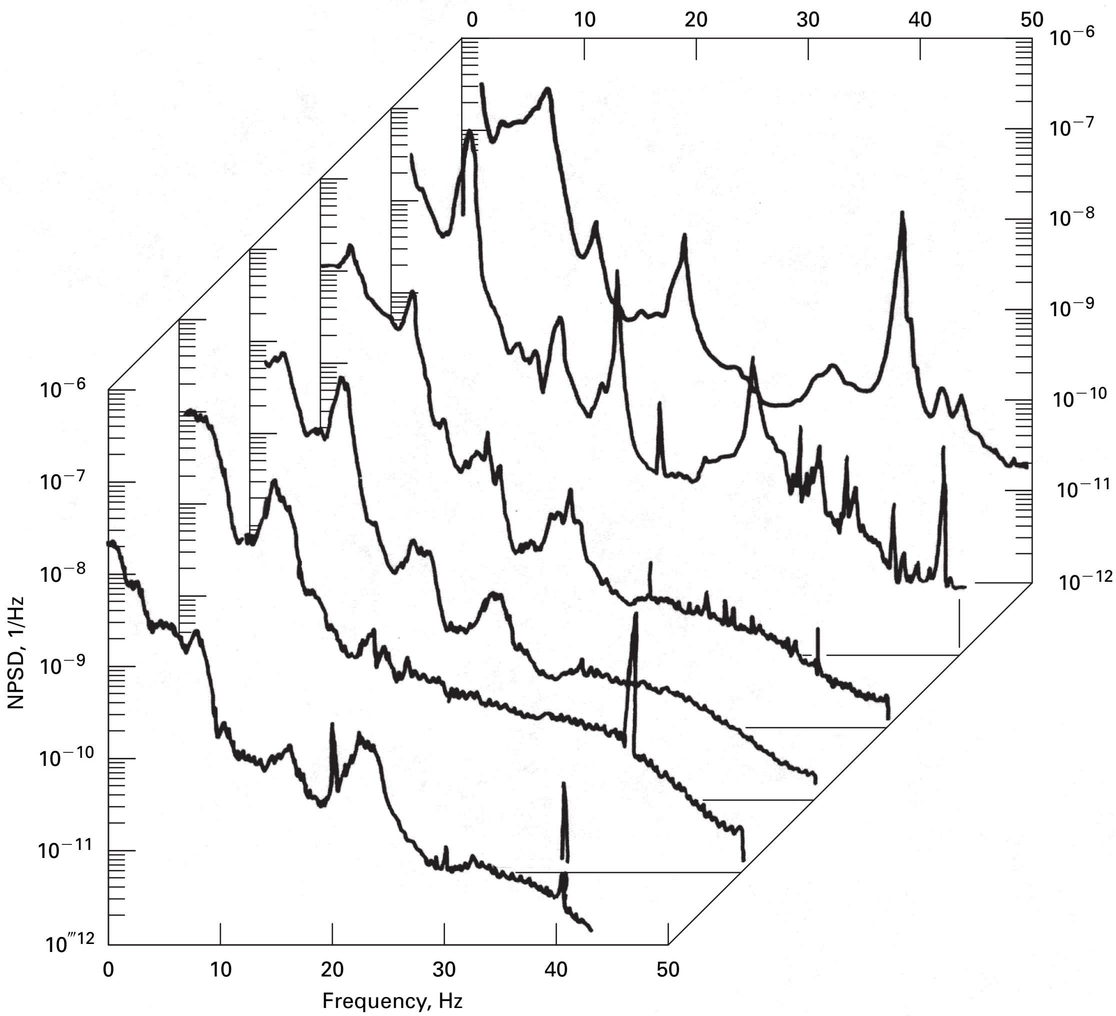
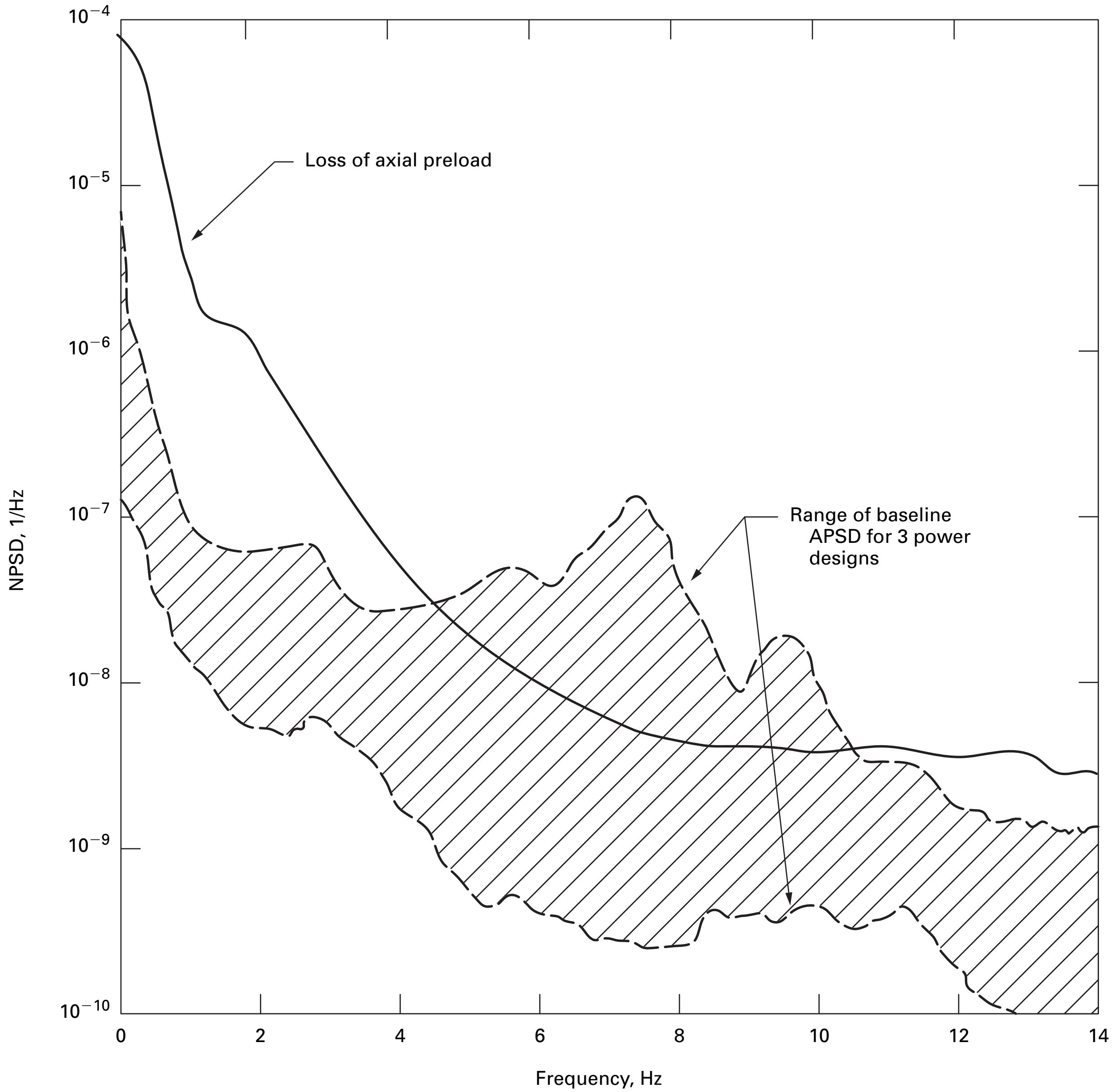


Fig. E-2 Typical Baseline NPSD Range



GENERAL NOTES:

(a) Range of Baseline nrms Values for Normal Operation 4×10^{-4} to 10×10^{-4}.

(b) Loss of Axial Preload nrms Value 0.02.

Fig. E-3 Examples of Changes in the Neutron Noise Signature Over a Fuel Cycle

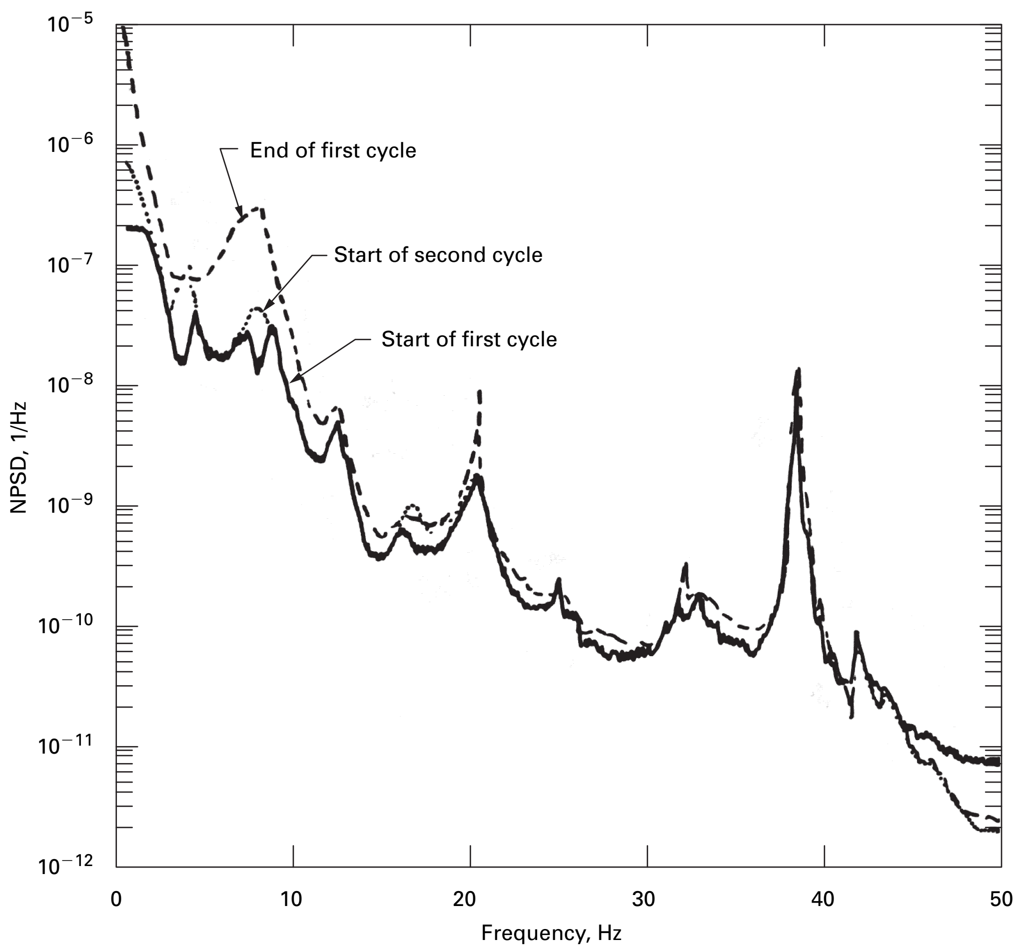
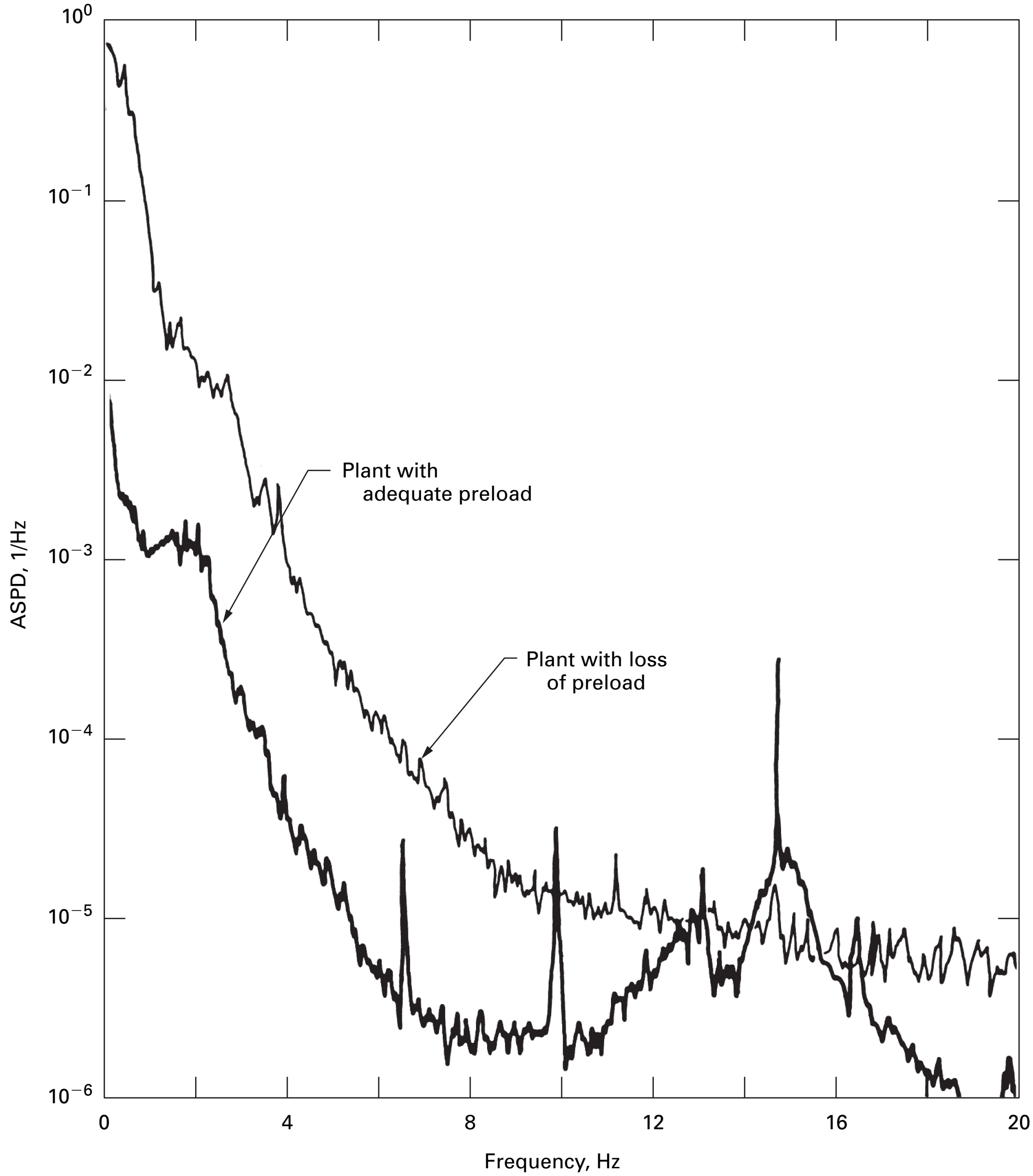


Fig. E-4 Example of Loss of Axial Restraint



Part 5, Nonmandatory Appendix F
Correlation of rms Amplitude of the Ex-Core Signal (Percent Noise) and Amplitude of Core Barrel Motion

To convert amplitude of the neutron noise signal, expressed as fraction of noise (rms value of the random signal divided by the average or DC value of the signal at the same operating conditions), to amplitude of core barrel motion, expressed in units of length, a scale factor (1/length) relating these quantities must be found. This may be done by experimental and/or theoretical means for the specific reactor design. Table F-1 lists the range found in the referenced literature.

The values presented in Table F-1 are derived on the assumption that ex-core neutron noise resulting from core barrel motion is due only to neutron shielding (attenuation) effects. Experience in monitoring ex-core neutron noise has shown that additional noise sources (e.g., fuel motion, burnup, soluble boron, and moderator density changes) may be significant [12]. If these effects can be accounted for, the factors in Table F-1 may be used to estimate the amplitude of core barrel motion for a specific reactor design.

Table F-1 Ratio of the Amplitude of the Neutron Noise to Core Barrel Motion

Value, 1/mil (1/mm)	Comments
0.00038 (0.015) [2]	Measured; based on change of neutron flux with temperature
0.0003 (0.012) [16]	Calculated; one-dimensional transport model
0.00043 ± 0.000064 (0.0185 ± 0.00661) [17]	Measurements based on ex-core detector and core barrel accelerometer transfer function
0.00025/0.00015 max. (0.0098/0.0059) [18]	Maximum calculated by two-dimensional transport model (into shield/at shield surface); factor is a function of angle between axes of motion and detector location

Part 5, Nonmandatory Appendix G
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Part 7
Requirements for Thermal Expansion Testing of Nuclear Power Plant Piping Systems

1 SCOPE

This Part provides guidance for preservice and inservice testing to assess the thermal expansion of certain piping systems used in LWR power plants.

The piping covered is that required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

acceptable limits: specified range of numerical values of pipe response that satisfy acceptance criteria. An acceptable limit is usually expressed as the expected analytical response with an allowable range or tolerance.

ASME B31: ASME Code for Pressure Piping.

BPV Code: ASME Boiler and Pressure Vessel Code.

commercial operation: plant operation after completion of start-up testing.

design basis temperature: maximum temperature defined in the design basis thermal expansion analysis.

Design Specification: the document provided by the Owner, as required by NCA-3250 or NA-3250 of the BPV Code, Section III, for the component/system, which contains requirements to provide a complete basis for the construction of the component/system.

design verification: the process of reviewing, confirming, or substantiating a design by one or more methods to provide assurance that the design meets the specified design input.

discrepant response: thermal expansion response that falls outside acceptable limits.

hot shimming: the process of adjusting support and restraint clearances in the hot condition.

inaccessible piping: piping systems or portions thereof that are not accessible to personnel. The inaccessibility may be the result of adverse environmental conditions during the test, location of the piping, or mechanical or structural encasement.

initial start-up testing: test activity performed during or following initial fuel loading but prior to commercial operation. These activities include fuel loading, precritical tests, initial criticality tests, low power tests, and power ascension tests.

maintenance/repair/replacement: actions taken to prevent or correct deficiencies in the system operation.

normal operating conditions: the service conditions the system would experience when performing its intended function.

operational testing: test activities performed subsequent to initial start-up testing (e.g., testing performed during commercial operation of the plant).

Owner: the organization legally responsible for constructing and/or operating a nuclear facility including, but not limited to, one who has applied for or who has been granted a construction permit or operating license by the regulatory authority having lawful jurisdiction.

peripheral equipment: device(s) used in the setup, checkout, or on-site calibration of the other thermal expansion monitoring system (TEMS) devices.

physical units: the engineering units that quantitatively represent the measured variable (e.g., if the measured variable is displacement, the physical units can be inches, mils, meters, etc.).

piping system: an assembly of piping subassemblies and components and their supports whose limits and functions are defined in its Design Specification.

preoperational testing: test activities performed on piping systems prior to initial fuel loading.

processing equipment: device(s) used for further handling, reformatting, or manipulation of the transducer output to reduce it to manageable or intelligible information.

recording and display equipment: recording equipment devices are used for storing signals in a form capable of subsequent reproduction; display equipment devices are used to obtain a visual representation of a signal (conditioned and/or processed transducer output).

signal conditioner: device(s) used to modify or reformat the transducer output to make it intelligible to or compatible with processing equipment.

TEMS specification: a document that uniquely describes the thermal expansion measurement system.

test conditions: the conditions experienced by the system when undergoing tests.

test hold points: events in the test program usually associated with system operating conditions, for which test information is to be collected; for example, with the reactor at *X*% power or with the system at full flow.

test specification: the document(s) prepared by the Owner or his designee that meet the requirements set forth in section 3.

thermal expansion measurement system (TEMS): the instrumentation or test equipment used to measure and record the thermal expansion data.

transducer: a device that converts the piping response into an optical, mechanical, or, typically, an electrical signal, which is proportional to a parameter of the piping response.

3 GENERAL REQUIREMENTS

The Owner shall determine and document the scope of piping systems to be monitored for thermal expansion during preoperational and initial start-up testing. The Owner shall also determine the monitoring techniques that would satisfy the minimum requirements for testing and acceptance criteria outlined in this Part.

The primary objective of the thermal expansion test program of a piping system shall be to verify that the piping system expands within acceptable limits during heatup and returns to an acceptable position when cooled down without adverse constraint. Acceptable limits shall be established using the considerations stated in para. 3.2.

The secondary objective of the test program shall be to verify that the component standard supports (including spring hanger, snubber, and strut) can accommodate the expansion of the pipe within the range of the component's capability for all specified modes of operation.

Other general requirements are as follows:

(a) A test specification for monitoring of thermal expansion of piping systems shall be prepared.

(b) Prior to testing of a piping system, a pretest walkdown shall be performed to ensure that construction is sufficiently complete for thermal expansion testing. The testing program and system completion requirements shall be consistent with the applicable construction code rules (e.g., ASME BPV Code, Section III). Any exceptions to the construction completion that affect thermal expansion testing shall be evaluated and documented.

The walkdown shall also verify that the anticipated piping movement is not obstructed by objects not designed to restrain the motion of the system (including instrumentation and branch lines). The system walkdown program shall verify that supports are set in accordance with the design.

(c) Selection of the locations and the types of measurements to be made shall consider the acceptance criteria and shall reflect any unique operational characteristics of the system being tested.

(d) When test results are to be correlated to specific analyses, test conditions and measurements should be specified in sufficient detail to ensure that the parameters and assumptions used in the analyses are consistent with those in the test.

3.1 Specific Requirements

Minimum requirements for thermal expansion testing of accessible, inaccessible, and small pipe (branch lines) are outlined below.

3.1.1 Test Specification

(a) The thermal expansion design basis of the system will be considered in the development of test specification requirements, selection of instrumentation, establishment of acceptance criteria and acceptable limits, and for review, evaluation, and approval of test results.

(b) The test specification shall include, as a minimum, the following:

(1) test objectives

(2) systems to be tested (including boundaries)

(3) pretest requirements or conditions

(4) governing documents and drawings

(5) precautions

(6) quality control and assurance (including required documentation and sign-offs)

(7) acceptance criteria

(8) test conditions and hold points

(9) measurements to be made and acceptable limits (including visual observations)

(10) types of instruments to be used and minimum instrument specifications

(11) data handling and storage

(12) system restoration

(c) The test specification shall be written in a manner so as to ensure that the objectives of the test as outlined in section 3 are satisfied.

(d) In selecting locations for monitoring piping response, consideration shall be given to the maximum expected responses from the thermal expansion analysis. Locations with large expected movements should be monitored since these are convenient locations to look for general conformance of system response to analytic predictions. Specific consideration shall also be given to detecting evidence in the tests of the following:

(1) higher or lower than expected movements at the end of the first run(s) of pipe attached to component nozzles that may cause problems in stiff portions of the system that are sensitive to the thermally induced loads (e.g., rotating equipment, thin wall vessels, heat exchangers).

(2) zero or out-of-range movement of the pipe at hanger or snubber locations; snubbers and variable spring hangers provide convenient devices for measuring thermal displacements.

(3) higher or lower than expected movement of the pipe adjacent to a structure requiring a controlled gap, e.g., at pipe whip restraints.

(4) discrepant piping responses (e.g., movements, stress, support loads, resulting from thermal stratification or thermal transients); Nonmandatory Appendix B of this Part provides descriptions and examples of thermal stratification and thermal transients.

(e) The response of the system shall be checked at the test hold points defined in the test specification to verify that the system is responding as expected.

(f) Actual pipe wall temperature should be considered in the evaluation of test results. For example, pipe wall temperature should be measured at various points along the piping system to ensure that the system has attained the desired test temperature. Consideration shall be given to the equipment movements and to nonuniform temperature distribution of system (e.g., branch piping with cold legs, thermal stratification, and thermal transients in applicable lines) prior to reconciliation, or prior to extrapolation (scaling) of results from a test condition to other operating temperature modes.

(g) For selected components in each system, spring travel and snubber movement shall be monitored and compared with acceptable limits. The number of monitored components shall be sufficient to define the response of systems.

(h) The maximum test temperature shall be as close as practicable to the maximum operating temperature of the system. The thermal expansion test shall be conducted in such a way that the response to the test conditions adequately represents the response to thermal modes of operation of the system.

(i) Small pipe (branch line) shall be checked in the vicinity of its connection to large pipe or equipment to ensure that sufficient clearance and flexibility exists to accommodate thermal movements of the large pipe or equipment.

(j) When the design requires hot shimming, an additional heat-up and cooldown cycle subsequent to the hot shimming should be performed to ensure correct response of the system.

3.1.2 Accessible and Inaccessible Piping

(a) Accessible piping shall be walked down at the specified test hold points to ensure that the objectives of the test are satisfied. Visual examination and measurements during walkdown using simple devices, including spring and snubber scales, are acceptable, unless the test specification requires more sophisticated measurement methods for greater accuracy.

(b) In the case of inaccessible piping, sufficient remote instrumentation shall be used to meet the test objectives.

3.2 Acceptance Criteria

When the test temperature is other than the design basis temperature of the piping, the acceptable limits shall be adjusted for the test temperature in checking compliance with the acceptance criteria. Acceptance criteria for thermal expansion of the piping system are as follows:

(a) The pipe shall move freely, except at the locations where supports/restraints are designed to restrain pipe thermal movement.

(b) Thermal movement of pipe at the locations of all spring hangers and snubbers shall be within their allowable travel range.

(c) The thermal movement of the pipe at the preselected measurement locations shall be within the acceptable limits specified, or discrepant response shall be reconciled in accordance with section 4. Acceptable limits of thermal response shall be established to ensure that applicable code allowable stresses and allowable equipment and nozzle reactions are not exceeded. Acceptable limits of thermal response shall consider the following:

(1) design basis thermal expansion analysis

(2) test temperature

(3) variations between actual system characteristics and analytical assumptions (such as support and equipment flexibility, gaps, and friction)

4 RECONCILIATION METHODS

Discrepant responses that are detected during testing shall be reconciled and/or corrective action shall be implemented (see section 5) prior to acceptance of the test results. Reconciliation of the discrepant responses shall demonstrate that the requirements of section 3 have been met.

The discrepant responses shall be evaluated and documented in conjunction with the results of the design basis thermal expansion analysis. The analysis input parameter and assumptions shall be checked against actual system characteristics. For example, this could include

(a) actual test temperature variation along or around the pipe versus the temperature used in determining acceptable limits

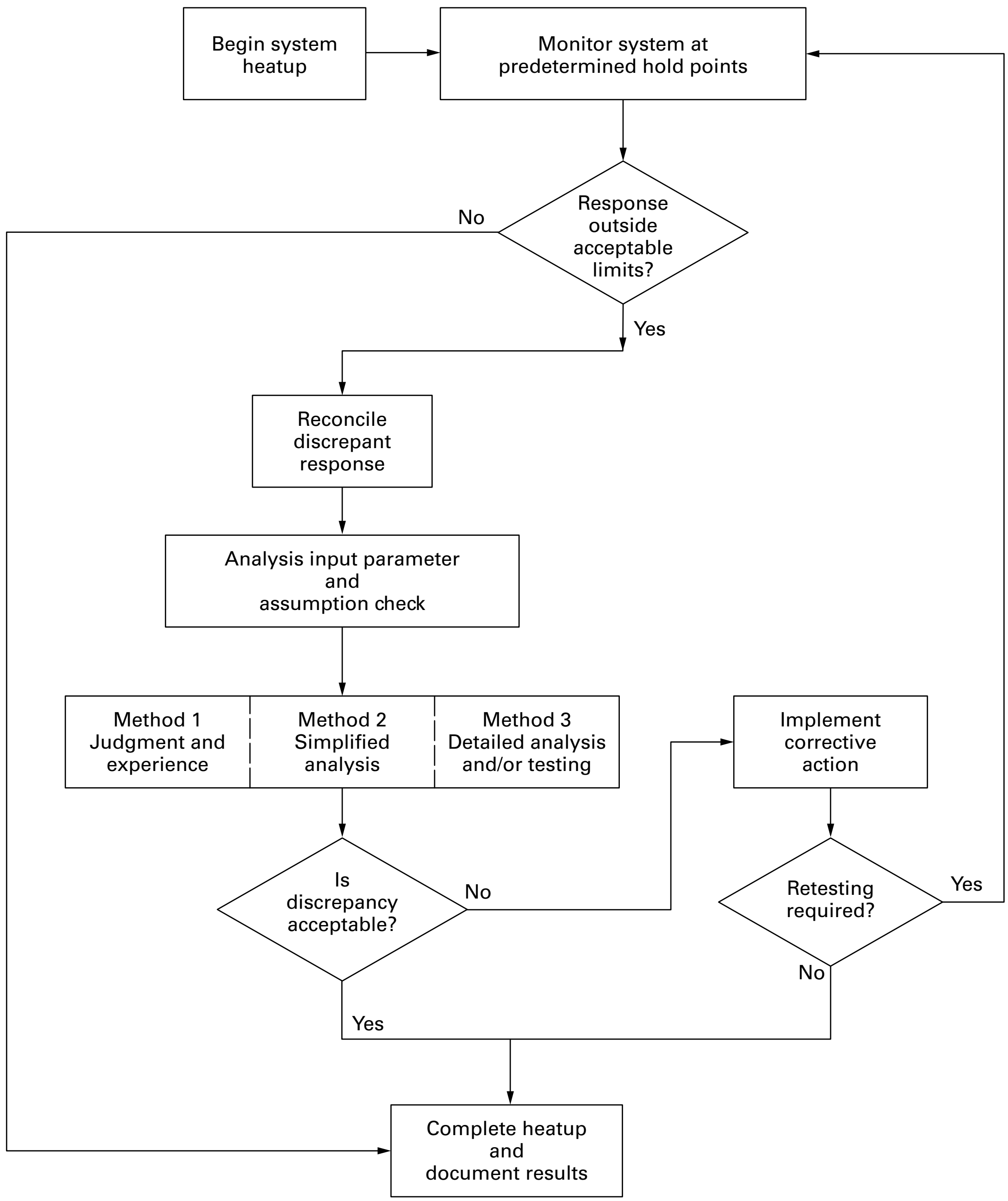
(b) actual movement of equipment nozzles (including rotation) versus that used in the analysis

(c) binding of the pipe or spring hanger pins not pulled

If the discrepant responses cannot be reconciled, then corrective action shall be performed as detailed in section 5. Figure 1 depicts the steps involved in reconciliation and corrective action.

This paragraph provides suggested methods for the reconciliation of discrepant responses. Other methods

Fig. 1 System Heatup, Reconciliation, and Corrective Action



may be used provided they conservatively predict pipe stresses and component reactions.

4.1 Reconciliation Method 1

Reconciliation of discrepant responses using this method is based on experience and documented engineering judgment. If more detailed assessments are required, Reconciliation Method 2 or 3 should be used. The basis for determining if the responses are acceptable shall be consistent with the requirements of para. 3.2.

The judgment of acceptability can be made only by evaluation and documentation of the following items as to their effect on piping stress and component reactions:

(a) applicability of assumptions made in the design basis thermal expansion analysis

(b) location and magnitude of thermal expansion stresses predicted by design basis analysis

(c) location and magnitude of discrepant responses

(d) proximity to sensitive equipment

(e) branch connection behavior

(f) capability of associated component supports

(g) unique system operational characteristics

4.2 Reconciliation Method 2

This method assesses the acceptability of the discrepant responses via simplified models of the affected segment of piping. The segment of piping affected by the discrepant responses can be modeled using appropriate simplified beam analogies. Simplified beam models are readily available in public literature. Alternatively, a simplified computer model of the affected piping segment can be used to assess the effects of the discrepant responses.

The objective of the model used is to obtain a conservative quantitative evaluation of the thermal expansion effects. One simplified model may be required to conservatively predict pipe stress, but a different simplified model(s) may be required to conservatively predict support loads on component reactions. The acceptability of the evaluation shall be based on the criteria delineated in para. 3.2.

The considerations specified in para. 4.1 are also applicable to Reconciliation Method 2.

The simplified beam or computer models suggested in this paragraph should result in conservative predictions of stresses and support and equipment loadings. Reconciliation Method 3 may be used to eliminate some of the conservatism inherent in these models.

4.3 Reconciliation Method 3

This method requires a detailed assessment of the discrepant responses. This is accomplished through the use of detailed testing and/or analysis. The objective is to obtain additional data to determine a more accurate and less conservative representation of the system. If the results of the detailed testing and/or analysis demonstrate that the system response is within the requirements of para. 3.2, then the response is acceptable.

Detailed analysis may involve incorporation of the actual measured response of the system into the design basis analytic model to obtain forces and stresses.

5 CORRECTIVE ACTION

When the discrepant responses cannot be reconciled, corrective action shall be implemented prior to acceptance of the test. The objective of corrective action is to identify and eliminate the cause of the discrepant responses or to mitigate their effects.

Possible corrective actions typically fall into the following categories:

(a) Eliminate Interference. Interference can result from thermal expansion displacements exceeding the clearances between the pipe and pipe supports, building structures or other surrounding structures, or equipment. Eliminating the interference involves complete or partial removal of the interfering structure.

(b) Modify Support System. Support malfunction, inadequate support operating ranges, or improper cold settings can result in the support interfering with the pipe expansion. Corrective action involves replacing or readjusting the supports. Supports may be replaced with supports of different operating ranges, supports of different types (for example, replace rigid with snubber), or supports with different flexibility characteristics. Additionally, supports may be eliminated to increase the system flexibility, or supports may be added to redirect the system expansion movement.

(c) Modify Pipe Routing. Corrective action may involve rerouting the piping to avoid obstructions, to redirect the expansion movement, or to increase flexibility through the addition of expansion loops.

(d) Modify Operating Procedures. Corrective action may involve modifying operating procedures, such as avoiding unnecessary injection of hot fluids into certain piping systems.

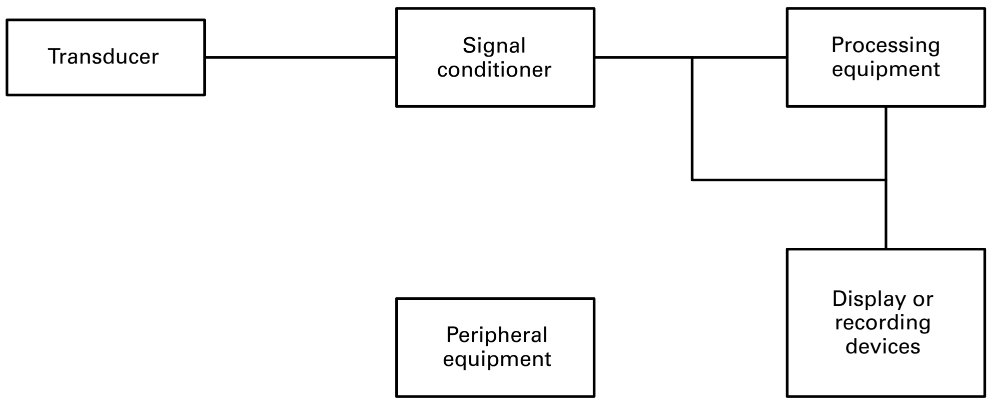
After corrective action is implemented, and if the corrective action can affect the thermal expansion response of the system, then additional testing shall be performed to determine if the system response meets the requirements of para. 3.2.

If corrective action results in hardware modifications, then the piping system design basis analysis shall be reviewed and revised, as required, to include the effects of the corrective action.

6 INSTRUMENTATION REQUIREMENTS FOR THERMAL EXPANSION MEASUREMENT

This paragraph provides requirements for the instrumentation and recording equipment necessary to meet

Fig. 2 Typical Components of a TEMS



the minimum data acquisition and reduction requirements for thermal expansion testing of piping systems. Recognizing the constant advancement of instrumentation and data acquisition equipment, this paragraph is not intended to explicitly require certain instruments or techniques. Rather, this paragraph sets forth the criteria necessary to ensure that the data taken by any method is accurate, repeatable, and within the capabilities of the method or equipment being used. A typical TEMS is shown in Fig. 2.

Nonmandatory Appendix A of this Part contains guidelines and precautions for typical TEMS. Nonmandatory Appendix A of this Part can be used as a basis for the specification of the instrumentation/measurement system to be used during testing.

6.1 General Requirements

The systems and techniques used for measuring the thermal expansion of all piping systems covered by this Part shall meet the following minimum requirements.

6.1.1 TEMS Specification. A TEMS specification shall be included in or referenced by the test specification and shall include the following:

(a) functional description.

(b) list of equipment (Manufacturer, model number, serial number).

(c) equipment calibration record.

(d) equipment specifications.

(e) installation specifications.

When visual means (such as rulers or scales) are the only methods used to measure the thermal expansion of the system, the requirement for a TEMS specification may be waived; however, the methods used shall be documented.

For the TEMS as well as each device comprising the TEMS, the information and minimum requirements listed below shall be contained in the TEMS specification when applicable. An example of the specification of the TEMS minimum requirements is given in Table 1.

Table 1 An Example of Specification of TEMS Minimum Requirements

Acceptable limit	Minimum value (D_{min}) = 1.0 in. (2.54 cm) Maximum value (D_{max}) = 1.5 in. (3.8 cm)
Accuracy	±0.1 in. (±10% of D_{min}) (±0.254 cm)
Minimum measurable value	+0.8 in. (80% of D_{min}) (+2.0 cm)
Full-scale range	+1.8 in. (120% of D_{max}) (+4.6 cm)
Stability	±0.05 in. (±5% of D_{min}) (±0.13 cm)
Frequency response	Static
Other (maximum pipe temperature)	300°F (149°C)

(f) inputs and outputs: units and full-scale range of each.

(g) accuracy: specified as a percentage of full-scale physical units.

(1) TEMS minimum requirement: ±10% of the minimum acceptable limit.

(h) minimum measurable value.

(1) TEMS minimum requirement: accurate readings from the TEMS should be obtainable when the measured variable reaches 80% of the minimum value of the acceptable limit.

(i) range: full-scale capability with accuracy specification.

(1) TEMS minimum requirement: accurate readings from the TEMS should be obtainable until the measured variable reaches 120% of the maximum value of the acceptable limit.

(j) stability: allowable variation of initial zero or reference setpoint when subsequent measurements are made with respect to that initial setpoint.

(1) TEMS minimum requirement: ±5% of the minimum acceptable limit.

(k) frequency response.

(1) TEMS minimum requirement: capable of measuring static data.

(l) calibration data: specific requirements are given in para. 6.1.2.

(m) other specifications: any other specifications unique to the measurement system or important for the accurate measurement of the variable, such as temperature compensation or mounting requirements.

Manufacturer's specifications are acceptable for each device comprising the TEMS; however, care should be exercised that the application, mounting, and interfacing conditions do not affect or invalidate the manufacturer's specifications. This is especially important in transducer mounting and electrical loadings.

6.1.2 Calibration. All equipment used as part of the TEMS shall have current calibration documents. These shall be attached to or made part of the system specifications. On-site checkout of the TEMS shall be performed to verify that the as-installed TEMS is functioning according to the system specification.

6.1.3 Repeatability. Capability of the TEMS to provide consistent results shall be demonstrated. This can be achieved by taking several consecutive measurements of a stationary variable during pretest setup and checkout. The results of these consecutive measurements should be within minimum accuracy requirements of the TEMS specification.

6.1.4 Acceptability of Measurements. Measured data is considered acceptable for evaluation with respect to acceptance criteria provided that it falls within the capability of the TEMS as prescribed by the TEMS specifications. Measurements that fall outside the TEMS capability must be remeasured using an appropriate technique.

6.2 Precautions

The requirements given above for the specifications of the TEMS represent the minimum necessary to ensure accurate measurement of thermal expansion data.

In developing these minimum requirements, it was assumed that the acceptable limits represent ranges of thermal expansion for which there is a high level of confidence that the measurements will fall within 20% of the expected ranges. Although not required, it is recommended that the TEMS be specified to have a broader capability with respect to minimum measurable value and full-scale range. This will allow the measurement of thermal expansions that are not within 20% of the acceptable limits and should minimize the amount of retesting required.

Part 7, Nonmandatory Appendix A Guidelines for the Selection of Instrumentation and Equipment of a Typical TEMS

The purpose of this Nonmandatory Appendix is to provide tables from which the user of this Part may select the components that comprise a thermal expansion measurement system. Recognizing the wide range and selection of available equipment, Tables A-1 through A-4 are not meant to be all-inclusive. Rather, they represent typical equipment in use at the time this Part was prepared.

The tables are organized with respect to the generic basic components of the TEMS as described in section 6.

For each typical device listed, information regarding such areas as function, application, and limitations is given as an aid in the selection process.

Table A-1 Typical Transducers

Device	Basic Function or Application	Precautions/Limitations
Ruler, scale	A hand-held device for direct measurement of displacement from a fixed reference, read visually at location of measurement	Requires personnel at measurement location Limited accuracy of $\frac{1}{16}$ in. (1.6 mm)
Dial indicator	A mechanical device mounted to a fixed reference point at the measurement location, displacement visually read by dial and pointer	Very good accuracy, but typically a function of range Must be securely mounted Zero setting very sensitive to mounting stability
Lanyard	An electromechanical device consisting of a cable, spring, and resistive potentiometer that provides an electrical signal proportional to the displacement of the cable end	Accurate, stable, and easily mounted Provides for centralized monitoring of many points Signal conditioners required
LVDT	An electromechanical device that produces an electrical output proportional to the motion of a magnetic core inside three coils	Provides high accuracy and resolution Loading of test object is minimal since only the core is attached to the moving object Requires signal conditioning with AC excitation More fragile than lanyard transducers
Proximity probe	An electrical eddy current device that produces an electrical output proportional to the gap between the probe and the monitored object	Linear range is limited to variations about the initial gap Requires power supply and proximitor Provides high accuracy and resolution
Thermocouple	An electrical device that produces a voltage proportional to the difference in temperature between two junctions of dissimilar metals	Readily available in a variety of configurations Rugged, easily mounted Provides for centralized monitoring of many points Requires use of a reference junction Voltage output is not linear with respect to temperature
RTD	A resistance temperature detector that changes the resistance of the sensing element proportions to its temperature	Readily available, easily mounted Provides centralized monitoring of many points Does not require use of a reference junction Not as rugged as thermocouples Resistance change is not linear over a wide temperature range May be prone to self-heating effects if continuously excited
Strain gage	An electrical device that measures surface deformation of the test object. The most common type uses the change in resistance of a foil or wire grid intimately bonded to the surface of the test object to indicate the average strain over the grid length.	Provides actual strains in the piping instead of displacements High temperature use may require welding or post-curing of adhesives Temperature compensation, long-term stability, and hysteresis effects may be sources of problems

Table A-2 Typical Signal Conditioners

Device	Basic Function or Application	Precautions/Limitations
DC amplifier	Electronic device used to amplify the signals supplied by lanyards, LVDTs, thermocouples, strain gages, etc.	Provides high level signals for ease of reading or recording Gains must be recorded for units with switchable gain settings Units for static measurements should have minimal zero drift
Power supply	Provides constant power signal to LVDTs, proximity probes, strain gages, and lanyards for signal generation	May provide either AC or DC power in accordance with transducer requirements Power regulation must be within either transducer manufacturer's specifications or within system accuracy requirements Total transducer loading on the power supply must not exceed rated capacity
Reference junction	Provides or simulates a known temperature at one junction of a thermocouple, so that absolute temperature at the other junction may be found	Some reference junctions are made for specific types of thermocouples. They may be used only with that type. Since reference junctions will often be used near the measurement location, care must be used to ensure that the ambient temperature does not exceed the equipment capabilities

Table A-3 Typical Processing Equipment

Device	Basic Function or Application	Precautions/Limitations
Data logger	Provides analog to digital conversion of transducer or signal conditioner output; automatically scans, processes, and records multiple channels of data	Processing capabilities may require computer controls. Output capabilities may require a computer interface.
Minicomputer	Provides control, processing, storage, and output functions when used with a data logger or analog to digital converter	Has greatly expanded processing and output capabilities compared to a data logger Requires much time for setup and programming of a new system
Voltmeter	Can be used to measure voltage or resistance of electrical circuits	Slow device — requires manually repositioning probes for each reading Requires manual recording and processing of data

Table A-4 Typical Display/Recording Equipment

Device	Basic Function or Application	Precautions/Limitations
Tables and graphs	Printed material in appropriate format to manually log test data and measured values	Manual logging of data will be a time-consuming process in comparison with automated procedures
Strip charts	Continuous time history plots produced by a mechanical recorder	These are only practical for a relatively small number of channels in comparison to data loggers or minicomputers
Oscilloscope	A device to display an electrical signal in graphical form upon the screen of a cathode-ray tube	Due to the time limitations upon the display, it will only be useful for rapidly occurring events Oscilloscopes typically do not produce permanent records
Printed tables	The paper output produced by data loggers or minicomputers that contains data printed out in numerical form	Large volumes of output may be produced
Analog or digital tape recorder	A device to store/replay information using varying local magnetization of a moving strip of plastic that has been coated with a metallic material	Useful for storing large amounts of data in a compact form Retrieval of the data requires use of equipment similar to that used for recording

Part 7, Nonmandatory Appendix B Thermal Stratification and Thermal Transients

B-1 INTRODUCTION

Thermal conditions may occur in piping systems that could result in high internal forces and moments causing piping or support damage. This Nonmandatory Appendix describes thermal stratification and valve leakage conditions that have occurred in nuclear power plants and have caused anomalous system response or piping and support damage. It is the intent of this Nonmandatory Appendix to describe several occurrences to assist in root-cause evaluations.

B-2 THERMAL STRATIFICATION

Thermal stratification is a phenomenon that can occur in any stagnant or low-velocity single-phase fluid or stratified two-phase flow. It can be caused by low flow rates into a pipe containing different temperature fluid. It manifests itself as a nonlinear temperature gradient occurring predominantly in horizontal sections of pipe (see Fig. B-1). The phenomenon occurs when hotter (less dense) fluid floats on top of cooler (more dense) fluid. This tendency to separate is caused by the buoyancy or density differences of the two fluids. Under nonturbulent, low-velocity flow, the two fluid layers do not have time to achieve a steady-state homogeneous temperature profile and tend to remain separated. However, under high flow rates, the fluid flow becomes turbulent, which promotes mixing of the two fluid layers, resulting in a homogeneous temperature profile.

The temperature profile typically manifests itself as two volumes of almost constant but different temperatures separated by a relatively small temperature transition zone. Measurements have been made in some fluid systems indicating difference in temperatures as high as 320°F (178°C). Higher differences are also possible. During other operating modes, the same system exhibited temperature differences between 0°F (−18°C) and 100°F (38°C).

Thermal stratification has been observed in PWR surge lines. The surge line connects the reactor coolant loop (RCL) with the pressurizer. The pressurizer is typically at a higher temperature than the RCL since it contains electric heating elements that maintain the fluids at saturated conditions. Under startup (steam bubble formation) and normal operating conditions, fluid temperature inside the pressurizer ranges between 400°F (204°C) and 650°F (343°C), while the RCL temperature typically varies between 120°F (49°C) and 615°F (324°C). It is this large difference in temperature between the pressurizer and the RCL that provides the difference in temperature of the fluid in the surge line. Fluid is exchanged between the pressurizer and the RCL as the system maintains the desired pressure using heaters and spray. As the RCL fluid temperature increases, the RCL fluid volume increases, causing an insurge of fluid into the pressurizer; at the same time, some of the hotter fluid flows out of the pressurizer to heat the reactor coolant system (RCS). These flows are generally slow and laminar, resulting in conditions conducive to thermal stratification. During conditions of high flow in the surge line (caused by reactor coolant pump start/stop, rapid boron injection, or activation of the pressurizer spray valves), the high velocities tend to mix the fluids, creating a homogeneous thermal condition. However, upon return to normal flow in the surge line, the fluids again return to a stratified flow condition.

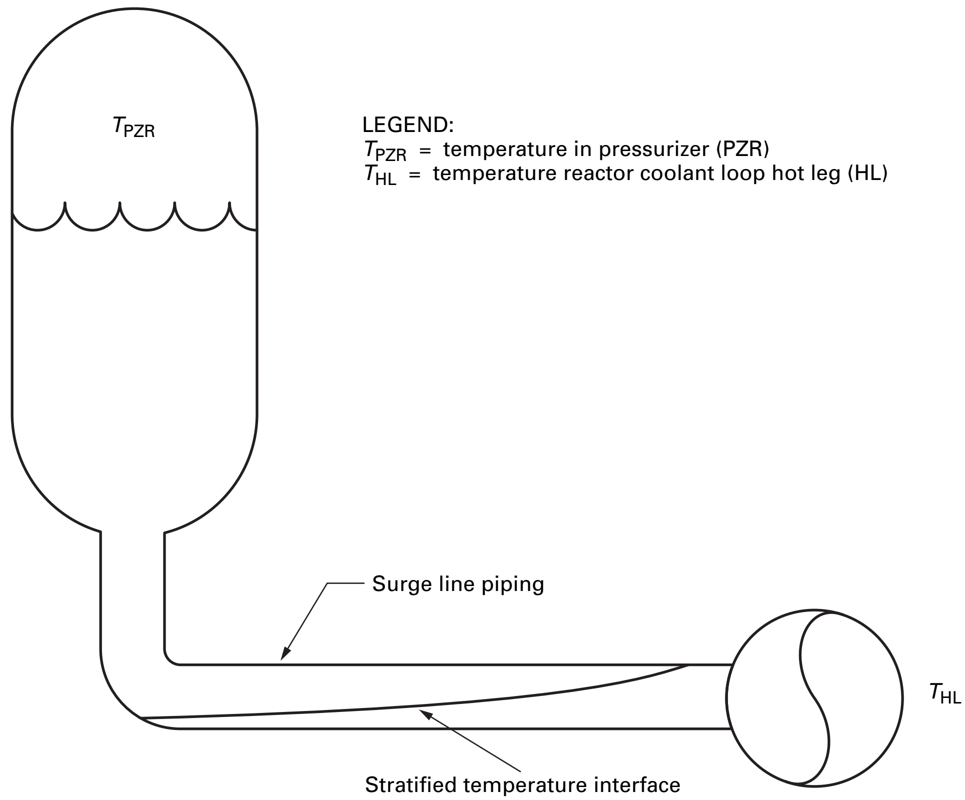
The differences in temperatures cause the pipes to assume a circumferential temperature gradient. This gradient causes the pipe to bow, typically in the vertical plane. This vertical bowing can create unanticipated internal forces and horizontal or vertical movement in a complex three-dimensional piping system. This unanticipated movement could result in unintentional restraint of the piping system (e.g., gaps on rigid restraints close, snubber movements exceed allowable limits, or pipe contacting pipe rupture restraints).

The stratification phenomenon depends on piping system geometries. Valves, elbows, reducers, and orifices tend to create turbulence in the flow steam and, thus, could reduce the severity of stratification.

In some PWR designs, the auxiliary feedwater (AFW) system supplies fluid to the steam generator via main feedwater (MFW) piping. The MFW and AFW systems have also been reported to exhibit thermal stratification under certain operating modes and system alignment. The MFW contains larger pipe sizes and higher temperature fluid than the AFW piping system.

When flow in the MFW system ceases and AFW is initiated, cooler AFW fluid is injected into the larger, hotter MFW piping, which is at a higher temperature. Due to the large difference in pipe size, the velocity of the AFW fluid in the larger MFW line is significantly reduced. The large difference in temperature coupled with the greatly reduced flow rate are conditions that could result in stratified flow.

Fig. B-1 Simplified Schematic of Surge Line Stratification



Other systems in which flow stratification has been reported are pressurizer spray systems, reactor core isolation cooling systems, and reactor water cleanup systems.

Striping is a phenomenon associated with thermal stratification and has been shown, in cases investigated thus far, to be an insignificant factor in causing fatigue damage to piping systems. Striping is a phenomenon where two fluids at different temperatures are separated by an interface that tends to oscillate about its equilibrium condition. This oscillation causes alternating heating and cooling of a region of the pipe that can theoretically lead to fatigue damage.

B-3 THERMAL TRANSIENTS

The majority of thermal transient conditions are anticipated and included in the analysis of ASME piping systems. Occasionally, new transients are discovered or defined. Some of these are due to changes in operating conditions, the addition of new systems, or discovery of new phenomena.

In other cases, the malfunction of a component, such as a valve, can result in leakage between two normally isolated sections of a piping system. These two normally isolated sections can contain fluids at different temperatures and pressures. The differential pressure creates a driving head that causes fluid flow. The injection of fluid at temperature into a section of pipe containing fluid at a different temperature will initially cause a thermal stress cycle in the pipe.

If the leakage is constant, stress reversals will occur only during plant/system startups and shutdowns, resulting in a relatively few number of stress cycles and, therefore, no significant increase in the fatigue cumulative usage factor. However, if the leakage occurs intermittently, a fatigue crack can be initiated, propagated, and can potentially cause a breach in the pressure boundary. Such intermittent flows can occur, for example, when a normally closed valve leaks and causes a change in the temperature of the valve disk. The change in temperature of the valve disk can cause thermal growth of the disk and resealing of the flow path. Upon cessation of the flow, the separated sections tend to return to the thermal conditions that existed when the leak initiated. Repetition of this sequence could occur frequently, and with sufficiently high temperature differences could result in large numbers of stress cycles and possible thermal fatigue damage of the pipe. It is difficult to determine, without monitoring, whether a leak is continuous or intermittent.

(a) Three conditions must be present to create this condition, as follows:

(1) leakage by the valve seat

(2) pressure differences across the valve seat

(3) temperature difference on both sides of the valve seat

(b) Such low leakage rates can easily go undetected. There are several techniques available that may detect leakage past a valve seat, such as

(1) visual inspection (intrusive)

(2) acoustic monitoring (nonintrusive)

(3) temperature monitoring

Part 11
Vibration Testing and Assessment of Heat Exchangers

1 INTRODUCTION

1.1 Scope

This Part provides guidance for preservice and inservice testing to assess the vibration of certain heat exchangers used in light-water reactor (LWR) power plants. The heat exchangers covered are those required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident. This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

acceptance criteria: criteria that establish whether or not further investigation or follow-up actions are needed based on results of the vibration assessment.

conditions: primary and secondary fluid temperatures, pressures, and flow rates; settings of valves in piping adjacent to the heat exchanger.

first of a kind: a heat exchanger having a design, operating condition, or installation that differs significantly from heat exchangers that have been tested or that have an adequate operating experience.

flow rate plateau: a flow rate at which steady-state conditions are maintained and data are acquired.

normal operating conditions: the service conditions a heat exchanger would experience when performing its intended function.

operating limitations: limitations on heat exchanger operating conditions to prevent unacceptable vibrations.

Owner: the organization legally responsible for the construction, or operation, or both, of a nuclear facility including but not limited to one who has applied for, or who has been granted, a construction permit or operating license by the regulatory authority having lawful jurisdiction.

shell-side flow: the flow in passages between the outside of the heat exchanger tubes and the inside of the shell.

steady state: the state in which conditions do not change with time and during which initial transients or fluctuations have disappeared.

tube-side flow: the flow inside the heat exchanger tubes.

NOTE: Definition of wave analysis terms such as *power spectral density, cross-power spectral density,* and *coherence* can be found in the reference of subpara. 3(a).

3 REFERENCES

The following is a list of publications referenced in this Part:

(a) ANSI S2.10-1971, Methods for Analysis and Presentation of Shock and Vibration Data; Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036 (www.ansi.org)

(b) M. K. Au-Yang and K. P. Maynard, "Guidelines for the Reduction of Random Modal Test Data," Proceedings of the 3rd International Modal Analysis Conference, Orlando, FL, Vol. 1; Publisher: Union College Press, 807 Union Street, Schenectady, NY 12308

4 BACKGROUND DESCRIPTION

Heat exchangers of various types and service requirements are used extensively in nuclear power plants. As examples, a typical boiling water reactor (BWR) plant may have as many as 30 heat exchangers while a pressurized water reactor (PWR) plant may have between 50 and 60 heat exchangers. These heat exchangers can range in size from a 2 gpm (126 cm^3/h) ten-tube distillate cooler to a 58,200 tube condenser and can include straight, U-tube, coil, and hairpin configurations. The various shell-side fluids include air, steam, water, glycol, hydrogen, and oils. In general, heat exchangers that can directly affect the operability or safety, or both, of the plant are the units of most concern. These include, for example, steam generators with primary coolant on the tube side, feedwater heaters, condensers, and residual heat removal heat exchangers.

There is a history of tube vibration problems in shell-and-tube heat exchangers used in the power and process industries. For the most part, the tube vibration is induced by the shell-side cross-flow, which represents a source of energy that can excite and sustain vibration. The mechanisms responsible for exciting tube vibration are addressed in Nonmandatory Appendix A of this Part.

While a tube bundle vibration analysis will provide important design guidance, available information and experience to support assumptions in the analysis may not allow for sufficiently accurate prediction of actual vibration behavior. Therefore, a program of vibration measurement is often needed to determine whether vibration levels are acceptable.

The intent of the vibration assessment in this Part is to minimize impact on plant operation by early identification of excessive vibration levels. The primary application is for first-of-a-kind heat exchanger designs. Other applications would be for heat exchanger designs suspected to be susceptible to excessive vibration based on the following:

(a) operating experience of similar units

(b) design calculations

(c) a need to operate the heat exchanger at higher flow rates

This Part can also be applied to evaluate the effectiveness of modifications.

5 SELECTION OF EQUIPMENT TO BE TESTED

5.1 Equipment Selection Factors

Factors to be considered in establishing the need for a test and in selecting the type of measurement shall include at least the following:

(a) the importance of the heat exchanger

(b) previous operational experience with a similar design

(c) available design analysis and laboratory test data

(d) equipment configuration

5.1.1 A large nuclear steam generator of essentially new design, the failure of which may cause major impact on plant operation, shall be tested by the Direct Method (see paras. 6.1 and 7.1). Prior test results and operational experience may be used (in lieu of new tests) to demonstrate the adequacy of a heat exchanger under the following conditions:

(a) The design of the heat exchanger under consideration is "sufficiently similar" to a reference design (prototype) with proven structural integrity to permit a comparative flow-induced vibration analysis, using the reference design as the basis.

The following factors shall be considered to establish that a new design is sufficiently similar to the reference design:

(1) geometries, size, materials, and fabrication processes

(2) shell-side and tube-side fluid velocity and density distribution

(3) environmental conditions such as temperature, pressure, and water chemistry

(b) A comparative analysis shows that the heat exchanger under consideration is no more susceptible to fluidelastic instability, turbulence, and vortex-induced vibration than the reference design and, consequently, is subject to no more flow-induced wear and fatigue than the reference design.

A comparative flow-induced vibration analysis is one in which the empirical input parameters in the vibration prediction equations are common to, or can be simply extrapolated from, those of the reference design. The new design is "sufficiently similar" to the reference design if the factors in subparas. (a)(1) through (a)(3) do not invalidate these simple extrapolations. Nonmandatory Appendix B of this Part includes correlations that may be used in lieu of more specific information.

5.1.2 For steam generators or other heat exchanger designs that are similar to a reference design in accordance with subparas. 5.1.1(a)(1) through 5.1.1(a)(3), but have some geometry or flow differences that do not significantly change the flow distribution in the heat exchanger or tube support conditions and probabilities, an in-plant tube vibration measurement program is not required if the following apply:

(a) Prior test results and operational experience on unit(s) exhibiting no unacceptable tube wear over extended time are available for the reference design.

(b) Analysis results for the design under consideration show that the margins for fluidelastic instability, turbulence, and vortex-induced vibration are adequate to accommodate uncertainties in the analysis and uncertainties in criteria established from laboratory testing, plant testing, and experience.

(c) The laboratory tests are shown to be applicable to the operating conditions of the steam generator or heat exchanger.

It is suggested that the Owner review the planned or available laboratory tests; plant test results; and experience, analysis, and criteria and agree that these are sufficient to demonstrate the adequacy of the design under consideration.

5.1.3 Examples of differences that might be shown to be acceptable according to subparas. 5.1.2(a) through 5.1.2(c) are as follows:

(a) changes in tube support bundle pitch or pattern, where the fluidelastic stability constant for the design under consideration has been established by laboratory testing

(b) changes in tube support spacing or hole geometry without a significant increase in clearance at the tube support

(c) modest flow increases, such as the increases associated with power upratings

System (piping and valve configurations) and heat exchanger supports should be similar if previous experience is to be applied. Changes in the fluid system or heat exchanger supports could result in flow imbalance or tube support motions that are reflected in tube vibration.

For some heat exchanger designs, mechanical testing to determine dynamic characteristics of tubes may support the similarity of subsequently manufactured units to a flow-tested unit. Guidelines for conducting these tests are provided in Nonmandatory Appendix C of this Part.

6 SELECTION OF TEST METHOD

6.1 Test Measurement Methods

There are three types of measurement methods to consider. In order of increasing complexity, time, and cost of application, the methods are as follows:

(a) External Monitoring for Impacting. Impact detection from signals of accelerometers mounted on the exterior surfaces of the heat exchanger.

(b) Microphone Scan to Detect Impacting. Impact detection from signals of microphones installed at the tube ends.

(c) Direct Measurement of Tube Response. Measurement of tube response by transducers mounted on or adjacent to individual tubes.

6.1.1 Impacting is considered to include metal-to-metal contact between heat exchanger component pairs that has the potential to cause failure by wear. Component pairs include the following:

(a) adjacent tubes

(b) tubes and tube support plates

(c) auxiliary components, such as tie-rods and shell

6.1.2 The implementation of each of these measurement methods and guidelines for evaluation and interpretation of the results are provided in section 7. The information obtained from each test method and their limitations are summarized.

(a) External Monitoring for Impacting. This method can do the following:

(1) detect the presence of severe tube vibration

(2) identify the threshold shell-side flow rate for impacting or determine that impacting does not occur for flow rates up to an established (design, operating, or test) flow rate limit

(3) provide a basis for establishing acceptable shell-side operating flow rate limits

(4) provide a criterion to determine the need for additional, more-detailed tests (e.g., microphone scan and/or direct measurement), or structural modifications

(5) in some cases, indicate the general location of impacting

(6) be limited as follows:

(-a) Impacts may not be adequately detectable for determination of the flow rate at which impacting occurs by external accelerometers.

(-b) The particular tubes or number of tubes that are impacting cannot be identified for further investigation of specific tubes.

(-c) Quantitative information, as provided by the direct measurement method, is not obtained.

(b) Microphone Scan to Detect Impacting. This method can do the following:

(1) identify the threshold shell-side flow rate for impacting or determine that impacting does not occur for flow rates up to an established (design, operating, or test) flow rate limit

(2) identify the number and specific location of impacting tubes

(3) provide a basis for establishing an acceptable shell-side operating flow rate limit

(4) provide a basis for deciding if more direct measurements (using the method outlined in para. 7.1) or remedial actions are required

(5) identify specific tubes to be instrumented for direct measurement of tube response

(6) in some cases, provide an approximate indication of the relative severity of impacts of various tubes

(7) be limited as follows:

(-a) This method cannot provide detailed quantitative data such as can be acquired by direct measurement with in-tube probes.

(-b) The tube sheet must be accessible during testing.

(c) Direct Measurement of Tube Response. This method can provide vibration response amplitude and frequency information for specific tubes. It provides the best basis for assessing the potential for vibration-induced wear or fatigue.

The limitation of this method is that replacement of failed transducers and instrumentation of a large number of tubes is impractical for some configurations.

6.2 Bases for Selection

The direct measurement method is the only method that provides quantitative information on tube response. Information for both impacting and nonimpacting tube vibration for evaluation of tube fatigue and wear is obtained from the direct measurement method. Primary system steam generators and other heat exchangers considered to be critical to the operation of the plant shall be tested by the direct method.

The direct measurement method shall also be applied to heat exchangers, for which the following applies:

(a) Information to evaluate fatigue is required.

(b) Simpler measurements cannot be applied or interpreted.

For many heat exchangers, depending on the availability of pertinent supporting information, application of either or both of the impact detection methods, with no indication of impacting or with identification of a threshold flow rate for impacting that does not limit operation, may be considered adequate for vibration assessment.

If only external monitoring for impacting is used, adequate detection of impacts by externally mounted accelerometers shall be demonstrated for the heat exchanger under consideration. Impact detection is limited by impact amplitude, transmission path, and background noise level.

If impacting is detected within the operating limits of the shell-side flow rate by one of the impact detection methods, and the heat exchanger cannot be operated at the required reduced flow rate, further action is required. In such cases, structural modifications to increase the operating limit may be implemented or the direct measurement method may be applied to obtain further information on the source and location of the impacting to provide the basis for corrective action.

6.3 Precautions

Potentially damaging vibration can exist without generating metal-to-metal impact noise. The only way to guard against this possibility is to measure the tube vibration directly (e.g., with an in-tube vibration probe or other tube-mounted sensors). As indicated in para. 6.2, the direct measurement method shall be used for steam generators. In most cases, such an elaborate test will not be justified. However, for exchangers considered marginal in design, or highly critical to production or safety, such direct measurements or their equivalent shall be specified or available from other testing.

Experience has shown that detected impacting is not always related to tube vibration. As an example, tie-rods have been known to experience vibration and to impact with the shell. In such a case, reducing shell-side flow rate accordingly may not be appropriate if the situation can be easily corrected by strengthening the tie-rod. This is a concern when basing action on the results of only the external monitoring method.

External vibration surveys to assess externally generated sources of tube excitation such as floor vibration may, in conjunction with other tests, be useful in the determination or elimination of potential vibration sources. External surveys are discussed in Nonmandatory Appendix D of this Part.

7 TEST REQUIREMENTS

7.1 Direct Measurement of Tube Vibration

7.1.1 Introduction. Data from direct measurement of tube vibration are used to do the following:

(a) identify tubes or tube bundle regions having high vibration levels

(b) establish vibration levels as a function of flow rate

(c) detect the occurrence and variation of impacting of a tube or tubes with adjacent tubes or supports as a function of flow rate

(d) detect the onset of fluidelastic vibration

(e) identify vibration modes, and in some cases, the source of excitation

(f) provide a database for evaluation of fatigue and, if appropriate, for subsequent detailed wear evaluations

7.1.2 Tube Selection. The selection of tubes to be instrumented shall be based on the following:

(a) experience with similar units with consideration for design differences

(b) calculations, review of design information, and/or relevant model tests to determine tube locations that are anticipated to become unstable first as shell-side flow is increased

(c) tubes susceptible to high-level turbulence excitation

Where possible, an acoustic survey of the tube ends at the tube sheet (see para. 7.2) should be conducted to identify those tubes that are vibrating at amplitudes sufficiently large to cause impacting within the tube support plate hole or impacting with one another.

7.1.2.1 The determination of tubes that are likely to be more susceptible to fluidelastic instability and turbulence excitation, or both, shall include consideration of design features that can result in high velocity and/or turbulence regions. These include the following:

(a) the size and location of inlet nozzle

(b) the type and size of impingement plates

(c) baffle-type, cut, and spacing

(d) leakage paths between the shell and tube bundle, between the shell and baffles, and through tube-to-tube support plate clearances

7.1.2.2 In particular, regions of concern include the following:

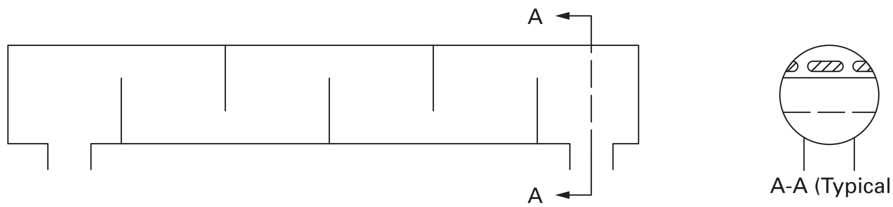
(a) tubes with long unsupported spans

(b) tube rows adjacent to a baffle cut

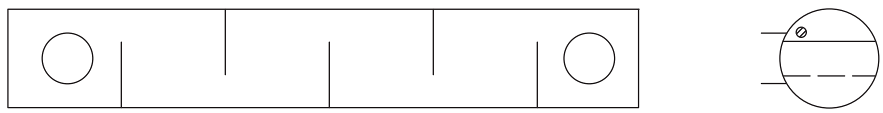
(c) tubes subjected to high local flow velocities or highly turbulent flow (e.g., tubes beneath the inlet nozzle)

For fluidelastic instability, information from detailed tube vibration flow tests of an industrial size shell-and-tube exchanger with segmental baffles are available (see Nonmandatory Appendix E of this Part). The results of these tests provide useful guidelines for the selection of tubes to be considered for instrumentation in a heat exchanger tube vibration assessment program. In particular, in Fig. 1, various tube bundle configurations that have been tested are shown together with bundle cross sections denoting the tube groupings, relative to locations of the baffle cuts, most susceptible to fluidelastic instability. An examination of the various cases shown in Fig. 1 reveals that the tubes with the longest spans exposed to high cross-flow velocities are most susceptible to vibration. If a particular tube bundle design is similar to one of the design cases shown in Fig. 1, it is recommended that tubes from the groupings

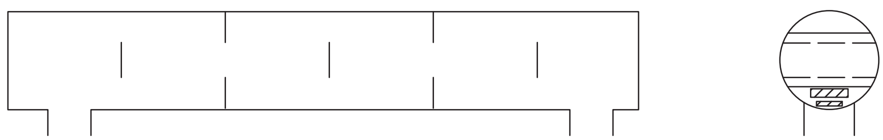
Fig. 1 Tube Bundle Configuration With Tube Groupings Most Susceptible to Fluidelastic Instability Denoted by Cross-Hatching



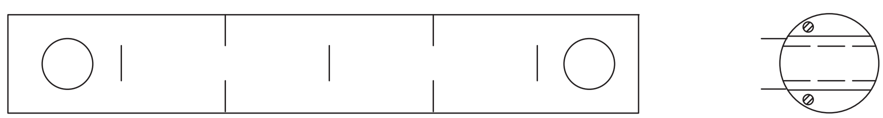
(a) Single-Segmental, Transverse-Cut Baffles



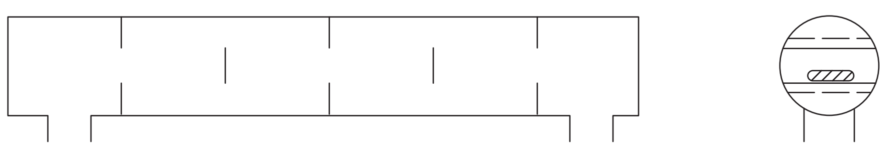
(b) Single-Segmental, Parallel-Cut Baffles



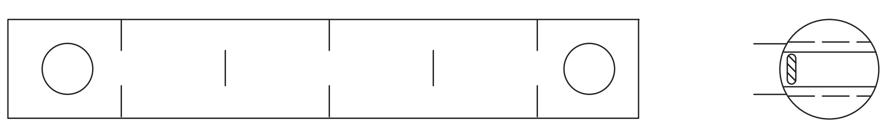
(c) Double-Segmental, Transverse-Cut Baffles



(d) Double-Segmental, Parallel-Cut Baffles



(e) Double-Segmental, Transverse-Cut Baffles



(f) Double-Segmental, Parallel-Cut Baffles

indicated in the appropriate sketch in Fig. 1 be included in those chosen to be instrumented in a vibration monitoring program.

As a precaution, it should be noted that the heat exchanger flow tests have also shown that the tube rows directly exposed to inlet nozzle flow often experience significant excitation in a higher mode (e.g., fifth mode). In such cases, the vibration frequency is high and, while the displacement levels may be low, the velocity and/or acceleration levels can be high. Since tube wear at the tube-baffle interface is a concern, consideration should be given to instrumenting tubes in this region as well.

The primary tube locations that should be considered in the evaluation of vortex shedding are those locations that experience single-phase flow and are on the periphery of the bundle or adjacent to tube lanes or adjacent to other open areas.

7.1.3 Sensor Selection. Piezoelectric accelerometers are the most adaptable sensors because they are available in the miniature sizes and light weights required for heat exchanger testing. Piezoresistive accelerometers may be used for some tests. Piezoresistive accelerometers have a wide frequency response extending to zero frequency, but are typically limited to a maximum operating temperature of less than 200°F (93°C). Accelerometers are very suitable for the detection of metal-to-metal impacting. Strain gages and displacement transducers provide better low frequency (less than 10 Hz) information than do accelerometers.

(a) Accelerometers should be installed to measure vibration in two orthogonal directions in a plane that is perpendicular to the tube centerline. The accelerometers should be positioned axially within a heat exchanger tube at a point that will result in sufficiently large acceleration signals for all modes of interest. Calculations should be used to determine this point. The calculation should be sufficiently detailed to account for multiple bending modes. When it is possible to do so, preliminary testing (moving an accelerometer axially within a tube) may be used to determine the optimal location or to verify calculations. Moving an accelerometer axially within a tube or use of multiple accelerometers is needed to determine the mode shapes of the tube vibration.

(1) Accelerometer selection shall be determined by the following factors:

(-a) temperature, chemistry, radiation, and humidity (or pressure, if underwater)

(-b) mounted natural frequencies

(-c) sensitivity

(-d) size

The effect of dissolved gases on sensor life shall be evaluated. Mounted natural frequencies should be at least a factor of three and preferably five greater than the highest modal frequency anticipated to be significant. The mounted natural frequencies shall be determined by calculation or by testing. The sensitivity of piezoelectric accelerometers should be greater than 10 pc/g. Miniature accelerometers, which may be required for some applications, are acceptable but may have sensitivities less than 10 pc/g. Low sensitivity could impair detection of low acceleration responses.

Biaxial accelerometers should be used. If two single axis accelerometers are used, the effects of the separation of the accelerometers should be considered. The accelerometers used shall be tested immediately prior to mounting to ensure operability and must be handled with care in the installation process.

(2) Cables frequently require more consideration than the accelerometer. The following requirements shall be met:

(-a) Cables must be restrained and protected to prevent chafing, fretting, and noise generated by cable whip.

(-b) Metal-sheated cables with a mineral oxide dielectric shall be used when temperatures exceed 500°F (260°C).

(-c) Low-noise (treated) cables designed specifically for accelerometer applications shall be used.

(-d) The cable length recommended by the signal conditioner manufacturer shall not be exceeded.

(3) Signal conditioners specifically designed for application with the test accelerometer shall be used. The following shall be considered in the selection of signal conditioning instrumentation:

(-a) Remote charge converters or preamplifiers shall be used for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 100 ft (30 m) and should be considered when cable runs exceed 25 ft (7.6 m).

(-b) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(-c) The signal conditioner shall have multiple gain ranges to allow maximum amplification without signal distortion.

(-d) The signals should be filtered to minimize the effects of sensor resonance, except when impacts are to be detected.

(b) Strain gages may be used to supplement accelerometer data or in some cases may be more suitable for the necessary measurements. Additionally, strain gages can be used to determine axial preload or axial loading during thermal changes. In application, the following shall be considered:

(1) Strain gages shall be mounted in orthogonal pairs.

(2) Axial position shall be in the region of maximum bending, typically at the tube sheet.

(3) The axes of sensitivity of the gages shall be aligned with the tube axis.

(4) Three gages at a single axial location are required when axial and bending loads are measured. Four gages at a single cross section are suggested for redundancy.

(-a) Strain gage selection shall be determined by the following factors:

(-1) temperature, chemistry, radiation, and humidity (or pressure, if underwater)

(-2) sensitivity of the strain gage shall be suitable for measuring anticipated loads calculated by material, clearance, and span lengths

(-b) Strain gages have been successfully cemented and welded inside heat exchanger tubes; however, mounting is an extremely delicate process and has been limited by tooling constraints to depths of approximately 24 in. (600 mm) from the tube end. Nonmandatory Appendix G of this Part contains information on strain gage mounting; as a minimum, the following shall be considered:

(-1) Gage integrity shall be checked both before and after installation.

(-2) The inner tube surface shall be prepared for strain gage installation.

(-3) Gage position shall be accurately and completely documented.

(-c) In addition, the following should be considered:

(-1) redundant gages

(-2) thermocouples installed at the strain gage location so that the data can be properly temperature compensated

(-3) if mean strains are to be acquired, the gages, after mounting, should be subjected to at least one temperature cycle before test data are acquired

(-4) lead wire resistance and length of sheath should be measured so that the gage sensitivity may be known accurately

(-d) Strain gage cables are subject to damage, and the following considerations and precautions shall be taken:

(-1) During installation excessive bending or pulling of the strain gage cable shall be avoided.

(-2) After installation cables shall be restrained to prevent chafing, fretting, or separation from the strain gage.

(-3) Metal-sheathed cables with a mineral oxide dielectric shall be used when temperatures exceed 500°F (260°C) (a breach in the outer sheath may result in cable failure).

(-e) Strain gage amplifiers shall be used in accordance with the following:

(-1) Each strain gage signal shall be individually connected to separate amplifiers (i.e., quarter bridges).

(-2) Signal conditioners shall have provisions for balancing the gage and for sensitivity compensation.

(-3) The signal conditioners shall have multiple gain ranges to prevent signal over or under range.

(-4) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(c) Noncontacting displacement transducers (or proximity probes) can be used to measure tube motion in the tube bundle periphery. Such transducers should be located at the point of maximum displacement as determined by calculation or measurement. Noncontacting displacement transducer selection shall be determined by the following:

(1) The transducer shall be rated for the temperature, chemistry, radiation, and humidity (or pressure, if underwater) condition to be encountered in testing.

(2) The transducer shall be calibrated (or compensation curves provided) for the tube (target) material.

(3) The transducer tip size shall be such that the eddy field is primarily unaffected by lateral tube motion and tube geometry.

(4) The transducer design shall be such that the eddy field is unaffected by tubes adjacent to bounding the target tube.

(5) The transducer design shall allow it to be used without modifying the heat exchanger tube properties being evaluated.

Two noncontacting displacement transducers separated by a known angle and targeted on the same tube should be used so that the orbital tube motion can be determined. The transducer shall be mounted so that heat exchanger components other than the targeted tube do not influence the measurement.

The transducer cable must be adequately restrained to prevent failure due to flow turbulence if encountered and to prevent heat exchanger damage if fluid flow is present.

The noncontacting transducer shall be powered and the signal conditioned as recommended by the manufacturer.

7.1.4 Data Acquisition. Details of data acquisition and reduction can be found in the reference in section 3 (see para. 7.1.5). A summary of guidelines to be observed is provided here.

In comprehensive or complex tests, the data will be recorded for off-line analysis. If analog tape recorders are used, they shall be Inter-Range Instrumentation Group (IRIG) compatible, with a 1 in. (25.4 mm) tape recommended. Data shall be recorded in either FM (frequency-modulated) Wide-Band Group I or Intermediate Band. The recording speed shall be selected to ensure frequency response greater than the highest vibration mode to be observed or to ensure recording of impacts, depending on the purpose of the record. If digital records are used, the sampling rate should be set at least 2.3 times the maximum frequency of interest, F_{max}. Also, the signal should be low-passed filtered before recording as per subpara. 7.1.5(d). For example, with a 48 dB/octave filter, the filter limit can be set between $1.1F_{max}$ and F_{NY} [see subpara. 7.1.5(c)].

Prior to use, the tape recorder shall be checked for operability and calibrated. All pertinent information (signal recorded, data track designations, signal conditioner gain, tape speed, tape count, etc.) shall be completely and accurately entered in a comprehensive tape log; the tape log or a copy shall be stored inside the data tape container. If multiple data sets are recorded on a single tape, the tape should be advanced to leave a short unrecorded segment between data sets. A reference signal shall be recorded on each tape.

Signal gain changes should be avoided during recording sets. It is suggested that data recording be interrupted if a signal gain is changed. It is also suggested that a voice log be included on the tapes. The data being recorded shall be monitored on-line to add assurance of data quality and to meet precautions of section 10.

The following guidelines are for determining the record time length:

(a) Determine the parameters for which the data are to be reduced. Examples are rms accelerations, velocities, displacements, strains, power spectral densities, cross-spectral densities, coherences, and peak values.

(b) Determine what channels of data are to be cross-correlated in the subsequent data analysis or in the follow-up diagnosis. The channels to be cross-correlated must either be multiplexed or simultaneously recorded on the same multichannel magnetic tape or otherwise time phased.

(c) Determine the frequency range of interest.

(d) Determine the frequency resolution in the subsequent data analysis. From the reference in section 3, this can be estimated by

$$B_e \leq 2/\pi \ \xi_n f_n[(1 + p)^2 - 1]^{1/2} \tag{1}$$

where

B_e = frequency resolution
f_n = estimated modal frequency
p = acceptable fractional deviation from the true value (e.g., $p = 0.2$)
ξ_n = estimated damping ratio

As a rough guide, the bias error [see subpara. 3(b)] is acceptable if $p < 0.2$ so $p = 0.2$ is a good value for a first estimate of the frequency resolution.

Typical damping ratios in steam generator tube vary between 0.005 and 0.03. Therefore, $\xi = 0.005$ is a good conservative choice to estimate B_e. However, if in doubt, the resolution B_e should be varied to see if there is any significant change in the measured amplitude.

(e) Determine the record time length, T, required [see subpara. 3(b)] as follows:

$$T = \frac{1}{\epsilon^2 B_e} \tag{2}$$

where ϵ is the acceptable normalized error. In general, ϵ should be between 0.25 and 0.1. Equation (2) is true only if the bias error is acceptable [see subpara. 3(b)].

7.1.5 Data Reduction. Modern data reduction is almost universally done with specialized Fourier analyzers in which the analyst chooses some of the parameters while the Fourier analyzers' internal software sets the others. The procedure for data reduction depends on the particular Fourier analyzer used, but the following rules generally apply:

(a) Based on eq. (1), choose a suitable frequency resolution B_e.

(b) Choose a suitable block size N [see subpara. 3(b)]. In most Fourier analyzers, N is restricted to powers of 2 with an upper limit. Possible choices of N are 512, 1,024, 2,048, etc.

(c) The frequency resolution B_e and the block size together determine the *theoretical* maximum frequency, or the Nyquist frequency $F_{NY} = 0.5\ NB_e$. The actual maximum frequency of interest, F_{max}, should be always below the Nyquist frequency. How much below depends on the antialiasing filter used [see subpara. 7.1.5(d)]. For a 48 dB/octave filter, e.g., F_{max} should be below F_{NY}. If this is not satisfied, either B_e or N should be adjusted. If a steeper filter is used, F_{max} can be closer to F_{NY}.

(d) Set the antialiasing filter slightly above F_{max} but below F_{NY}. For an analyzer with a 48 dB/octave filter, the cut-off point can be set between $1.1F_{max}$ and F_{NY}. In some Fourier analyzers, the cut-off point is automatically set once F_{max} or F_{NY} is specified.

(e) Choose the number of averages n desired according to

$$n = \frac{1}{\epsilon^2}$$

where ϵ is the normalized error [see subpara. 3(b)]. Normally n should be between 16 and 100.

(f) The record time length per average is $1/B_e$. The total time length of record required is therefore n/B_e. This should be smaller than the total record time length recorded on tape.

7.1.6 Acceptance Guidelines and Follow-Up Actions. Data that is acquired and reduced following the guidelines provided in paras. 7.1.4 and 7.1.5 will permit the determination of vibration parameters that are generally needed to determine tube vibration characteristics and to support estimation of whether or not the vibration levels are acceptable. The parameters usually include the following:

(a) true rms or peak values of tube displacement and vibration velocity as a function of flow rate

(b) the occurrence, relative severity, and frequency of impacting

Information to support the interpretation of the data is provided in Nonmandatory Appendix E of this Part.

Acceptance criteria shall be established by the Owner, generally with the support of the manufacturer or other experienced sources for the specific heat exchanger under assessment. Guidelines to assist the Owner in identification of vibration levels that require further action are provided in Nonmandatory Appendix F of this Part. In some cases, specific information may be available regarding acceptable vibration levels for the heat exchanger being assessed. One example of such information would be the availability of both wear data and vibration data for numerous tubes. These data may enable the establishment of a relationship between measured tube vibration levels and resulting tube wear for the heat exchanger under evaluation. When available, such information shall take precedence over the guidelines in Nonmandatory Appendix F of this Part.

7.2 Microphone Scan for Tube Impacting

7.2.1 Introduction. The microphone scan method for impacting provides a method that can quickly and positively determine which particular tubes are vibrating severely enough to be impacting, a basis for deciding if more direct measurements (using the method outlined in para. 7.1) or remedial action are required. In some cases, this method also provides an approximate indication of the relative severity of impact of various tubes. It cannot provide detailed quantitative data such as can be acquired by direct measurement with in-tube probes.

Since the tube sheet must be accessible, the tubes are not subjected to the effects of tube-side fluid mass and temperature. Therefore, effects related to the absence of tube-side fluid should be considered when interpreting results from the application of this method.

7.2.2 Specification of Microphones and Signal Conditioners

(a) Basic System. A basic system consists of a microphone, audio amplifier, and headset. The recommended microphone is a ½ in. (12.7 mm) diameter size of the electret type (i.e., condenser microphone with built-in preamplifier). The amplifier should be a small battery-operated type, with plug-in jacks for microphone input and headset output and variable volume control. The earphones of the headset should be of a type that excludes extraneous sounds coming in from the room.

A recommended enhancement is to replace the amplifier with a small battery-powered tape recorder. This will provide the amplifier and volume control function and the capability to record microphone signals for the record and future reference.

(b) Filtering. The microphone signal will in general consist of two components arising from the impact. One is the low frequency mode of the air column in the tube. The other is high-frequency structure-borne sound. Either component may be selected by filtering: low-pass filtering for the low-frequency airborne sound and band-pass filtering (typically 2 kHz to 7 kHz) for the structure-borne sound.

For general use, switchable analog filter boxes employing Butterworth filters with sharp roll-off characteristics are recommended. For a specific application, fixed filters for the bandwidth of interest may be built.

(c) Chart Recording. For a quantitative permanent record, the microphone signals representing impact can be recorded on a strip chart recorder.

The frequency response of strip chart recorders is typically limited to below 50 Hz to 100 Hz. Microphone signals representing impact will normally contain higher frequencies. Therefore, the signals should be passed through full-wave rectification and peakhold detection circuits prior to recording. This process will convert a high-frequency burst of multiple tube impacts to a single event on the chart.

(d) Frequency Analysis. Frequency spectrum analysis will be useful in some cases. For example, it can identify the low-frequency and high-frequency content in the signals to assist with filter setting. Frequency analysis can also assist in relating observed impact rates to known or predicted tube vibration frequencies.

Frequency analysis can be performed on any FFT analyzer (or personal computer, with appropriate software).

Most analyzers and software also have the capability to capture time-waveform signals. This feature can assist with analysis and interpretation of data. For example, the time-waveform will show the individual impacts of a multiple impact burst, whereas the chart recording method will lump them into a single event.

7.2.3 Data Acquisition. Application of the method requires the following:

(a) access to the tube sheet(s)

(b) an air environment on the tube side

(c) shell-side flow

The microphone must be either inserted into or placed over an open tube end. Since the sound of metal-to-metal contact is transmitted to the microphone via the air column in the tube, it is important that the air column be sealed from the external environment at the opposite tube end using a suitable rubber plug or boot.

7.2.3.1 In application, the shell-side flow rate is varied (typically increased in steps) and the tube sheet (tube ends) is scanned with the microphone. Data acquisition methods include the following:

(a) audio monitoring using a headset (the quickest and simplest method)

(b) recording the time signals on tape (quantitative data are obtained for subsequent data reduction and analysis)

Audio monitoring is typically conducted first. Results from the audio survey are used to identify tubes from which more detailed, quantitative data are required.

7.2.4 Data Reduction and Interpretation. By carefully listening to sounds from the various tubes (audio monitoring with headset), it is possible to do the following:

(a) differentiate between an impacting and nonimpacting tube

(b) identify the tube groupings, or zones, that are experiencing impacting

(c) determine the threshold flow rate for impacting

7.2.4.1 Time histories are processed using techniques that involve the following:

(a) frequency spectral analysis

(b) filtering

(c) amplitude metering

(d) chart recording

7.2.4.2 Impacting is identified, in general, as a sudden burst followed by an exponential decay of the signal amplitude.

(a) Spectrum analysis provides the frequency content of the impact bursts. (Normally this will fall in the range of 0 kHz to 10 kHz, but extending the range to 20 kHz may be useful in some cases.)

(b) A quantitative indication of intensity is obtained by rms, or "peak" metering of the time signal. (Normally the impact burst is the dominant part of the total signal and the raw signal can be metered. Where extraneous components are present, filtering should be used to select only the impacting components for metering.)

(c) Limited experience indicates that amplitude of the microphone signal can be correlated with impact acceleration or directly measured with an in-tube probe. (This relationship has not been fully developed and generalized and, therefore, should be used as a guide and confirmed in any specific case.)

Case histories illustrating the use of tube sheet microphones are included in Nonmandatory Appendix E of this Part.

7.2.5 Impact Detection Guidelines and Remedial Actions. In all but exceptional cases, severe tube vibration can be detected by microphone scanning of the tube ends. Impact detection guidelines, with regard to the character of the noise as a function of flow rate and vibration severity, are the same as those given in para. 7.3.6 for external monitoring for impacting. The main result of the microphone scanning is the identification of specific tubes for direct vibration measurement (see para. 7.1) or remedial modifications (see para. 7.3.6).

7.3 External Monitoring for Impacting

7.3.1 Introduction. Very often the internals of an operational heat exchanger are not accessible without disassembly. Under this circumstance, external monitoring is the only way to check for severe tube vibration. To pinpoint the location and severity of the impacting, external monitoring can range from simply listening with the unaided ear to an externally shell-mounted accelerometer with an amplifier and a headset to multiple shell-mounted accelerometers with arrays of amplifiers and recorders for offsite correlation and wave analysis. Fundamentals of acquiring and reducing random vibration data are discussed in paras. 7.1.4 and 7.1.5.

7.3.2 Transducer Locations. Impacting has been successfully detected by transducers mounted on the heat exchanger shell adjacent to baffle edges, at locations of the tube sheet where there is direct mechanical contact to the shell, or at locations where local flow velocity is high and shell-to-tube (or tie-rod) clearance is minimum. Further information that will assist in sensor location may be obtained from the naked ear, from a handheld accelerometer survey, or from design information that indicates the tube(s) and span(s) most susceptible to flow-induced vibration.

7.3.3 Accelerometer Selection. Accelerometers are considered to be the best transducer for detecting metal-to-metal impacts. The following factors shall be considered in choosing an accelerometer for external monitoring of impacting:

(a) sensitivity

(b) frequency range

Accelerometer sensitivity must be high; often the energy release during impacting is very small. The frequency range should be sensitive to at least 10 kHz to measure higher mode response frequencies.

7.3.4 Accelerometer Mounting. Accelerometer mounting is very important to the quality of signal recorded. For detecting metal-to-metal impacts, neither magnetic nor strap mounting is recommended as these mountings are not rigid enough to ensure quality high-frequency signals. While the thread-mounted method is the best, it may not be necessary for qualitative detection of impacting. For this purpose, the best compromise between efficiency and quality is either cement mounting or epoxy mounting.

7.3.5 Accelerometer Cables and Signal Conditioning. The following shall be considered regarding accelerometer cables and in the selection of signal conditioning instrumentation:

(a) Low-noise (treated) cables designed specifically for accelerometer applications shall be used.

(b) The cable length recommended by the signal conditioner manufacturer shall not be exceeded.

(c) Remote charge converters or preamplifiers shall be used for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 100 ft (30 m) and should be considered when cable runs exceed 25 ft (7.6 m).

(d) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote

monitoring location or test enclosures may be necessary).

(e) The signal conditioner shall have multiple gain ranges to prevent signal over or under range.

(f) The signals should be filtered to minimize the effects of sensor resonance.

7.3.6 Impact Detection Guidelines and Remedial Actions. Minor vibrations that have characteristic sounds of light impacting often involve only one or two tubes and are intermittent rather than sustained. Severe vibrations, such as those from flow-excited instability, will be loud, sustained, and usually involve numerous tubes, producing a general clatter.

In some cases, initial identification of impacting may be more readily accomplished at flow rates that produce bursts of impacting than at flow rates that result in sustained impacting.

Follow-up actions when impacting is detected include one or more of the following:

(a) If a clear threshold is detected, limit operation to a flow rate that is below the threshold.

(b) Modify the equipment to eliminate expected causes of excessive vibration based on available structural and design information or data from additional testing.

(c) Identify impacting tubes by a microphone scan of the tube sheet (see para. 7.2). Remove these tubes from service by plugging and stabilization.

(d) Obtain direct tube vibration data to permit more specific evaluation of the impacts (see para. 7.1).

8 TEST CONDITIONS

Various test conditions may have to be considered and depend on the specifics of each case. Results of a test may dictate conditions for follow-up tests.

8.1 Shell-Side Flow Rate

The test should generally cover a range of flow rates. This test procedure will allow identification of tube vibrations that only occur over a particular range of shell-side flow rate. Additionally, operational requirements of the heat exchanger may specify its operation at reduced flow for extended periods before full flow is reached, and this condition shall be tested for excessive tube vibration.

Data shall be taken for the following conditions:

(a) shell-side flow rate incrementally increased 5% to 10% with associated steady states reached between 25% and 100% of maximum shell-side flow rate. Flow sweeps may be used to identify flow rates at which significant changes in signal levels occur. Smaller increments of flow change around these apparent flow rates shall be performed to adequately determine the flow rates at which changes in signal level occur and associated vibrational signal magnitude.

(b) shell-side flow rate at 100% flow and any flow rate condition associated with planned extended heat exchanger operation. These conditions are considered the most important steady-state operating conditions that affect tube integrity.

(c) shell-side flow rate of at least 110% of design flow unless prohibited by the manufacturer or precluded by operating constraints. This overflow condition will provide some insurance and documentation of margin against any severe tube vibration instability.

(d) the maximum flow rate if greater than the operating steady-state value at full power.

Caution is noted on maintaining a given flow rate at a condition that indicates significant tube vibration. In some cases, fluidelastically induced tube excitation can compromise tube integrity within a short period of time.

8.2 Rough Process Conditions

Shell-side flow rate is the primary variable in tube vibration. However, other process circuit parameters, such as fluid temperature, back pressure, flow imbalance or unsteadiness, off-design rough operation and valve settings, can be important. An effort shall be made to ensure that such conditions are covered by the test matrix.

9 DOCUMENTATION

The flow conditions and all significant process parameters for the test shall be documented. Direct measurements of shell-side flow and/or pressure drop across the shell are preferred. Where these are not available, the use of pump head characteristics and valve positions should be validated and carefully documented. Flow rates may be calculated using some of these characteristics.

The evaluation of tube vibration levels in accordance with subpara. 10(c) shall be documented.

10 PRECAUTIONS

The following precautions shall be observed during the planning and execution of heat exchanger vibration measurement programs:

(a) Adequate precautions shall be taken to ensure the safety of personnel associated with the test or near the equipment during all phases of the program.

(b) Instrumentation and other test hardware installation and removal shall be in accordance with all applicable codes and standards for the equipment being tested.

(c) Tube vibration levels shall be reviewed at each flow rate plateau. Acceptability should be determined before proceeding to higher flow rates.

Part 11, Nonmandatory Appendix A
Causes of Vibration

A-1 DISCUSSION

In general, tubes in a heat exchanger will vibrate at all flow rates. However, it is the large-amplitude motion associated with fluidelastic instability that is usually of most concern. This large motion has the potential to lead to early failure of the equipment. The small-amplitude motion associated with subcritical flow rates is generally acceptable. However, there are situations in which vortex shedding or high turbulence levels in combination with adverse or inadequate support conditions or support deterioration can cause unacceptable tube vibration.

Acoustic noise has also been a problem encountered in heat exchangers. For the most part, the problems that have been reported are for larger exchangers with a gas or two-phase fluid flowing on the shell side. The resulting intense sound level generated in the area of the heat exchanger is usually intolerable and the potential for acoustic excitation of the heat exchanger walls must be considered. Tube bundle vibration is generally not a concern except where there is a triple coincidence among the fluid excitation, acoustic vibration, and tube vibration frequencies.

Significant progress has been made in understanding the fluid excitation mechanisms and in the development of related design guidelines. For the most part, the studies and design methodology are based on idealized laboratory tests involving single-span tube arrays subjected to uniform cross-flow. However, application to an actual heat exchanger is not at all straightforward because of the complex flow distribution in shell and tube exchangers and the complexities associated with the tube support arrangement, such as tube support plate clearances. Inlet/outlet nozzle sizes, impingement plates, inlet/outlet flow distributors, baffle size and spacing, and leakage paths, both between shell and tube bundle and between tubes and baffle plate holes, will all affect the flow velocity distribution. Tube vibrational characteristics (e.g., natural frequencies, mode shapes, damping, and degree of nonlinearity in response) will be determined by baffle spacing, tube-to-baffle-hole clearance, baffle plate alignment, tube straightness, mechanical fit-up of the tubes and tube axial loads both initially and under operating conditions, tube layout (i.e., pattern and pitch), and the properties of the shell-side fluid.

In addition to excitation by shell-side flow, there is the possibility for structural-borne excitation to contribute to the vibration of tube bundles. Excitation sources would include floor vibration, as might be caused by rotating machinery. Transmission paths would include heat exchanger support structures and connecting piping. In general, it is difficult to predict such vibration sources and related energy transmission a priori, as they will be site specific.

The dynamic behavior of a typical industrial size heat exchanger tube bundle is reported in the references in subparas. A-2(a) through A-2(f). In general, the tube vibration behavior as the shell-side flow rate is increased can be summarized as follows: at low flow rates, small-amplitude tube motions occur, typically random in nature; these increase to cause rattling within the baffle (support) plate hole as the flow rate is increased; large-amplitude motion and typically tube-to-tube and/or tube-to-baffle plate impacting results when the flow rate becomes sufficiently high. This behavior is shown in Fig. A-1, where one can see the small-amplitude response at low flow rates and can identify a threshold flow rate [in this case, ~1,950 gal/min (442.8 m^3/h)] above which large-amplitude tube vibration and tube impacting occurs.

Figure A-2 shows typical power spectral density (PSD) representations of the acceleration response of a tube for a range of flow rates. For this example, the threshold or critical flow rate occurs in the range 2,200 gal/min to 2,400 gal/min (499.6 m^3/h to 545.0 m^3/h). It is interesting to note that at subcritical (below the threshold flow rate for large-amplitude vibration) flow rates, the tube response includes contributions from a band of frequencies, while above the critical flow rate the tube response is at a single frequency involving a particular mode.

The three mechanisms generally regarded as responsible for the vibration of heat exchanger tubes are turbulent buffeting, vortex shedding, and fluidelastic instability.

Turbulent buffeting is present at all flow rates and includes random pressure fluctuations associated with the turbulent boundary layer, as well as turbulent wake flows from upstream tubes or other flow path obstructions or irregularities such as the inlet. In general, it is random in nature and can be generally considered responsible for the low level tube vibration and rattling experienced at subcritical flow rates. See Figs. A-1 and A-2 for examples of response behavior. In some cases, inlet turbulence can generate significant tube motion. Analysis methods for buffeting response are based on

Fig. A-1 Root Mean Square (rms) Acceleration Versus Flow Rate From Three Typical Tubes

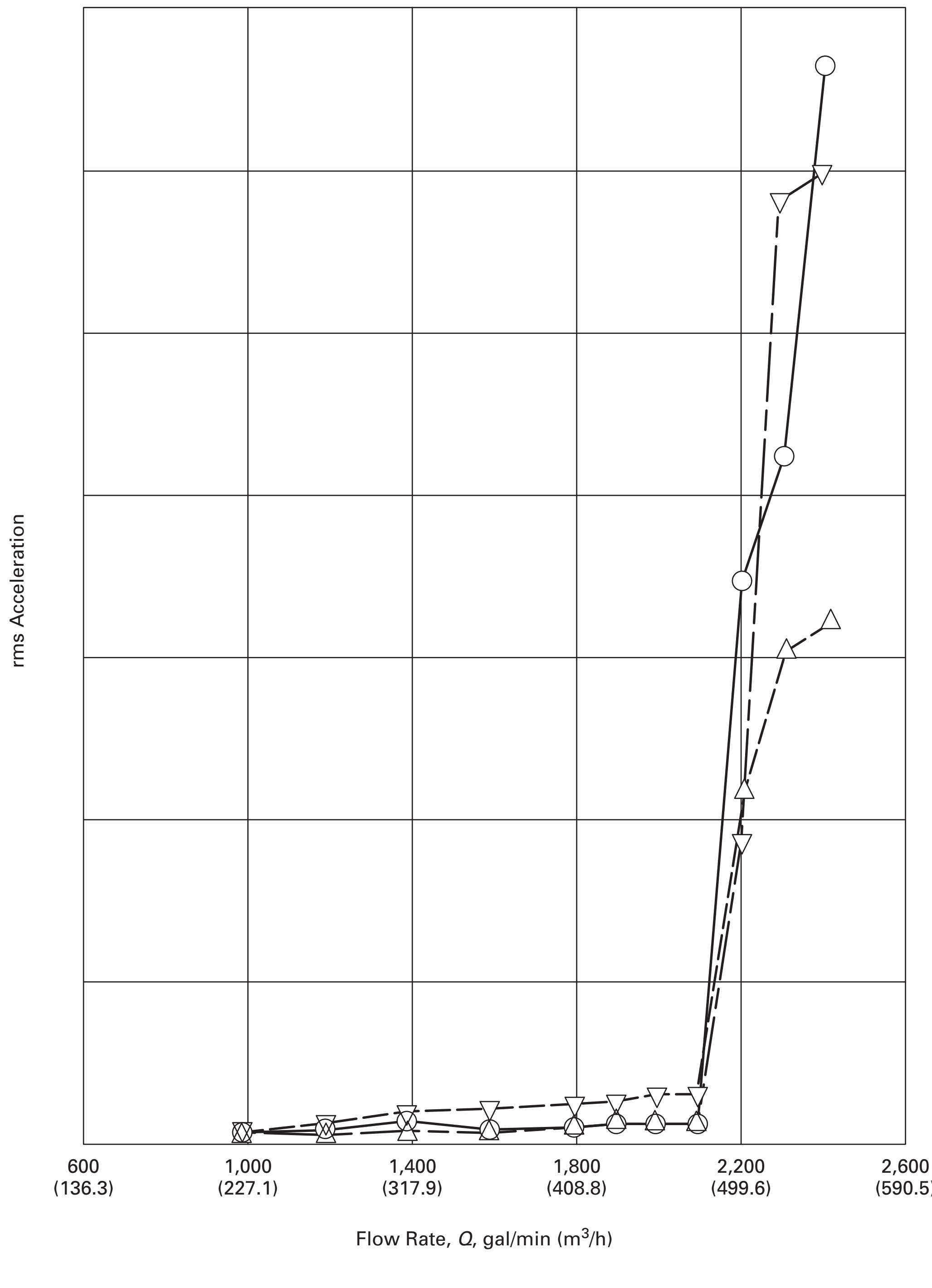
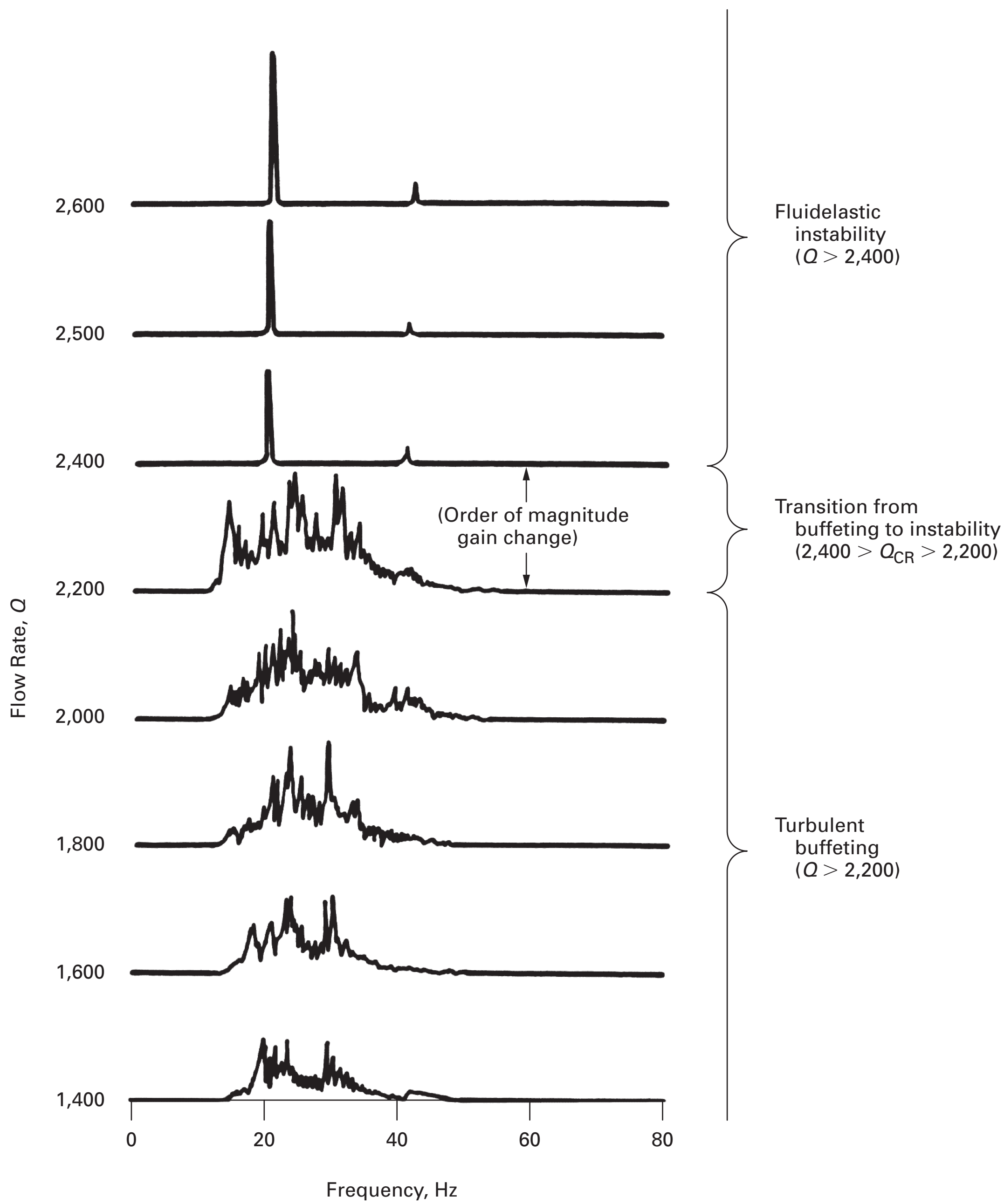


Fig. A-2 Tube Response PSDs for Various Shell-Side Flow Rates (Ordinate Not to Scale)



random vibration theory or measured excitation forces [see subpara. A-2(g)].

Vortex shedding, while an important mechanism for single cylinders exposed to cross-flow, is generally not important for a tube bundle unless the tube spacing is large (pitch-to-diameter ratio, $P/d > 2.0$). For most industrial heat exchangers the spacing is relatively small with typical values of P/d ranging from 1.25 to 1.40.

The mechanism generally of most concern is fluidelastic instability, as it leads to large-amplitude motion that persists once the threshold flow rate is exceeded. Fluidelastic instability, of the type responsible for tube bundle vibration, has been the subject of a considerable number of investigations, both experimental and theoretical [see, for example, subparas. A-2(h) and A-2(i)].

While significant progress is being made in developing an understanding of fluidelastic instability phenomena in tube bundles, the state-of-the-art has not yet progressed to the point that would allow calculation of the fluid dynamic force coefficients required for an analytical prediction of the threshold flow velocity for a particular tube bundle. Consequently, in design, it is still necessary to rely on experimental data obtained from laboratory tests. In a design guide, available experimental data have been assembled and stability diagrams plotted in the form of dimensionless parameters [see subpara. A-2(j)]. However, application of the stability diagrams, as well as the equation forms of the stability criteria, to the design evaluation of an actual heat exchanger is not straightforward. In particular, application is complicated by the complexities of the flow distribution within the heat exchanger, not to mention inherent uncertainties and nonlinearities related to the degree of tube support provided by the baffles that will directly affect tube vibrational characteristics.

A-2 REFERENCES

The following is a list of publications referenced in this Nonmandatory Appendix:

(a) H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger," ANL Technical Memorandum ANL-CT-80-18 (March 1980)

(b) H. Halle, J. M. Chenoweth, and M. W. Wambsganss, "Flow-Induced Tube Vibration Tests of Typical Industrial Heat Exchanger Configurations," ASME 81-DET-37, 8th ASME Vibrations Conference (Hartford, CT, September 1981)

(c) M. W. Wambsganss, H. Halle, and W. P. Lawrence, "Tube Vibration in Industrial Size Test Heat Exchanger (30° Triangular Layout—6 Crosspass Configuration)," ANL Technical Memorandum ANL-CT-81-42 (October 1981)

(d) H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger (90° Square Layout)," ANL Report ANL-83-10 (February 1983)

(e) H. Halle, J. M. Chenoweth, and M. W. Wambsganss; M. P. Paidoussis, J. M. Chenoweth, and M. D. Bernstein, eds.; "Flow-Induced Tube Vibration Thresholds in Heat Exchangers from Shellside Water Tests," ASME Symposium on Flow-Induced Vibration; Vol. 3, Vibration in Heat Exchangers (New York, NY, 1984): 17–32

(f) H. Halle, J. M. Chenoweth, and M. W. Wambsganss, "Tube Vibration in Industrial Size Heat Exchanger (22 Additional Configurations)," ANL Report ANL-85-66 (December 1985)

(g) T. M. Frick, "Summary of Preheat Steam Generator Experiences and the Basis for a Turbulent Force Modeling Procedure," Transactions of the 8th International Conference on Structural Mechanics in Reactor Technology, Vol. D, Paper D3/2 (1985): 283–287

(h) M. P. Paidoussis, "Flow-Induced Instabilities of Cylindrical Structures," ASME Applied Mechanics Review, Vol. 40 (2) (1987): 163–175

(i) S. S. Chen, "Flow-Induced Vibration of Circular Cylindrical Structures," Hemisphere Publishing Corp. (Washington, 1987)

(j) S. S. Chen, "Guidelines for the Instability Flow Velocity of Tube Arrays in Crossflow," ASME Journal of Sound and Vibration, Vol. 93 (1984): 439–455

Part 11, Nonmandatory Appendix B
Methods for Comparative Evaluation of Fluidelastic and Turbulence-Induced Vibration

B-1 INTRODUCTION

This Nonmandatory Appendix gives simplified methods to assess the need for detailed testing. Very often a particular design of proven field performance is modified to suit a specific need or as a result of field repair or operation. However, if the modification is sufficiently minor that the integrity of the "new" design can be established by comparative analyses with a heat exchanger of proven field performance as the reference, detailed tests may not be necessary. Because the following methods are highly simplified, they are conservative. Failure to meet the criteria, therefore, does not necessarily mean that the design is inadequate. It simply means that either testing or a more exact method of analysis, probably with vendor-specific data as input, is necessary.

(15) B-2 NOMENCLATURE

B = fluidelastic stability constant, dimensionless
C = mode shape weighting factor, dimensionless
C_r = random lift coefficient, $\sec^{-1/2}$
D = tube outside diameter, in. (m)
E = Young's modulus, psi ($N \cdot m^2$)
f_j = tube modal frequency, Hz
I = moment of inertia, in.^{4} (m^4)
i = span index
j = modal index
L = characteristic length, in. (m)
l = tube overall length, in. (m)
l_i = length of span i of the tube, in. (m)
m = total mass (structural, fluid, and virtual) per unit tube length, lb sec^2/in.^{4} (kg/m)
m_o = reference (usually an averaged value) total mass per unit length, lb sec^2/in.^{4} (kg/m)
M_j = modal generalized (total) mass, unit depends on mode shape normalization
Q = shell-side volumetric flow rate, in.^{3}/sec (m^3/s)
U_e = equivalent mode shape weighted cross-flow velocity, in./sec (m/s)
U_m = mean cross-flow gap velocity, in./sec (m/s)
$U(x)$ = cross-flow gap velocity, in./sec (m/s)
y = tube vibration amplitude, in. (m)
$Y(x)$ = cross-flow velocity distribution function, dimensionless
ξ_j = modal equivalent viscous damping ratio, dimensionless
ϕ_j = tube vibration mode shape, unit depends on normalization convention
ρ = fluid mass density, lb sec^2/in.^{4} (kg/m^3)
ρ_o = reference (usually an averaged value) fluid mass density, lb sec^2/in.^{4} (kg/m^3)

B-3 FLUIDELASTIC INSTABILITY (15)

A parameter grouping can be defined and used as "figure of merit" to assess the design acceptability from the standpoint of fluidelastic instability and for the determination of the need for testing or redesign. The parameter grouping applies to designs that have single-phase flow on the shell side and are geometrically similar to a reference design that has been determined acceptable via testing or successful operation, or both, but are subject to differences in service conditions (e.g., flow rate and temperature), shell-side fluid flow, or tube material.

A fluidelastic stability margin can be defined as

$$R_j = U_c/U_{ej} \tag{B-1}$$

where U_c is the critical velocity for fluidelastic instability given by

$$U_c = Bf_jD(2\pi\xi_j m_o/\rho_0 D^2)^{1/2} \tag{B-2}$$

and U_{ej} is an equivalent mode weighted cross-flow velocity for mode j defined as

$$U_{ej} = \left\{\frac{(1/\rho_o)\int_o^l \rho(x)U^2(x)\phi_j^2(x)\,dx}{(1/m_o)\int_o^l m(x)\phi_j^2(x)\,dx}\right\}^{1/2} \tag{B-3}$$

Equations (B-1) through (B-3) together indicate that a given heat exchanger tube bundle will experience fluidelastic instability if $R_j < 1.0$

Furthermore, the larger the R_j above unity, the larger the fluidelastic stability margin. Equation (B-1) can be interpreted as the stability criterion. Note that in eq. (B-1) the reference mass densities m_o and ρ_0 cancel out. In eq. (B-3), $U(x)$ can be represented as

$$U(x) = U_mY(x) \tag{B-4}$$

Substituting eq. (B-4) into eq. (B-3) yields

$$U_{ei} = C_j U_m \tag{B-5}$$

where C_j is a mode weighting factor defined as

$$C_j = \left\{ \frac{(1/\rho_o) \int_o^l \rho(x) Y^2(x) \phi_j^2(x)\, dx}{(1/m_o) \int_o^l m(x) \phi_j^2(x)\, dx} \right\}^{1/2} \tag{B-6}$$

For geometrically similar heat exchangers, in which the fluid density and total tube mass is also uniform along the length of the tube, C_j can be assumed to be the same and the following proportionalities can be used:

$$f_j^2 \alpha EI/L^4 m \tag{B-7}$$

$$U_m \alpha Q/L^2 \tag{B-8}$$

Equations (B-1), (B-2), and (B-5) through (B-8) together give

$$R_j \alpha K = (EI\zeta/\rho Q^2)^{1/2} \tag{B-9}$$

where it has further been assumed that $\xi_j = \xi_i$, i.e., for a given heat exchanger the equivalent viscous damping ratio is the same for all modes.

The parameter grouping K, defined by eq. (B-9), can be used to assess a geometrically similar design by carrying out the following procedure:

(a) Calculate K for the reference design and designate it K'.

(b) Calculate K for the design under consideration.

(c) Calculate the ratio $S = K/K'$.

(d) If $S > 1.0$, testing is not required.

(e) If $S < 1.0$ and the reference design has been tested and known to have been operating close to the critical flow, the design is unacceptable.

(f) If $S < 1.0$ and the reference design is operating below the critical flow, testing is required.

B-4 SIMPLIFIED METHOD FOR ESTIMATING TURBULENCE-INDUCED VIBRATION IN A SIMILAR DESIGN

For designs with single-phase flow on the shell side that are similar to a reference design that has been determined acceptable via testing or successful operation, or both, but are subject to differences in operating conditions (e.g., flow rate and temperature) and tube-to-support plate clearances (due to chemical deposit or cleaning) with resulting differences in flow velocities, fluid densities, tube axial load (and thus tube natural frequencies), and damping ratios, the following simplified equation can be used to estimate the ratio of the turbulence-induced vibration amplitude of the "new" design to that of the reference design:

$$\frac{y}{y_R} = \sum_j \frac{\rho Q^2 C_r(f_j)}{\rho_R Q_R^2 C_r(f_{Rj})} \left\{ \frac{M_{Rj}^2 f_{Rj}^3 \zeta_{Rj}^3}{M_j^2 f_j^3 \zeta_l} \right\}^{1/2} \tag{B-10}$$

where the summation is over all the important modes and subscript R denotes the reference design. $C_r(f)$ is the random turbulence excitation coefficient at frequency f. From Pettigrew's data [see subpara. B-5(a)], an upper bound estimate for the turbulence excitation coefficient can be derived (see Table B-1).

NOTE: As defined in eq. (B-10) and in subpara. B-5(a), C_r has dimensions of $\sec^{-1/2}$.

If $y < y_R$ by a margin large enough to accommodate the uncertainties in the parameters that determine the responses, then testing is not necessary.

For designs that are geometrically similar but not identical to a reference design, a more detailed analysis is necessary to alleviate testing [see subpara. B-5(b)]. Following the reference in subpara. B-5(c), the upper bound mean square response of a multispan tube bundle is given by

$$y^2(x) = \sum_j \sum_i \frac{l_i G_\rho^{(i)}(f_j) \phi_j^2(x)}{64\pi^3 M_j^2 f_j^3 \zeta_j} \tag{B-11}$$

where

$$G_\rho^{(i)}(f) = (D/2)^2 C_r^2(f) \int_o^{l_i} [\rho(x) U^2(x)]^2 \phi_j^2(x)\, dx \tag{B-12}$$

is the mode shaped, weighted, span-averaged turbulence pressure power spectral density and the summation is over all the spans i and all the important modes j contributing to the response. Extensive testing is not necessary if application of eqs. (B-11) and (B-12) to both the new and the reference designs shows that

(a) the amplitudes of response and the resulting stresses are well within the allowable limits for wear and fatigue for both the new and the reference designs.

(b) the computed vibration amplitude and stress for the new design are equal to or less than those of the reference design.

Equation (B-11) is a very conservative estimate of the turbulence-induced vibration amplitude of a multispan tube bundle and bounds the lock-in vortex-induced vibration amplitude. Failure to meet the above requirements, therefore, does not necessarily mean that the design is not acceptable, or even that detailed tests must be done. It just means that a more detailed analysis [see the reference in subpara. B-5(b)], possibly backed up by more refined vendor-input data, is necessary to alleviate detailed tests.

Table B-1 Upper Bound Estimate of the Random Turbulence Excitation Coefficient for Tube Bundle

Frequency, Hz	C_r, sec$^{-1/2}$
0–40	0.025
50	0.017
60	0.012
70	0.0083
80	0.0058
90	0.0040
100	0.0028
110	0.0019
120	0.0013
140	0.00092
160	0.00031
180	0.00015
200	0.000071

B-5 REFERENCES

The following is a list of publications referenced in this Nonmandatory Appendix:

(a) M. J. Pettigrew and D. J. Gorman, P. Y. Chen, ed., "Vibration of Heat Exchanger Tube Bundles in Liquid and Two-Phase Cross Flow," Flow-Induced Vibration Design Guidelines, ASME PVP-Vol. 52 (1981)

(b) M. K. Au-Yang and B. Brenneman, "Flow-Induced Vibration Analysis of an Integral Economizer Once-Through Steam Generator," ASME Journal of Pressure Vessel Technology, Vol. III (1989): 501–506

(c) M. K. Au-Yang, "Turbulent Buffeting of a Multi-Span Tube Bundle," ASME Journal of Vibration, Stress, Acoustics, and Reliability in Design, Vol. 108 (1986): 150–154

Part 11, Nonmandatory Appendix C
Test Guidelines for Dynamic Characterization of Tubes

C-1 TUBE MECHANICAL VIBRATION CHARACTERISTICS

Test guidelines are outlined below for the following:

(a) modal frequency determination

(b) mode shape characterization

(c) modal damping estimates

In using the results, consideration should be given to the effects of fluid if the test is performed in air and also to motion of the surrounding tubes.

C-2 MODAL FREQUENCIES AND DAMPING DETERMINATION

The following is the test procedure:

(a) Identify the location of each tube selected for testing. A minimum of three tubes is necessary to give reasonable statistical confidence.

(b) Install one or more biaxial accelerometers in each of the tubes selected. Usually some specially developed tools are necessary to install the accelerometers.

(c) Connect the accelerometer to the signal conditioners, tape recorders, and online spectrum analyzer.

(d) Set the appropriate frequency range of the spectrum analyzer and adjust the analyzer to capture a single transient. For most applications, an upper frequency limit of 500 Hz is suitable.

(e) Impulsively excite the tubes by hammer impacting the tubes directly or by impacting the exterior of the shell.

(f) Determine the tube modal frequencies from the spectrum peaks.

(g) Determine the modal damping ratio by the logarithmic decay method. If X_n and X_{n+1} are the amplitudes of two consecutive cycles, then

$$\xi = \frac{C}{C_C} = \frac{1}{2\pi} \log_e \frac{X_n}{X_{n+1}}$$

where C is the damping coefficient and C_C is the critical damping ratio. In practice, plotting of this function on semilog paper over several cycles is necessary to obtain reliable results.

(h) Repeat the above procedure for each of the tubes selected.

(i) Using statistical analysis technique, check for normality, mean, and standard deviation of the modal frequencies and damping ratios determined from the ensemble of tubes selected for testing.

C-3 MODE SHAPE CHARACTERIZATION

The following are the test procedures:

(a) Install a reference biaxial accelerometer, with its sensitive axes perpendicular to the tube, approximately $\frac{1}{8}$ span from the support plate.

(b) Install a movable biaxial accelerometer in the tube with its sensitive axes perpendicular to the tube.

(c) Connect both accelerometers to the signal conditioner, spectrum analyzer, and tape recorder.

(d) Excite the tubes as outlined in section C-2. Record the tube responses at the locations of both the reference and movable accelerometers.

(e) Move the movable accelerometer to another location and repeat the procedure.

(f) Determine the amplitude ratio and phase relative to the reference accelerometer at each of the movable accelerometer locations.

(g) Determine the mode shape of the tested tube span by curve fitting of the data points.

Part 11, Nonmandatory Appendix D
External Vibration Surveys

D-1 INTRODUCTION

The purposes of an external survey are as follows:

(a) to assess the likelihood of significant tube vibration due to motion of tube supports by vibration transmitted from supporting structures, piping, valves, or machinery.

(b) to assist in the determination of causes of tube vibration or wear detected by other means. A walk-around inspection should be made of the tube sheets, shell and supporting structure, and nearby connected piping to identify unusually large vibrations.

D-2 MEASUREMENT LOCATIONS

Vibration at the tube sheets and shell should be measured and recorded. If determined to be excessive, vibration at other locations on structure, piping, valves, and the like should be measured and recorded for diagnostic purposes.

D-3 ACCEPTANCE GUIDELINES AND RECOMMENDED FOLLOW-UP

Acceptance levels should be established by the Owner. If system-specific information is not available, reference can be made to various standards for machinery, piping, and structural vibration (see Nonmandatory Appendix F of this Part). If the survey indicates significant levels, the vibration data should be examined for frequency content near the natural frequencies of the tubes. If such content is present, the effects should be determined by analysis or additional measurements. Determination of tube natural frequencies should consider the potential for ineffective support at one or more tube supports.

Part 11, Nonmandatory Appendix E
Detection Methods and Data Interpretation

E-1 INTRODUCTION

The threshold flow velocity corresponding to the onset of instability is not always easy to determine in laboratory tests and is even more difficult to establish in the case of real heat exchange equipment. The situation involving a real heat exchanger is complicated by the large number of tubes in the bundle, several possible tube support arrangements, and the complex (nonuniform) flow distribution, all of which will result in specific groups of tubes experiencing instability at a different flow rate than other groups of tubes.

The methods and data described in this Nonmandatory Appendix are provided to assist the user in identifying tube impacting and in the recognition of impacting in signal time histories, and to provide guidance on the identification of threshold levels for large amplitude vibrations due to fluidelastic excitation. There are numerous methods available for detecting tube impacting and for defining the threshold flow rate for instability from tests and associated test data. These are reviewed below together with sample data plots.

E-2 AURAL OBSERVATIONS

In general, tube vibration amplitudes increase dramatically when the critical flow rate is reached, often causing the tubes to impact with one another or with the tube support plates. Typically, a distinctive, loud noise associated with the metal-to-metal impacting is readily audible. The method is applied by increasing the flow in steps, or continuously at a slow rate, and listening for an abrupt increase in sound level. When the tubes are vibrating at sufficiently large amplitudes to cause audible impacting, it should be regarded as evidence that excessive tube vibration is highly probable.

One disadvantage of this method is that it is somewhat subjective and requires some engineering judgment and experience. A second disadvantage is that the results may not be conservative, considering that the tubes may have gone unstable at moderate amplitudes without impacting, at a somewhat lower flow than that identified by listening. An obvious advantage is that the method is fast, easy to apply, and allows for surveillance of the entire bundle at one time.

E-3 ACCELEROMETER SIGNAL CHARACTERISTICS DURING METAL-TO-METAL IMPACTING

The use of shell-mounted or in-tube accelerometers and microphones mounted in tube ends to detect metal-to-metal impact is reported in the references in subparas. E-6(a) and E-6(b). The appearance of an accelerometer signal time history with tube impacting is shown in Fig. E-1. In some cases, impacting is buried in the wideband signal and may not be detectable without filtering [see subpara. E-6(k)]. In such cases, high-pass filtering improves the detection of impacting (see Fig. E-1). Further characterization of the impacting is possible with the use of an envelope detector [see subpara. E-6(b)]. Figure E-2 presents a comparison of concurrent time histories of an in-tube accelerometer and a tube-end microphone mounted in the same tube, demonstrating the one-to-one correspondence of events.

Impacting is also reflected in the acceleration signal frequency spectrum as a high-frequency narrowband peak (see Fig. E-2).

E-4 DETECTION OF VIBRATION CAUSED BY FLUIDELASTIC EXCITATION WITH TUBE-MOUNTED SENSORS

The methods described below each require instrumenting selected tubes with accelerometers or other motion-sensing devices. Again, the flow is increased in steps or swept at a slow rate starting from a low value. Typically, the response time histories are recorded on magnetic tape for subsequent data processing. With tube-mounted vibration sensors, indications of the possible onset of fluidelastic vibration are as follows:

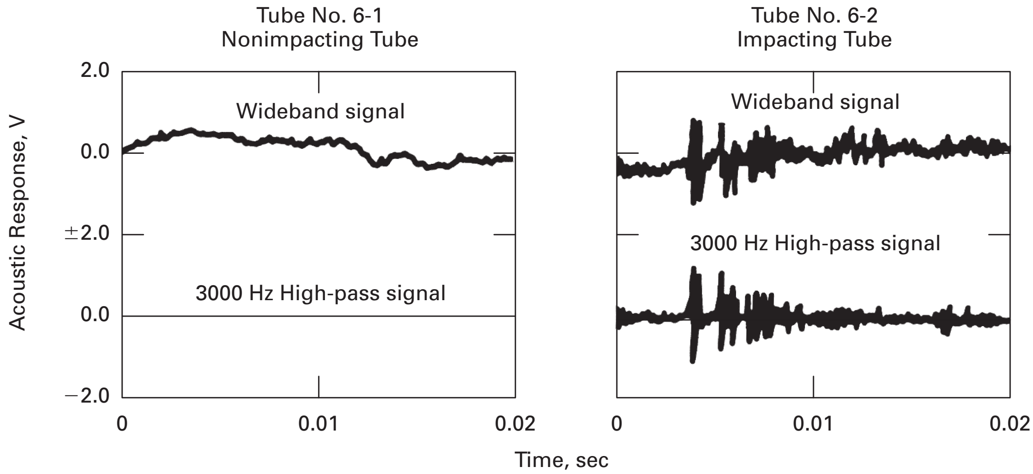
(a) high rate of increase in the tube vibration response versus increase in flow rate

(b) change in frequency response from multiple, closely spaced frequencies to a single, well-defined frequency

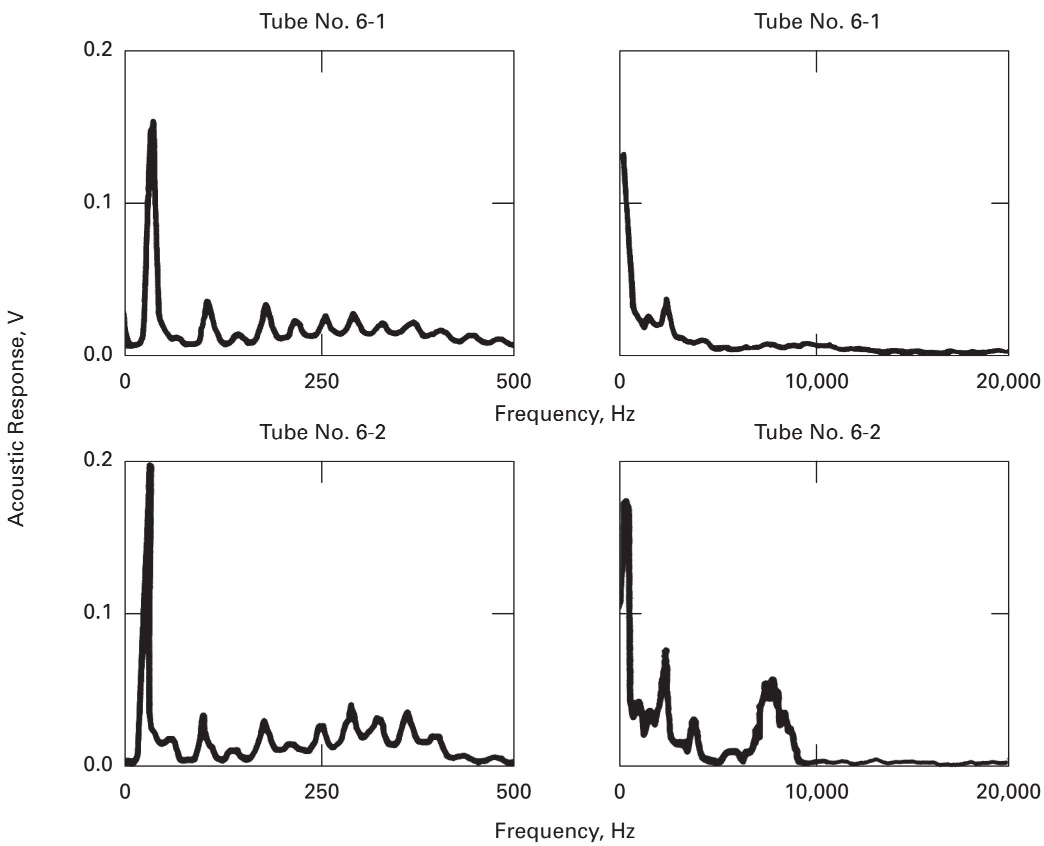
(c) change from a random to a well-defined tube trajectory

Several examples of heat exchanger tube amplitude plots and frequency spectra are presented as further background on the detection of vibration caused by fluidelastic excitation described in Nonmandatory Appendix A. These examples have been chosen to show the detection methods and to point out difficulties inherent in interpretation of the data.

Fig. E-1 Acoustic rms Spectrum for Nonimpacting Tube (No. 6-1) and Impacting Tube (No. 6-2)

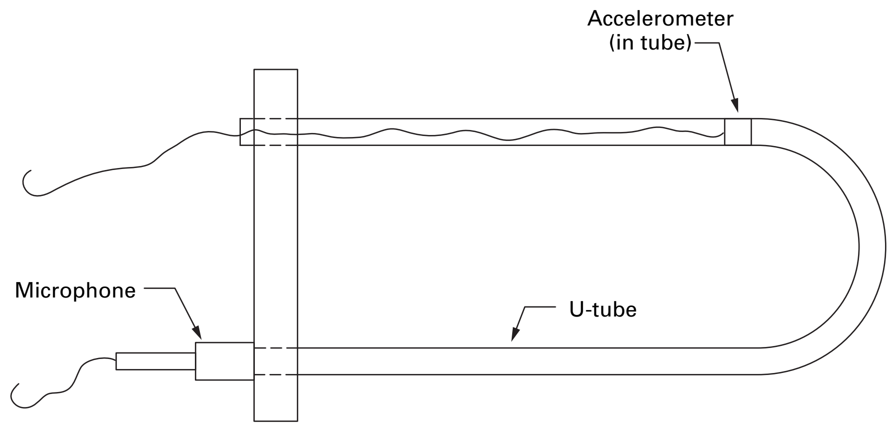


(a) Time History Plots for Impacting and Nonimpacting Tubes

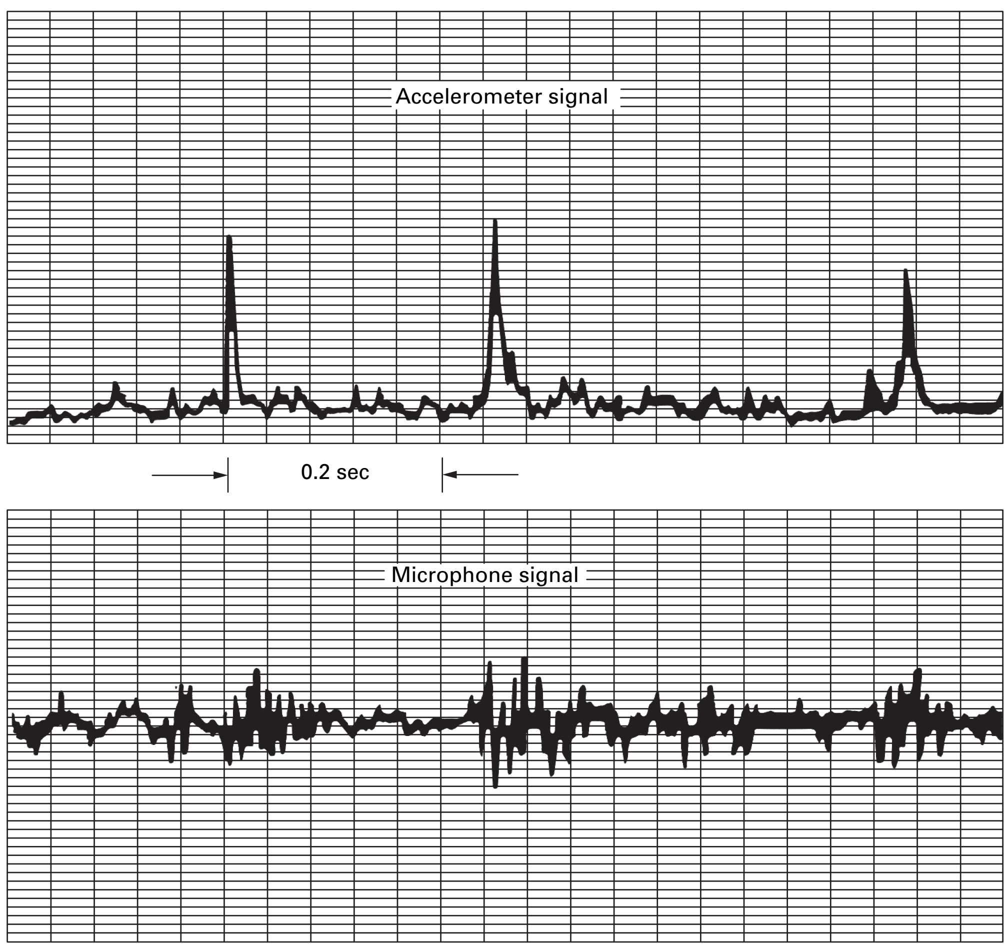


(b) Acoustic rms Spectrum for Nonimpacting Tube (No. 6-1) and Impacting Tube (No. 6-2)

Fig. E-2 Correlation of Signals From Microphone and In-Tube Accelerometer



(a) Locations of the Sensors



(b) One-to-One Correspondence of Events

E-4.1 Vibration Amplitude Versus Flow Response Rate

The tube vibration response time histories are processed to obtain rms values of acceleration or displacement. The rms response is plotted as a function of flow velocity or flow rate. Illustrations of the types of curves that can be obtained are shown in Fig. E-3. The flow velocity at which the tube experiences a rapid increase in response is defined as the critical flow velocity. The reference in subpara. E-6(c) defines the critical flow velocity as the intersection of the velocity axis and the tangent to that portion of the curve that is rapidly rising [see Fig. E-3, illustration (a)].

Figure E-3, illustration (a) is the ideal and there is no problem in defining the critical flow rate with this method. However, typically (with water on the shell side) the response versus flow curve may peak, drop off, and then show a rapid rise. See, for example, Fig. E-3, illustration (b). There is uncertainty in such cases as to whether or not the first peak indicates instability. Problems in definition also arise in cases in which the rms response exhibits a gradual increase to a high level, as in Fig. E-3, illustration (c), rather than an abrupt increase, as in Fig. E-3, illustration (a). This gradual trend has been observed to occur with two phase flow on the shell side of the heat exchanger.

Typical response versus flow curves are given in Figs. E-4 and E-5. The data given in Fig. E-4, illustration (a) are from laboratory tests of a 5 × 5 tube array exposed to cross-flow; the curves correspond to various tubes within the array [see subpara. E-6(a)]. Figure E-4, illustration (a) represents an example of a well-defined instability similar to that illustrated in Fig. E-3, illustration (a); the critical flow velocity can be readily established. The curves of Fig. E-4, illustration (b), on the other hand, are of the type illustrated in Fig. E-3, illustration (b) and are more difficult to interpret. It has been suggested that the peak in the response curve may be associated with response due to vortex shedding. Experience has shown that the instability is better defined for cases involving high damping.

The data given in Fig. E-5 are from four different tubes in a vibration test of an industrial size, segmentally baffled, shell-and-tube heat exchanger with water as the shell-side fluid; data were obtained both sweeping up and sweeping down in flow [see subpara. E-6(e)]. Examination of the curves of Fig. E-5 leads to the following observations, which serve to demonstrate the types of response one can expect from a vibration test:

(a) All four tubes exhibit a peak in the response curve with increasing flow rate; the peak is nonexistent for decreasing flow.

(b) Hysteresis is present for two cases [see Fig. E-5, illustrations (b) and (c)]; the flow rate at which the instability drops out is less than the threshold for the onset of instability.

(c) The instability flow rate is well defined in Fig. E-5, illustrations (b) and (c); the increase in response is very abrupt.

(d) It is more difficult to define a critical flow rate in Fig. E-5, illustration (a); the rate of increase of response with flow rate is relatively gradual.

E-4.2 Vibration Amplitude Versus Flow Amplitude Threshold

To overcome the ambiguity in establishing the critical flow velocity for cases in which the rms response versus flow curves exhibit "undulations," a gradual rise, or both, several investigators have established a "threshold displacement amplitude." The critical flow velocity is defined as the velocity at which the threshold displacement is first exceeded.

Once a threshold amplitude is established, the method is straightforward in application [see Fig. E-3, illustration (b)]. However, again, engineering judgment is required in the selection and application of the criterion. See, for example, subpara. E-6(f).

E-4.3 Time History

A slow sweep up in flow is performed while tube acceleration time histories are recorded on magnetic tape. A careful examination of the time histories is carried out to determine the time (corresponding to a particular flow) at which large amplitudes suddenly occur. Peak amplitudes can be compared with the available clearance to determine if impacting between tubes can be expected to be occurring (with measurements from adjacent tubes or on the assumption of similar amplitudes of adjacent tubes).

In application of this method, the relationship of the vibration mode relative to the axial location of the accelerometer in the tube must be considered. Depending on the mode shape, the peak response in one span can be significantly greater than that in an adjacent span. Therefore, if the accelerometer is located in a span with a smaller relative motion, analysis of the response peaks may indicate that impacting is not occurring whereas it may, in fact, be occurring in an adjacent span. This method can be rather tedious and time-consuming to apply. It, too, requires engineering judgment.

Sample time histories from a heat exchanger tube vibration test are shown in Figs. E-6 and E-7 [see subpara. 6(g)]. The flow rate is being slowly increased with time. The rather abrupt buildup of large-amplitude motion is the result of a fluidelastic instability. The time of occurrence can be correlated with a flow rate versus time history to determine the critical flow rate. Displacement time histories are also useful in assessing possible tube-to-tube impacting; peak amplitudes can be compared with tube spacings and available clearance. In addition, acceleration time histories should be reviewed for indications of impacting as discussed in section E-3.

Fig. E-3 Root Mean Square (rms) Tube Response Versus Flow Velocity

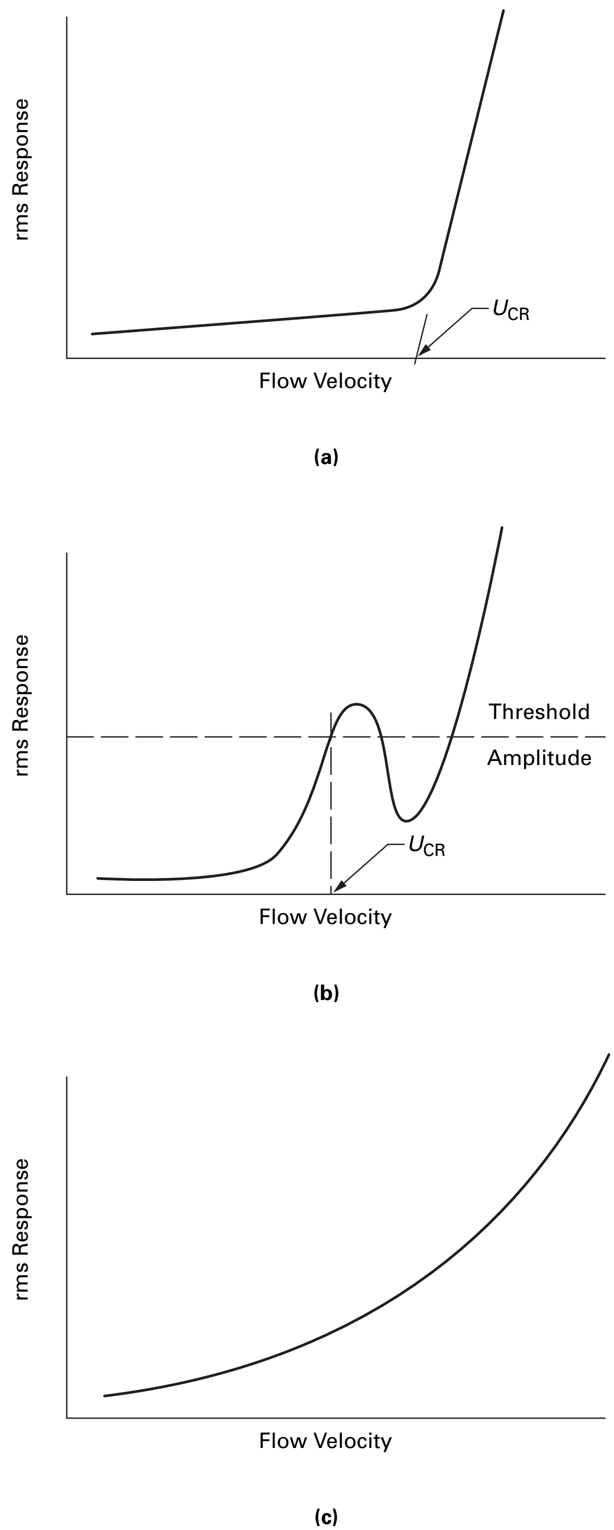


Fig. E-4 Response Versus Flow Velocity (Laboratory Test of 5 × 5 Tube Array)

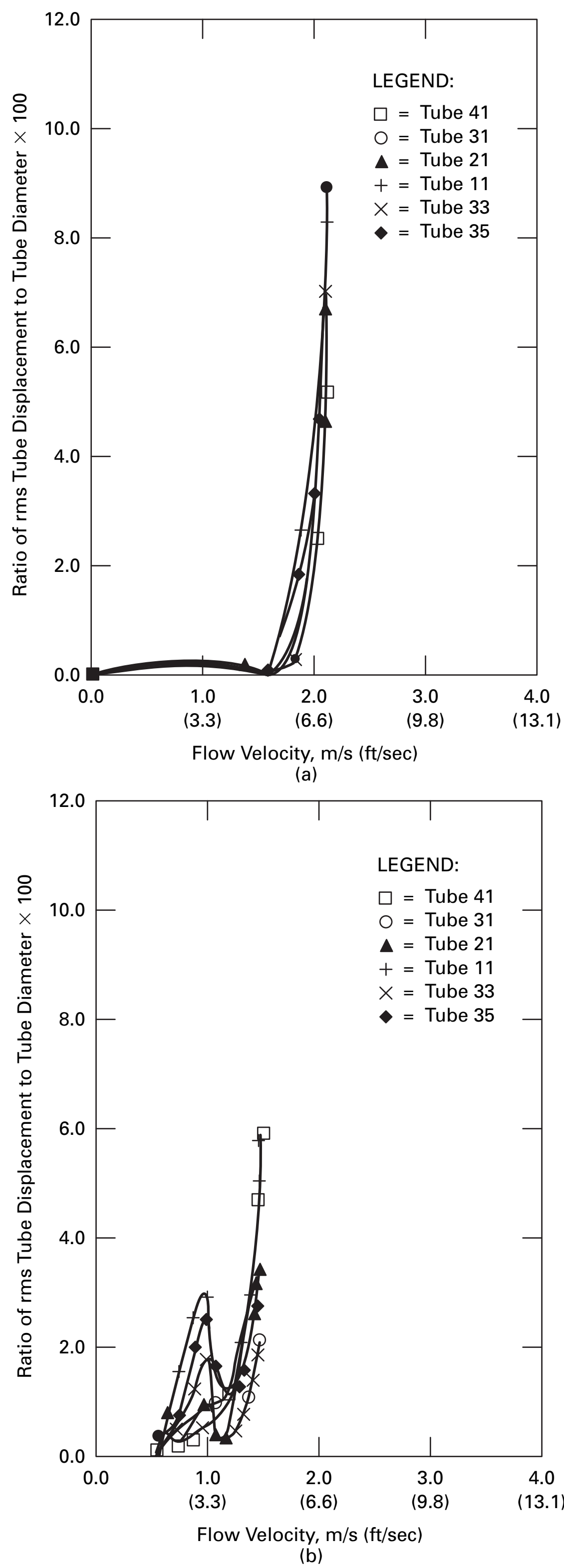
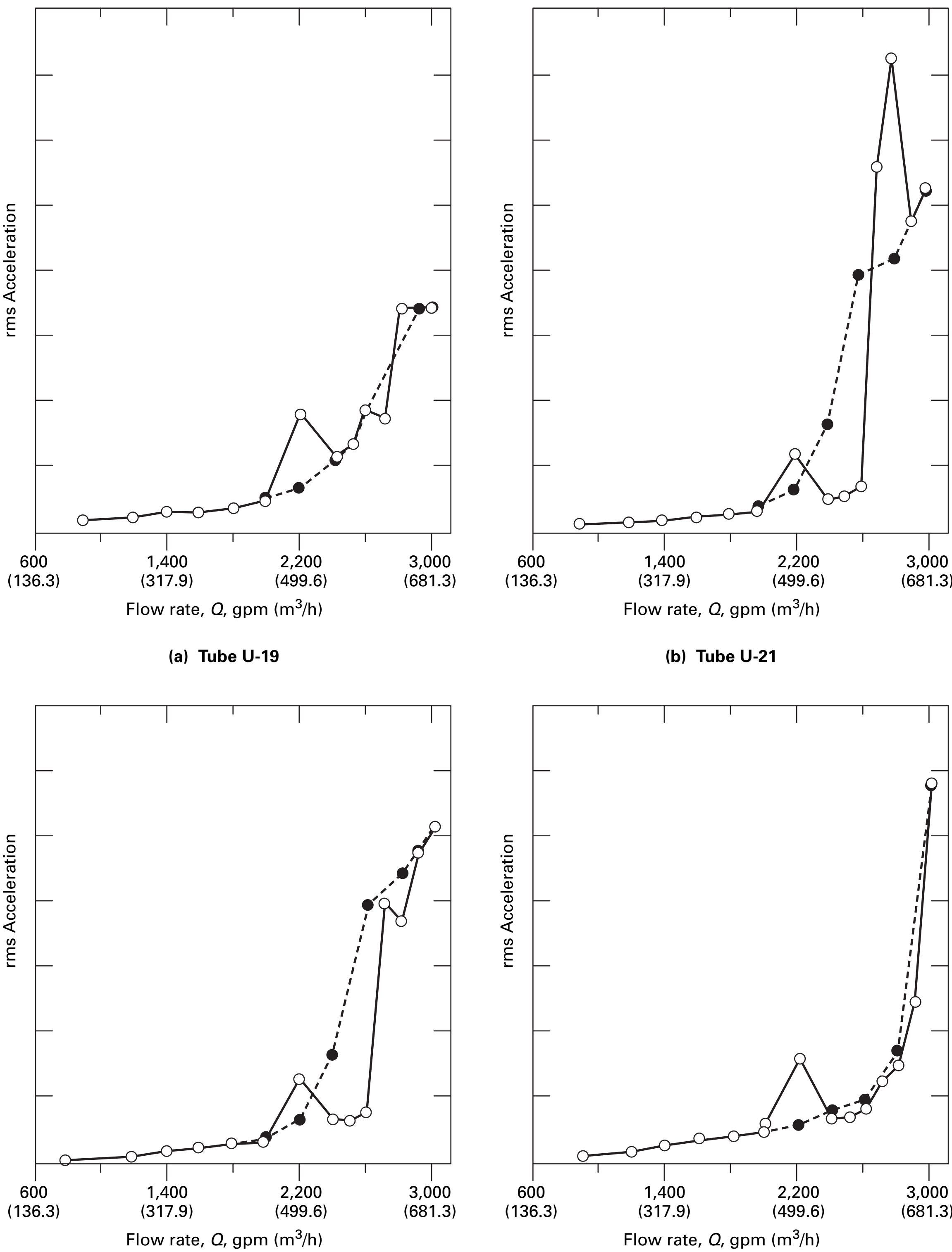


Fig. E-5 Response Versus Flow Rate for Four Tubes in Industrial Size Shell-and-Tube Heat Exchanger (Open Symbol: Increasing Flow; Solid Symbol: Decreasing Flow)



(a) Tube U-19

(b) Tube U-21

(c) Tube V-20

(d) Tube U-5

Fig. E-6 Displacement Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test

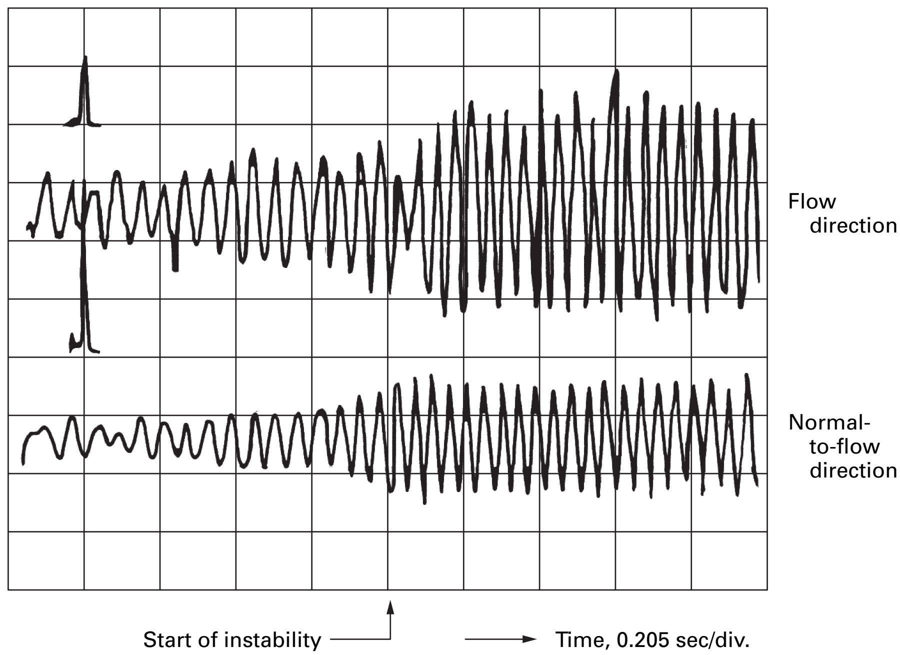
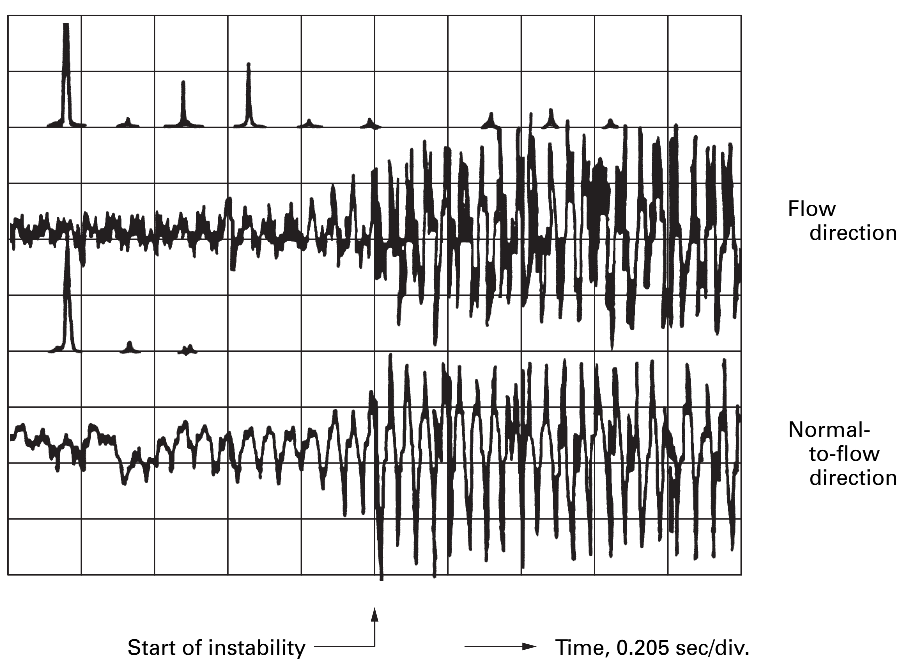


Fig. E-7 Acceleration Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test



E-4.4 Tube Trajectory

In situations in which an accelerometer pair, with axes in an orthogonal orientation, is employed, patterns of the spatial trajectories (x-y motion) of a tube, obtained from time histories, can be useful in interpreting the dynamic response and onset of instability. A typical example is given in Fig. E-8 [see subpara. E-6(e)]; the trajectories are from an accelerometer pair located in a tube of an industrial-size, shell-and-tube heat exchanger. At a flow rate of 1,640 gal/min (372.4 m^3/h), the pattern of tube motion is random, and the amplitude of response is low [peak-to-peak amplitude of 6 mils (0.15 mm)]. At approximately the instability flow rate [1,950 gal/min (442.8 m^3/h)], the motion becomes organized into a nearly straight-line pattern primarily in the transverse-to-flow direction; the peak-to-peak amplitude has increased to approximately 60 mils (1.5 mm), 10 times that of the lower flow rate. As the flow rate is increased further, to 2,140 gal/min (486.0 m^3/h), the tube begins to whirl and to impact adjacent tubes; the peak-to-peak amplitude is now greater than 240 mils (6.1 mm) with the motion limited by impacting.

E-4.5 Frequency Response Data

The critical flow velocity can be thought of as the flow velocity defining the transition from turbulent buffeting to fluidelastic instability. When a tube bundle is immersed in a dense fluid such as water, fluid structure coupling occurs, which gives rise to a broad band of closely spaced frequencies, centered about what would be the natural frequency of an isolated tube in the fluid. At flow velocities below the critical value, turbulent buffeting is the dominant excitation mechanism. It excites this broad range of coupled frequencies, as evidenced from the response power spectral density curves. On the other hand, the vibration at instability will typically be at a well-defined, single frequency (corresponding to the instability mode).

In application of this method, the vibration response time histories are processed on a Fast Fourier Transform Analyzer to obtain power spectral density (PSD) representations of the data. The flow velocity (or flow rate) at which the response PSD changes from a relatively broadband spectrum to a narrowband (single-frequency) spectrum is defined as the critical flow velocity (see, for example, Nonmandatory Appendix A of this Part, Fig. A-2).

Figure E-9 is from a vibration test in which the flow was both increased and decreased in incremental steps [see subpara. E-6(e)]. Response spectra for flow rates from 900 gal/min to 2,600 gal/min (204.4 m^3/h to 590.5 m^3/h) are representative of turbulent buffeting excitation. The sharp, single-frequency response at 2,700 gal/min (613.2 m^3/h) is interpreted to indicate that the transition from turbulent buffeting to fluidelastic instability took place in the range 2,600 gal/min to 2,700 gal/min (590.5 m^3/h to 613.2 m^3/h). The multiple-frequency response at flow rates from 2,800 gal/min to 3,000 gal/min (635.9 m^3/h to 681.3 m^3/h) is expected to be the result of impacting with adjacent tubes and/or rattling in the baffles. As the flow rate is decreased from 3,000 gal/min (681.3 m^3/h), it is interesting to observe that a well-defined, single-frequency instability mode frequency appears once again. The dropout of instability or transition from instability to a dominant turbulence response occurs between 2,200 gal/min and 2,000 gal/min (499.6 m^3/h and 454.2 m^3/h), as indicated by the change in character of the response spectra. These results are in good agreement with the results from sensory observations.

In general, this method is felt to be reasonably reliable for heat exchangers with dense shell-side fluids. However, engineering judgment is still required in situations in which the broadband spectra associated with turbulent buffeting "narrow" significantly before becoming extremely sharp or when the amplitude and/or frequency change abruptly due to a change in the tube support configuration. Also, in cases in which the instability is very abrupt, the large amplitudes might initiate impacting that, in turn, will be represented as a broad frequency range on the PSD. In this case, the single-frequency spike representative of instability might not be detected.

Each of the above methods are somewhat subjective and dependent on engineering judgment. In determining the critical flow rate for a heat exchanger bundle, it is advisable to employ all the available methods and to compare the results from one against those from another. In particular, since it is practically possible to instrument only a small percentage of the large number of tubes in the bundle, it is necessary to scan the tube ends to identify those tubes and groups of tubes that first experience large-amplitude motion. Selected tubes, from those so identified, can then be instrumented, and one or more of the other methods, which are dependent on response data, can be applied to determine more accurately the onset and dropout (with decreasing flow) of instability.

E-5 TUBE SUPPORT PLATE INTERACTION

Clearances between tubes and tube support plate holes are inherent in the design of heat exchangers; it is common for the tube holes to be drilled 0.4 mm to 0.8 mm over the outside diameter of the tubes. Depending on initial tube straightness, mechanical fit-up, and operating conditions, it is possible for a tube to be effectively centered within the tube support plate hole. In such cases the tube support plate does not provide effective support, and the tube may vibrate due to turbulence excitation or experience instability in a so-called tube support plate inactive mode. Steady drag is an important consideration. The potential for occurrence of this phenomenon is increased for heat exchangers

Fig. E-8 Tube Vibration Patterns From X-Y Probe and Test of Industrial Size Shell-and-Tube Heat Exchanger

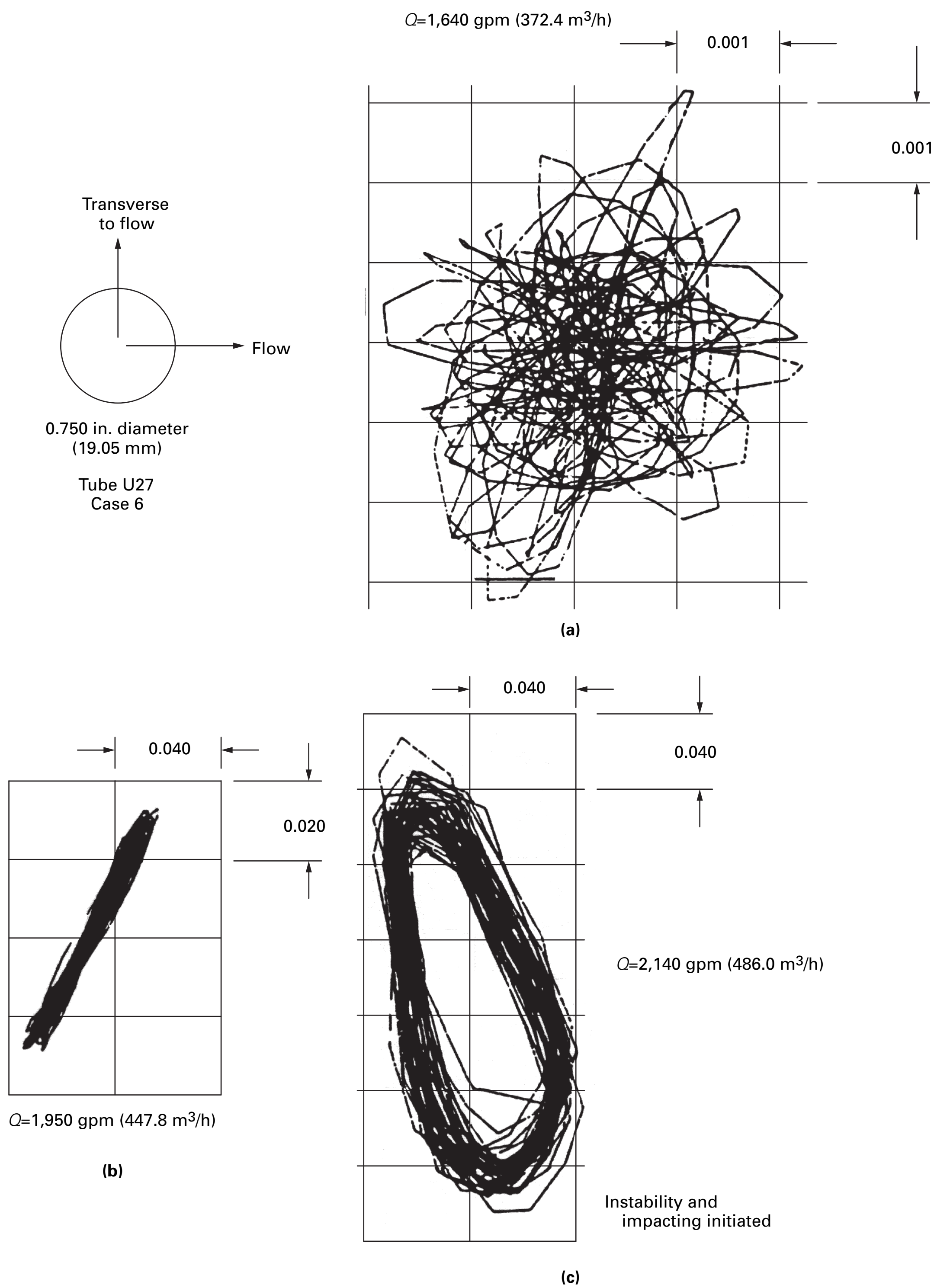


Fig. E-9 Frequency Response Curves for Tubes in Industrial Size Shell-and-Tube Heat Exchanger

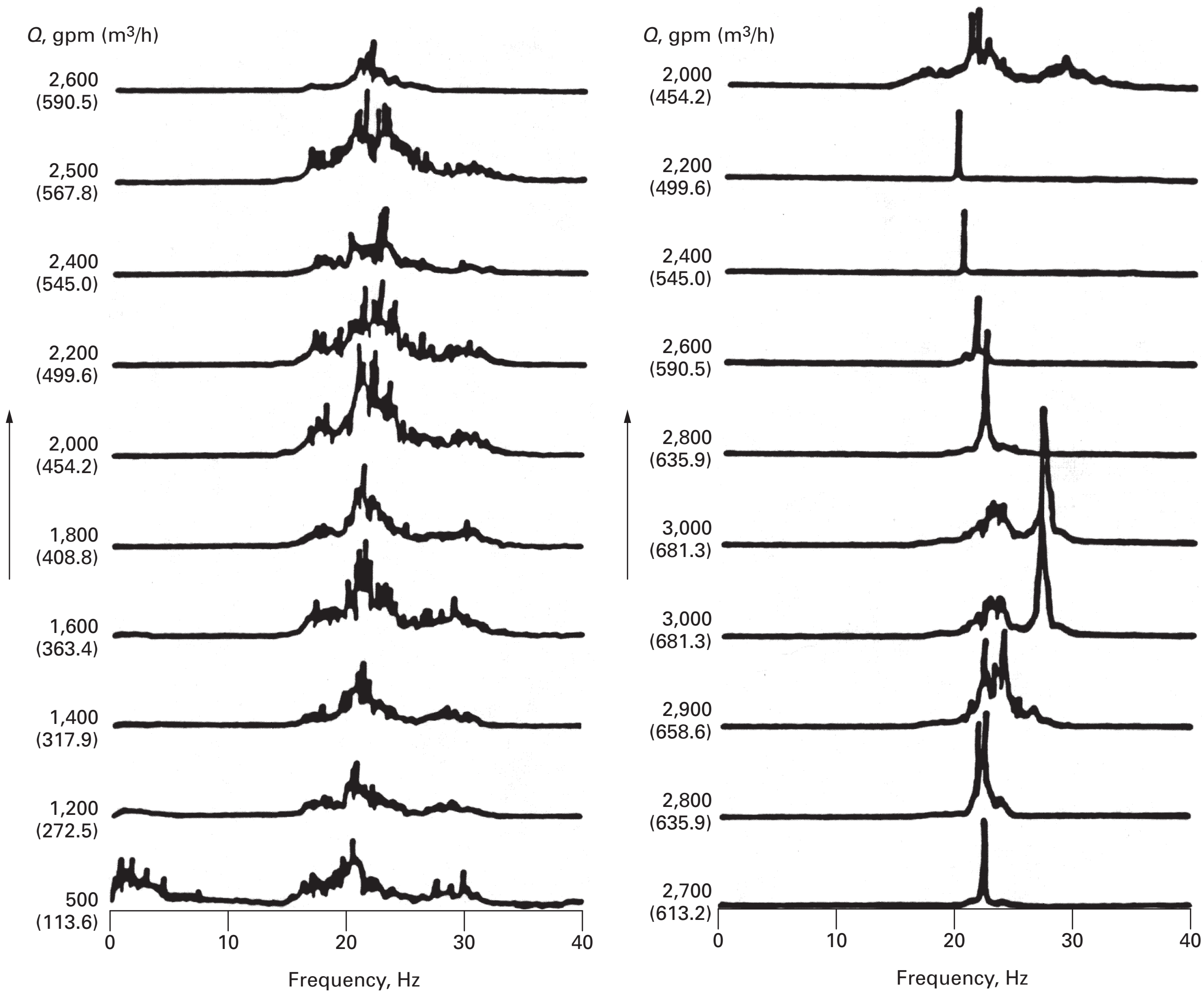
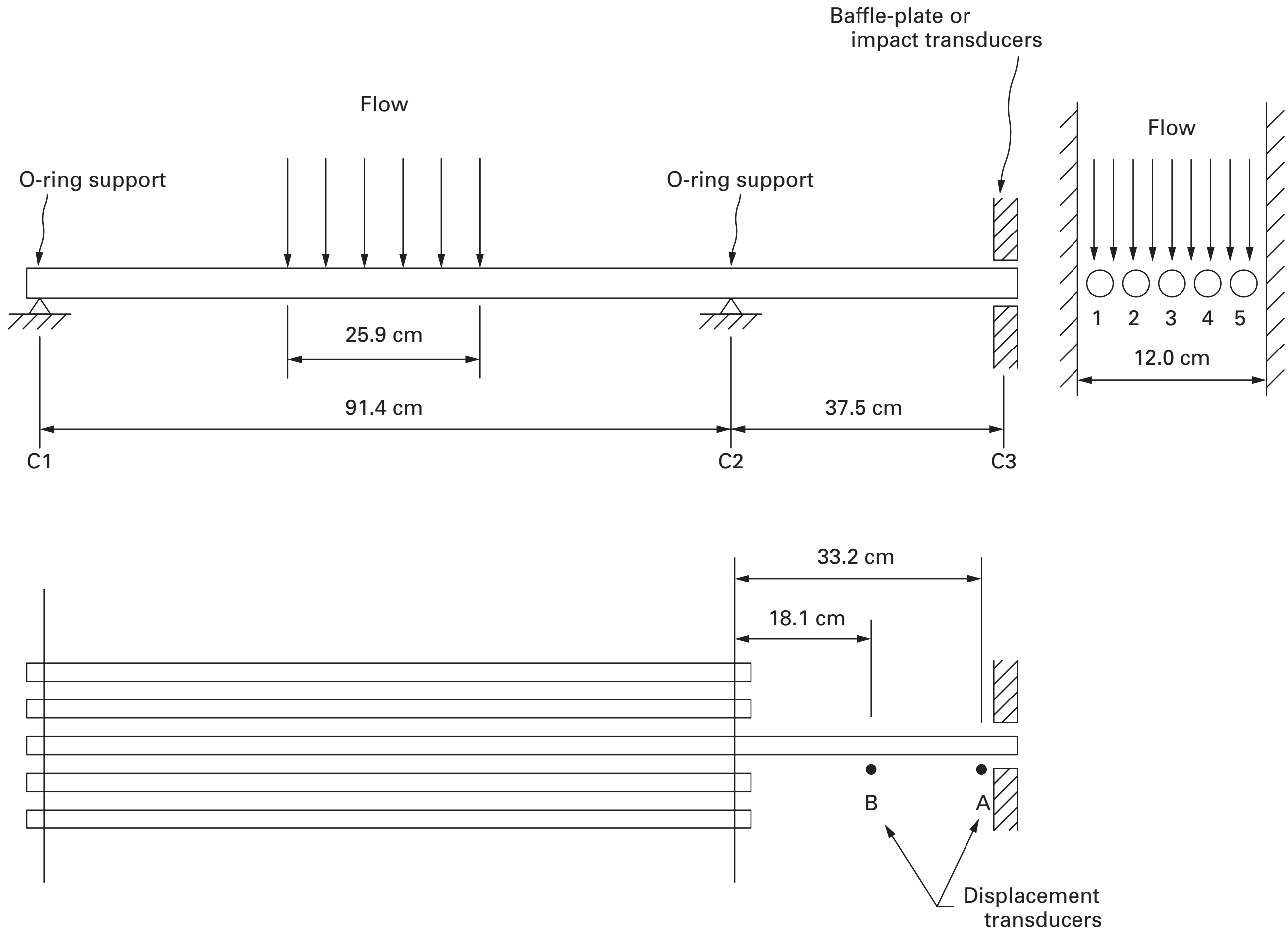


Fig. E-10 Schematic of Test Setup



with relatively large tube to support plate hole clearances and short (stiff) spans (tubes with long, inherently flexible spans will respond to the steady drag exerted by the shell-side flow and will typically be forced against the support plate).

This vibration of a tube in a tube support plate inactive mode has been observed in the field and in laboratory tests. Discussions of effects of tube and support interaction due to turbulence excitation are included in the references in subparas. E-6(h) through E-6(m). Laboratory results obtained regarding the effects of clearances on fluidelastic response of tubes are discussed below.

The laboratory setup and typical results are given in Figs. E-10 through E-13 [see subpara. E-6(n)]. Again, initial clearance, initial preload for the case of initial clearance equal to zero, and steady drag are all important, contributing factors. Figure E-11 is a plot of tube response as a function of flow velocity for two measurement locations as indicated in Figs. E-10 and E-11. It clearly shows the existence of the two instability types. Figure E-12 gives representative frequency response spectra as a function of flow velocity. Sample time histories corresponding to selected flow rates are given in Fig. E-13. The data are presented as a further aid to the user in interpretation of data obtained from vibration tests.

E-6 REFERENCES

The following is a list of publications referenced in this Appendix:

(a) R. T. Hartlen and W. Jaster, "Flow-Induced Vibration of Tubes in Operational Heat Exchangers: Some Experiences in Detection and Diagnosis by Vibroacoustics Measurements," ASME HTD-Vol. 9, Flow-Induced Heat Exchanger Tube Vibration (1980)

(b) R. B. Wilson and J. E. Gillett, "Vibroacoustic Method to Detect Heat Exchanger Tube Vibrational Impacting," ASME 84-NE-1 (1984)

(c) B. M. H. Soper; J. M. Chenoweth and J. R. Stenner, eds.; "The Effect of Tube Layout on the Fluidelastic Instability of Tube Bundles in Cross Flow,"

Fig. E-11 Root Mean Square (rms) Tube Displacements As Function of Flow Velocity (Diametral Gap of 1.02 mm)

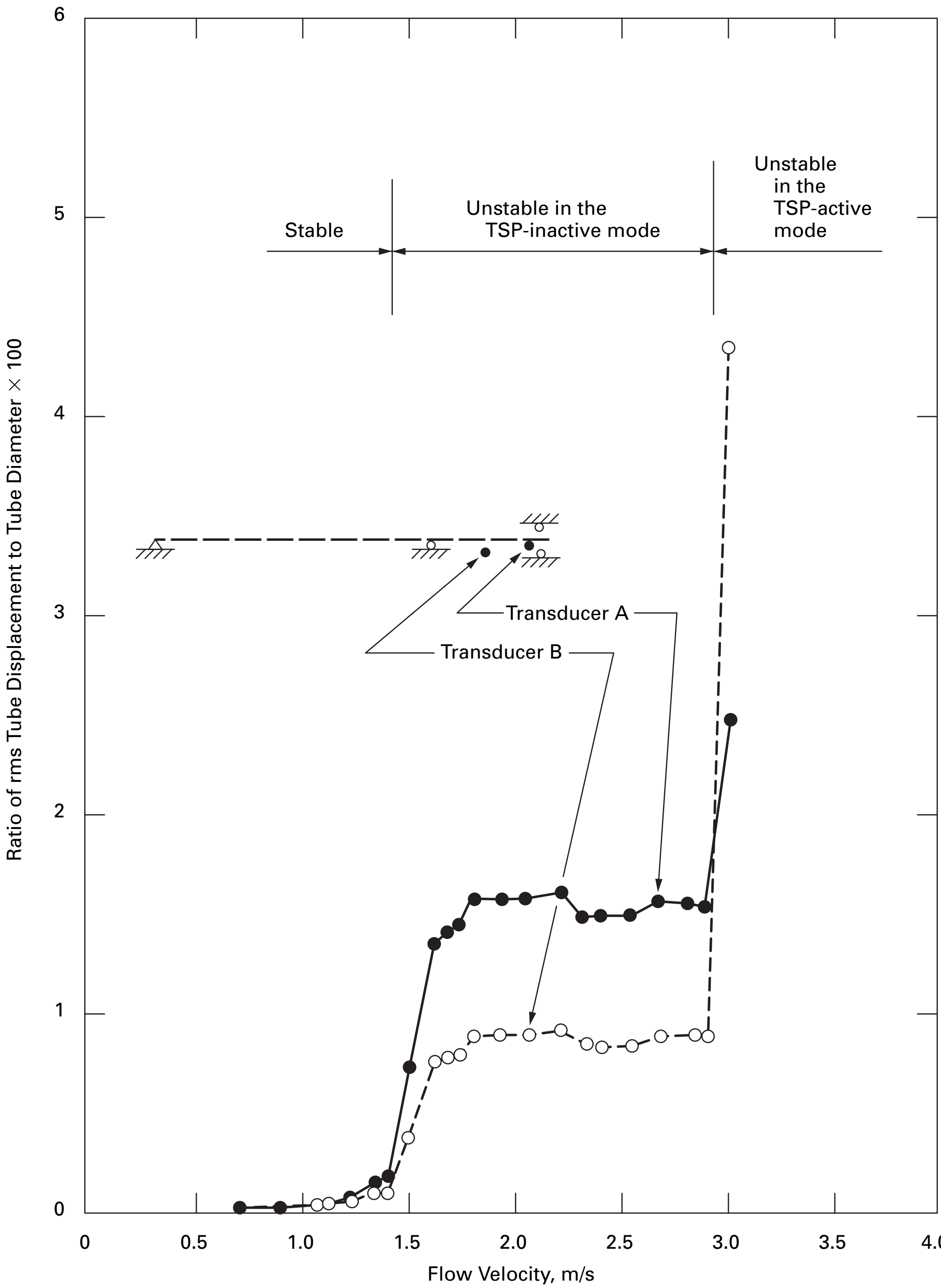


Fig. E-12 Frequency Spectra of Tube Displacement at Location "A" (Diametral Gap of 1.27 mm)

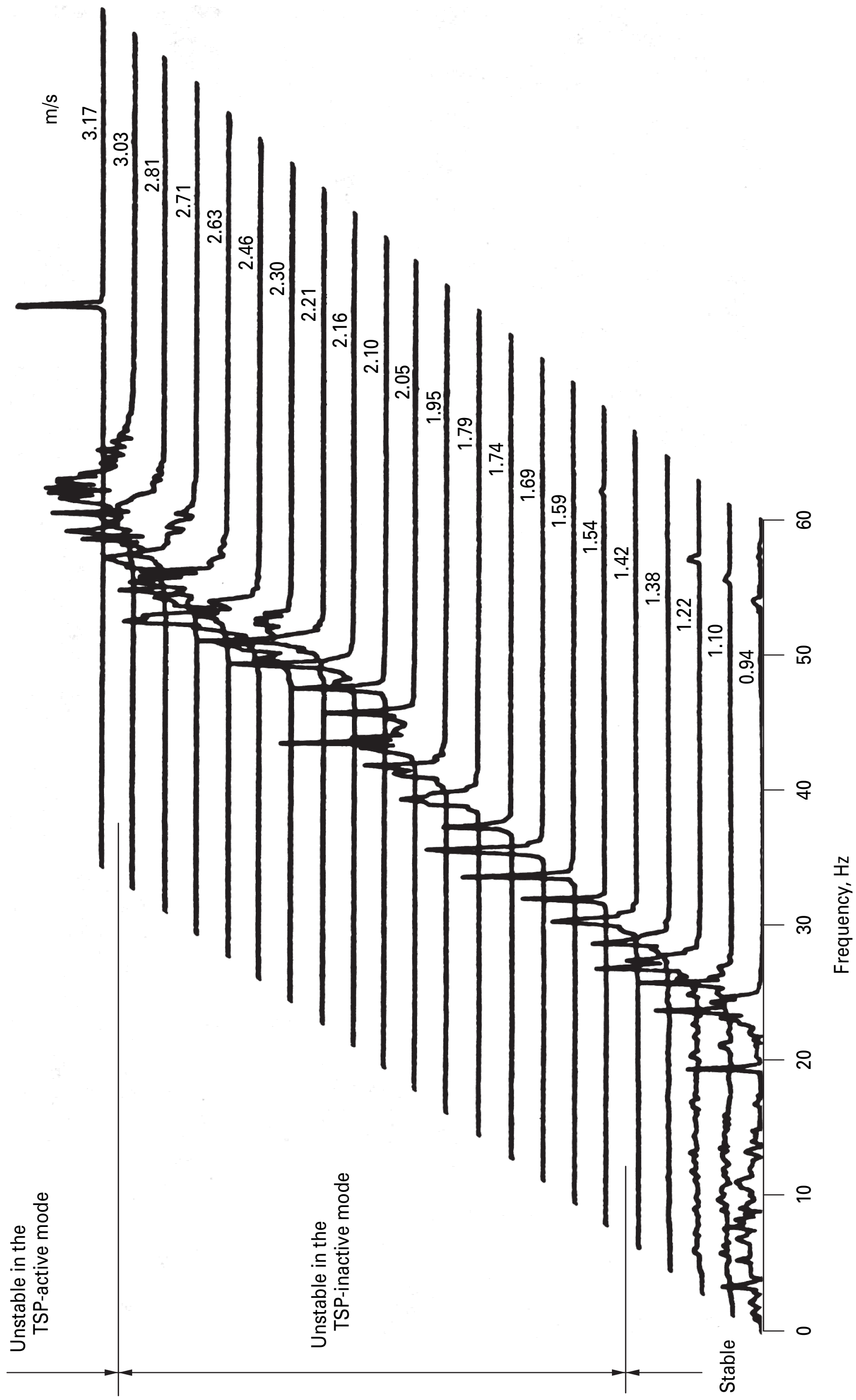
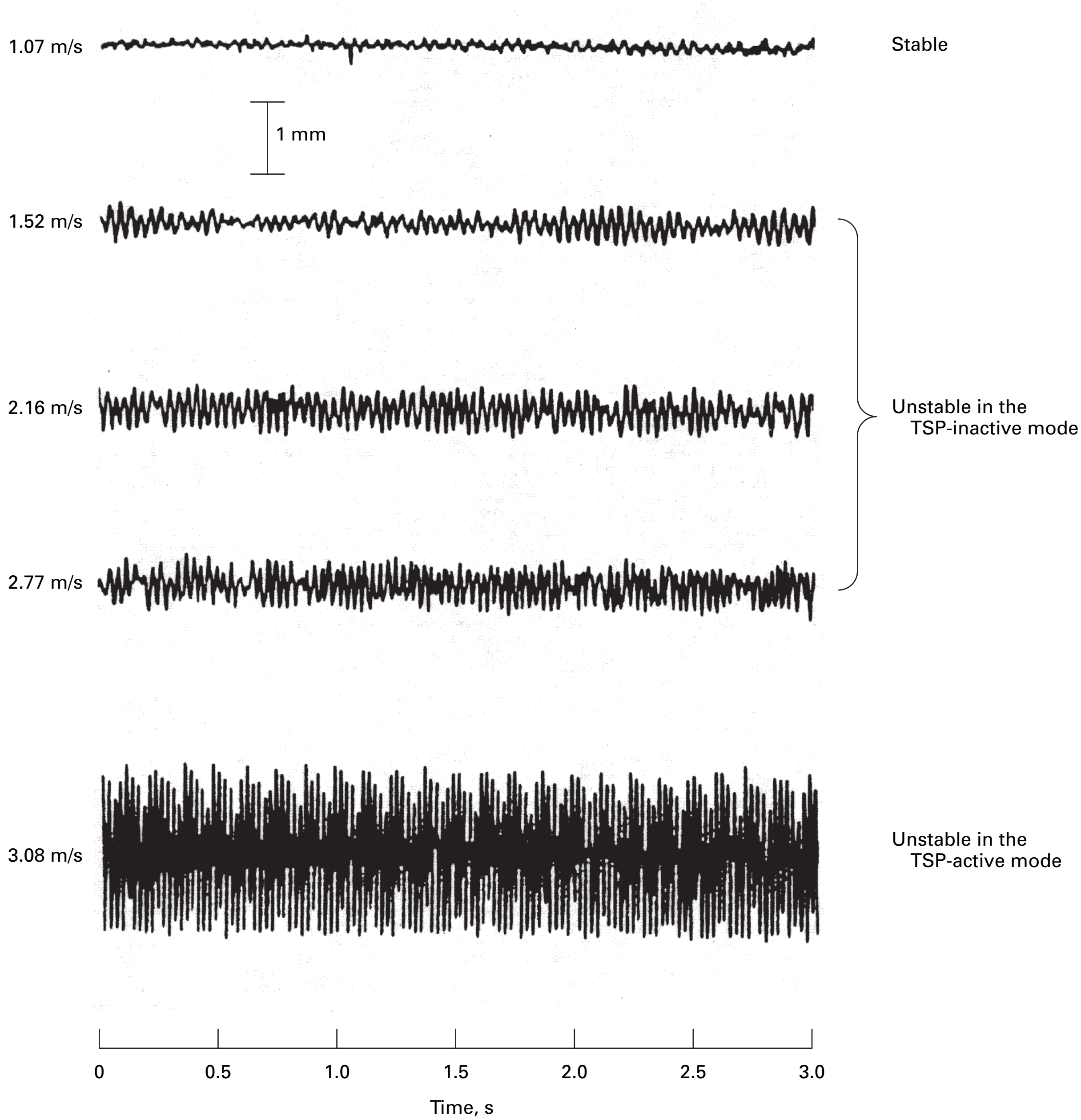


Fig. E-13 Tube Displacement Time Histories at Location "A" (Diametral Gap of 0.51 mm)



Flow-Induced Heat Exchanger Tube Vibration, ASME HTD-Vol. 9 (1980): 1–9

(d) J. A. Jendrzejczyk, personal communication (Argonne National Laboratories, 1984)

(e) H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger (90 Deg. Square Layout)," ANL Report ANL-83-10 (February 1983)

(f) H. C. Yeung and D. S. Weaver, "The Effect of Approach Flow Direction on the Flow-Induced Vibrations of a Triangular Tube Array," ASME Journal of Vibration, Acoustics, Stress, and Reliability, Vol. 105 (1981): 76–82

(g) H. Halle, personal communication (Argonne National Laboratory, 1984)

(h) R. Bouecke and G. Schuctanz, "Experience With KWU Steam Generators," Part 2, KWU Steam Generator Concept with Economizer, NEA/CSNI-UN-IPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 6.3

(i) T. M. Frick, T. E. Sobek, and J. R. Reavis, "Overview on the Development and Implementation of Methodologies to Compute Vibration and Wear of Steam Generator Tubes," Flow-Induced Vibration in Heat Exchangers, Symposium on Flow-Induced Vibration, ASME Winter Annual Meeting (New Orleans, LA; Dec. 9–13, 1984)

(j) K. H. Haslinger and D. A. Steininger, "Steam Generator Tube/Tube Support Plate Interaction Characteristics," Symposium on Flow-Induced Vibration, ASME Winter Annual Meeting (New Orleans, LA; December 9–14, 1984): Vol. 3

(k) P. J. Hofmann, T. Schettler, and D. A. Steininger, "Pressurized Water Reactor Steam Generator Tube Fretting and Fatigue Wear Characteristics," ASME PVP-2, ASME PVP Conference (Chicago, July 21–24, 1986)

(l) M. J. Pettigrew and P. L. Ko, "A Comprehensive Approach to Avoid Vibration and Fretting in Shell-and-Tube Heat Exchangers," Flow-Induced Vibration of Power Plant Components, ASME PVP-41 (August 1980)

(m) N. R. Singleton, "Design Resolution of Westinghouse Reheat Steam Generator Flow-Induced Vibration Concerns," NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 1.6

(n) S. S. Chen, J. A. Jendrzejczyk, and M. W. Wambsganss, "Dynamics of Tubes in Fluid With Tube-Baffle Interaction," ASME Pressure Vessel Technology, Vol. 107 (1985): 7–17

Part 11, Nonmandatory Appendix F
Vibration Acceptance Guidelines

F-1 INTRODUCTION

For some heat exchangers, a review of the data that reveals no indications of strong vibration may be an adequate basis for acceptance. In some cases, periodic inspection for wear, by eddy current testing, for example, may be appropriate [see subpara. F-6(a)].

Guidelines for an initial assessment are provided in section F-2. Possible follow-up actions are listed in section F-3. If a more complete assessment is justified by the importance of the heat exchanger, previous experience, or unacceptable results from the initial evaluation, a more detailed program may be required. Information in the literature that may support a detailed assessment of the wear rate implied by tube vibration measurements are summarized in section F-4. Sources of background information relative to external surveys are provided in section F-5.

F-2 GUIDELINES FOR INITIAL ASSESSMENT

Data evaluation results for which further action is recommended are described below.

(a) Excessive Fatigue Stresses. Review the data to determine tube displacement shapes and amplitudes. Calculate and evaluate fatigue stresses.

(b) Contact Between Adjacent Tubes. Determine maximum zero-to-peak tube vibration displacement amplitudes. Compare these amplitudes to tube-to-tube clearances to ensure that the likelihood of contact is adequately low.

(c) Frequent Impacting Between the Tube and Tube Support. Although tube vibration may be acceptable with some impacting, if continuous or intermittent impacting is present, further action (such as listed below) is recommended unless information is available that indicates this is not necessary. Sample time histories and techniques for the detection of impacting are provided in Nonmandatory Appendix E of this Part.

(d) Presence of Fluidelastic Vibration. Review the data for indications of vibration caused by fluidelastic excitation. Fluidelastic vibration is usually evidenced by an increase in the rate of change of vibration level as flow rate is increased (although this could also be a result of vibration in a different mode due to a change in the tube support pattern). Indications that the tube is undergoing circular motions or sharpening of the frequency spectrum also can indicate that the tube is vibrating due to fluidelastic excitation (see Nonmandatory Appendix E of this Part). Although the existence of fluidelastically excited tube vibration does not necessarily imply an unacceptable wear rate, this mechanism is frequently the cause of excessively high vibration levels.

F-3 FOLLOW-UP ACTIONS

One or more of the following can be implemented if vibration levels are not acceptable:

(a) Review existing design information and perform additional analysis as indicated to attempt to identify the cause and possible remedial actions.

(b) Limit the heat exchanger flow rate.

(c) Install modifications to reduce vibration levels and retest to verify adequacy.

(d) If it can be shown that an acceptably small number of tubes are considered to be potentially unacceptable, these tubes may be removed from service with consideration of the need for precautions against subsequent damage.

(e) Perform a detailed assessment.

F-4 METHODS FOR DETAILED WEAR ASSESSMENTS

Several approaches that may support detailed assessment of the wear implied by accelerometer data and support the development of more specific acceptance criteria are in the literature [see the references in subparas. F-6(a) through F-6(g)].

These references report the following:

(a) the use of laboratory flow model wear measurements to project the wear of a specific heat exchanger with subsequent field verification

(b) the use of nonlinear modal analysis and experimental fluctuating force data to predict flow-induced tube motion and wear rate

(c) work on the development of correlations between tube motion characteristics and wear rate

(d) the correlations of tube-tube support interaction forces with wear rate

(e) correlation of field wear data and field accelerometer vibration measurements for wear evaluation of similar units

Extensive information is needed for the use of these approaches. The suitability of these methods for a particular heat exchanger should be determined on a case-by-case basis.

F-5 GUIDELINES FOR THE EVALUATION OF EXTERNAL VIBRATION LEVELS

In the absence of specific criteria for the equipment being tested, references may provide guidance for the evaluation of external vibration levels.

(a) Hartlen, Elmaraghy, and Slingerland, "Vibration Velocity as a General Severity Criterion," Canadian Electric Association Spring Meeting (March 1982).

This paper presents the rationale for using vibration velocity as the most generally useful parameter, and for expecting acceptance criteria to be roughly independent of the particular system details.

(b) DIN 4150, the German code addressing vibration in structures. There are three parts: Part 1, principles, predetermination, and measurement of the amplitude of oscillations; Part 2, influence on persons in buildings; and Part 3, influence on construction (in German).

(c) Part 3 of this document, ASME OM-S/G-2003, Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems.

Several methods for evaluating the severity of piping system vibrations are provided in this Part.

F-6 REFERENCES

The following is a list of publications referenced in this Nonmandatory Appendix:

(a) "Evaluation of Eddy-Current Procedures for Measuring Wear Scars in Preheat Steam Generators," Electric Power Research Institute Final Report, NP-3928 (April 1985)

(b) R. Bouecke and G. Schuctanz, "Experience With KWU Steam Generators," Part 2, KWU Steam Generator Concept With Economizer, NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 6.3

(c) T. M. Frick, T. E. Sobek, and J. R. Reavis, "Overview on the Development and Implementation of Methodologies to Compute Vibration and Wear of Steam Generator Tubes," Symposium on Flow-Induced Vibration in Heat Exchangers, ASME Winter Annual Meeting (New Orleans, LA; December 9–13, 1984)

(d) K. H. Haslinger and D. A. Steininger, "Steam Generator Tube/Tube Support Plate Interaction Characteristics," Symposium on Flow-Induced Vibration in Heat Exchangers, ASME Winter Annual Meeting (New Orleans, LA; December 9–14, 1984): Vol. 3

(e) P. J. Hofmann, T. Schettler, and D. A. Steininger, "Pressurized Water Reactor Steam Generator Tube Fretting and Fatigue Wear Characteristics," ASME PVP-2, ASME PVP Conference (Chicago, IL; July 21–24, 1986)

(f) M. J. Pettigrew and P. L. Ko, "A Comprehensive Approach to Avoid Vibration and Fretting in Shell-and-Tube Heat Exchangers," Flow-Induced Vibration of Power Plant Components, ASME PVP-41 (August 1980)

(g) N. R. Singleton, "Design Resolution of Westinghouse Reheat Steam Generator Flow-Induced Vibration Concerns," NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 1.6

Part 11, Nonmandatory Appendix G Installation of Strain Gages

Significant operations are required to install strain gages on the inner surface of tubes. Prior to installing the gages, the lead wires are attached to each gage to accommodate a three-wire bridge; two wires are attached to one strain gage terminal and one wire to the other terminal. The inside surface of the tube is cleaned using an expandable brake cylinder hone. During this operation, care must be taken to ensure that the interior surface of the tube is not damaged.

After honing, the surface should be inspected with a borescope. The surface is then cleaned using gauze swabs saturated with an appropriate cleaner. After the tubes are thoroughly cleaned, the interior surface of the tube is heated. Heating the tube surface ensures that it is moisture-free and accelerates the curing of the strain gage adhesive. The strain gage is fixed to the surface of a length of surgical tubing. One end of the tube is plugged and the other end attached to a regulated air supply. The strain gage is coated with a few drops of glue. The rubber tube is inserted into the tube.

Once the strain gage is positioned, the rubber tube is inflated. After the glue cures, the rubber insertion tool is deflated and removed. The resistance of the gage must be checked and the gage installation examined using a borescope. If the installation is acceptable, then the gage is waterproofed and spliced to the signal cable.

Part 14
Vibration Monitoring of Rotating Equipment in Nuclear Power Plants

1 INTRODUCTION

Existing standards provide rules for the proper use of vibration monitoring instrumentation, acceptance testing of equipment at the manufacturer's facility, and to some extent, in situ evaluation of mechanical vibration. There is, however, a need for guidance for in situ vibration monitoring of rotating equipment for the purpose of scheduling or extending maintenance periods. The intent of this Part is to fill that need. The main paragraphs of this Guide are as follows:

(a) Section 4, Vibration Monitoring, describes periodic and continuous monitoring and important considerations that affect quality of acquired data.

(b) Section 5, Establishing the Baseline, describes collection and use of baseline data.

(c) Section 6, Establishing Vibration Limits, provides a procedure and criteria for determining when maintenance should be scheduled for rotating equipment.

(d) Section 7, Data Acquisition, presents the recommended practices for installation of data acquisition instrumentation.

(e) Section 8, Hardware, describes the various types of transducers and continuous monitoring systems and recommends the characteristics that should be considered when selecting transducers and related equipment.

(f) Section 9, Diagnostics, provides guidelines for performing vibration analysis and identifying possible causes of increasing or excessive vibration.

1.1 Scope

This Part provides guidance for preservice and inservice vibration monitoring of rotating equipment used in light-water reactor (LWR) power plants. This Part recommends monitoring methods, intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Purpose

The purpose of this Part is to present guidelines for implementing a vibration monitoring program that will provide vibration data that can be used for the following:

(a) to compare the vibration level of equipment to equipment of the same type with similar mounting conditions or to establish vibration guidelines and standards

(b) to detect changes in an equipment's vibration level that indicate that the equipment is approaching an inoperable condition or when continued operation might damage the machine

(c) to assist in the development of a predictive maintenance program by providing the basis for appropriate scheduling of maintenance

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

absolute measurement: measurement of machine vibration relative to a fixed point in free space.

acceleration: a vector that specifies the time derivative of velocity.

amplitude: the maximum value of a quantity.

diagnostics: methods used to identify sources and/or causes of vibrations from data gathered using vibration-monitoring and analytical equipment.

displacement: a vector quantity that specifies the change of position of a body, or particle, with respect to a reference frame.

electrical runout: a source of error on the output signal of a noncontacting probe system resulting from nonuniform electrical conductivity/resistivity/permeability properties of the observed material or from the presence of a local magnetic field at a point on the shaft surface.

filter (electronic): a device for separating components of a signal on the basis of their frequency. It allows components in one or more frequency bands to pass relatively unattenuated and it attenuates components in other frequency bands.

frequency range: the frequency range over which the transducer (system) sensitivity does not vary more than a stated percentage from the rated sensitivity.

frequency response: the output signal expressed as a function of the frequency of the input signal. The frequency response is usually given graphically by curves showing the relationship of the output signal and, where applicable, phase shift or phase angle as a function of frequency.

in situ: in the natural or original installed (or operational) position.

natural frequency: frequency of free oscillation of a system.

noncontacting probe: a probe that has the capability to measure the distance between the probe face and a surface such as that of a shaft. Sometimes also referred to as "proximity probe."

phase angle: the fractional part of a period through which a sinusoidal quantity has advanced as measured from a value of the independent variable as a reference.

relative displacement: the relative displacement between two points is the vector difference between the absolute displacement vectors of the two points.

resonance: occurs when a system is forced to oscillate at a natural frequency of the system.

root mean square: the root mean square (rms) value of a set of numbers is the square root of the average of their squared values.

sensitivity: the ratio of a specific output quantity to a specific input quantity.

transducer: a device that measures dynamic motion of a system and produces an electrical output signal with amplitude that is proportional to the motion measured.

velocity: a vector that specifies the time-derivative of displacement.

3 REFERENCES

(15) 3.1 Referenced Standards

The following is a list of standards referenced in this Part:

ANSI S2.17-1980, American National Standard Techniques of Machinery Vibration Measurement
Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036

API 670-1976, Non-Contacting Vibration and Axial Position Monitoring System
API 678-1981, Accelerometer-Based Vibration Monitoring System
Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005-4070

ISO 2041-1975, Vibration and shock — Vocabulary
ISO 2372-1974, Mechanical vibration of machines with operating speeds from 10 to 200 rev/s — Basis for specifying evaluation standards
ISO 2373-1974, Mechanical vibration of certain rotating electrical machinery with shaft heights between 80 and 400 mm — Measurement and evaluation of the vibration severity
ISO 3945-1977, Mechanical vibration of large rotating machines with speed range from 10 to 200 rev/s — Measurement and evaluation of vibration severity in situ
Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

Standards for Centrifugal, Rotary, and Reciprocal Pumps, 4th Edition
Publisher: Hydraulic Institute (HI), 9 Sylvan Way, Parsippany, NJ 07054 (www.pumps.org)

3.2 Referenced Publications

References listed below can be used as aids in developing or performing rotating-equipment-related vibration monitoring activities.

(a) Bloch, Heinze P., "Practical Machinery Management for Process Plants, Vol. I, Improving Machinery Reliability," Gulf Publishing Co., Houston, Texas, 1983

(b) "Computerized PPM Systems," *Compressed Air Magazine*, July 1984. pp. 21–26

(c) Dodd, V. Ray, and East, John R., "The Third Generation of Vibration Surveillance," ASME paper presented at 37th Petroleum Mechanical Engineering Workshop and Conference, Dallas, Texas, September 1981

(d) Gilstrap, Mark, "Transducer Selection for Vibration Monitoring of Rotating Machinery," *Sound and Vibration*, February 1984

(e) Goldmen, Steve, "Periodic Machinery Monitoring: Do It Right," *Hydrocarbon Processing*, August 1984, pp. 51–56

(f) Hewlett-Packard, "Dynamic Signal Analyzer Application-Effective Machinery Maintenance Using Vibration Analysis," Hewlett-Packard Application Note 243-1, 1983

(g) Jackson, Charles, "The Practical Vibration Primer," Gulf Publishing Co., Houston, Texas, 1979

(h) Maxwell, A.S., "Experience With Use of Vibration Standards," presented at 6th Machinery Dynamics Seminar, Sept. 22 and 23, 1980, National Research Council of Canada, Reprint by Bentley Nevada Corp., Minden, Nevada, NO. L0477-00, 1982

(i) Mitchell, John S., "An Introduction to Machinery Analysis and Monitoring," PennWell Books, Tulsa, Oklahoma, 1981

(j) Mitchell, John S., "How to Develop a Machinery Monitoring Program," *Sound and Vibration*, February 1984

(k) Sohre, John S., "Operating Problems With High Speed Turbomachinery, Causes and Correction," ASME paper presented at the ASME Petroleum Mechanical Engineering Conference, September 23, 1968, Dallas, Texas

(l) Taylor, James I., "Determination of Antifriction Bearing Condition by Spectral Analysis," The Vibration Institute, Clarendon Hills, Illinois, 1978

Table 1 Comparison of Periodic and Continuous Monitoring and Relative Advantages

Periodic Monitoring	Continuous Monitoring
1. Less capital investment	1. Provides primary machinery protection from catastrophic failure through local/remote annunciation and/or automatic machine trip and shutdown
2. Less data acquisition equipment maintenance	2. May provide earlier detection of impending mechanical problems
3. Less manpower to ensure calibration of data acquisition system	3. Tracks vibration over all operating conditions
4. More data can be obtained from a machine at relatively small increase in cost	4. Can be used with other data accumulation/reduction devices (computers, data loggers, etc.)
5. More measurement locations	5. Continuous severity assessment
6. More vibration units of measurement (displacement, velocity, or acceleration) available from a single transducer	6. Rate of increase of vibration more readily determined
	7. Abrupt changes such as blade loss can be more promptly recognized
	8. Fewer manpower requirements to acquire data
	9. Data obtained in a more consistent manner; location direction and transducer mounting are repeatable
	10. Fewer measurement errors

(m) Taylor, James I., "Identification of Gear Defects by Vibration Analysis," The Vibration Institute, Clarendon Hills, Illinois, 1979

4 VIBRATION MONITORING

4.1 Types of Monitoring

Vibration monitoring involves the measurement of overall vibration parameters (displacement, velocity, or acceleration) for which some evaluation can be made, either through comparison to a standard, a manufacturer's specification, or previously acquired data from the same or similar equipment. In its broader definition, vibration monitoring can include other related parameters such as thrust, position, or differential expansion. This Part provides for the periodic and continuous monitoring of rotating equipment. The relative advantages of each type of monitoring are listed in Table 1.

Periodic vibration monitoring is the process of measuring the vibration of equipment at fixed intervals of time or operating hours. Continuous vibration monitoring is the process of continuous 24 hr/day surveillance of the vibration of equipment. The monitored data can either be continuously recorded or monitored with respect to criteria and an alarm sounded if the criteria are exceeded.

4.2 Quality Considerations

Since the basic technique used to detect equipment deterioration is trend analysis, data should be taken in as consistent a manner as possible to ensure that detected changes in vibration are actually due to machine condition changes and not errors or variations of the data acquisition technique or variations in machine loading. A monitoring program that provides data accurate within ±10% imposes the restriction that only changes in amplitude in excess of 20% can reliably be used to indicate a machine condition change. Some of the more important considerations that can affect the quality of acquired data are identified below.

4.2.1 Transducer Location. Tables 2 through 6 provide recommended locations for monitoring vibration levels of various types of rotating equipment. In applying these recommendations, each machine should be reviewed for such items as critical speed, mode shapes, seal, or special component protection (i.e., submerged transducers in vertical pumps). These locations and noted directions provide for shaft measurements near the bearings and bearing measurements on a line of action through the shaft centerline. The locations of these measurements should be clearly marked and identified to ensure repeatability of location during successive measurements.

If the mounting is external to equipment components, measurements can be influenced by vibrations transmitted to the equipment housing from the surrounding environment (e.g., piping, foundation, adjacent machinery). Therefore, mounting location should be carefully selected so measurements will accurately reflect only vibration of the machine itself, with minimal outside influences.

Table 2 Transducer Location Guidelines — Turbines

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Shaft at each bearing	Horizontal	. . .	X	. . .	X [Note (1)]	Noncontacting probe	Relative displacement
	Vertical	. . .	X	. . .	X [Note (1)]	Noncontacting probe	Relative displacement
	Vertical	X	. . .	X	. . .	Shaft rider or combination	Absolute displacement
Shaft axial position	. . .	. . .	. . .	X	X	Noncontacting probe	Relative displacement
Bearing cap	Horizontal	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity
	Vertical	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity
	Axial	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity

NOTES:
(1) Transducer should be installed at 45 deg on either side of the vertical centerline in plane of rotation.
(2) Useful for additional informational purposes.

Table 3 Transducer Location Guidelines — Equipment With Antifriction Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Each bearing housing	Horizontal	X [Note (1)]	X	X [Note (1)]	X [Note (1)]	Velocity or accelerometer	Velocity or accelerometer [Note (2)]
	Vertical	. . .	X	. . .	. . .	Velocity or accelerometer	Velocity or accelerometer [Note (2)]
	Axial	. . .	X	. . .	. . .	Velocity or accelerometer	Velocity or accelerometer [Note (2)]

NOTES:
(1) Should be horizontal or vertical, whichever is higher. Typically, horizontal is higher than vertical.
(2) Acceleration measurements (g's) tend to give better sensitivity when the failure model is characterized by high-frequency vibration.

Table 4 Transducer Location Guidelines — Horizontal Pumps — Fluid Film Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Each bearing housing	Horizontal	X	X	X [Note (1)]	X [Note (1)]	Accelerometer or velocity	Velocity or displacement
	Vertical	. . .	X	. . .	. . .	Accelerometer or velocity	Velocity or displacement
	Axial	. . .	X	. . .	. . .	Accelerometer or velocity	Velocity or displacement
Shaft at bearing	Axial	. . .	. . .	X	X [Note (2)]	Noncontact probe	Displacement
Pump shaft	Vertical	X	X	X	X	Noncontact probe or shaft rider with accelerometer or velocity	Displacement
	Horizontal	. . .	X	. . .	X	Noncontact probe or shaft rider with accelerometer or velocity	Displacement

NOTES:
(1) Direction of highest vibration.
(2) Normally used on large pumps (reactor feed, recirculating pump, etc.).

Table 5 Transducer Location Guidelines — Motor-Driven Vertical Pumps — Fluid Film Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Top motor bearing	Vertical	X	X	X	X	Velocity or accelerometer	Displacement or velocity
	Horizontal H_1 [Note (1)]	X	X	X	X	Velocity or accelerometer	Displacement or velocity
	Horizontal H_2 [Note (2)]	. . .	X	. . .	X	Velocity or accelerometer	Displacement or velocity
Lower motor bearing	Vertical	. . .	X	. . .	. . .	Velocity or accelerometer	Displacement or velocity
	Horizontal H_3 [Note (3)]	. . .	X	. . .	X	Velocity or accelerometer	Displacement or velocity
	Horizontal H_4 [Note (3)]	. . .	X	. . .	. . .	Velocity or accelerometer	Displacement or velocity
Pump shaft	Horizontal H_5 [Note (4)]	X	X	X	X	Noncontact probe or shaft rider with accelerometer or velocity [Note (5)]	Displacement
	Horizontal H_6 [Note (6)]	. . .	X	. . .	. . .	Noncontact probe or shaft rider with accelerometer or velocity [Note (5)]	Displacement

NOTES:
(1) H_1 is in the direction of maximum amplitude (if practical).
(2) H_2 is perpendicular to H_1.
(3) H_3 and H_4 are in the same direction as H_1 and H_2, respectively.
(4) Pump shaft at casing/seal penetration, H_5, direction of highest amplitude.
(5) Noncontact probe is for continuous monitoring; shaft rider is for periodic monitoring.
(6) Pump shaft at casing/seal penetration, H_6, perpendicular to H_5.

Table 6 Transducer Location Guidelines — Electric Motors

Location	Direction	Periodic Minimum	Periodic Recommended	Continuous Recommended	Transducer Type	Evaluation Parameters
Bearing cap	Horizontal	X [Note (1)]	X	X [Note (1)]	Velocity or accelerometer	Displacement or velocity
	Vertical	. . .	X	. . .	Velocity or accelerometer	Displacement or velocity
	Axial	. . .	X	. . .	Velocity or accelerometer	Displacement or velocity

NOTE:
(1) Should be horizontal or vertical, whichever is highest. Typically horizontal is higher than vertical.

4.2.2 Transducer Attachment. The method used to attach the transducer to the rotating equipment is one of the most important considerations for repeatable data. All transducer brackets and mount locations must be rigid for the frequency range of interest. Permanently attached transducers are preferred because they are not movable and any attachment errors are the same for all measurements. Other attachment procedures, such as handheld, magnetic base, adhesive mounting, etc., can have some amount of looseness. Looseness will reduce the high-frequency response and improperly transmit high- and low-frequency vibration to the transducer; it can create apparent vibration in the signal not present on the equipment.

4.2.3 Transducer Selection. The choice of transducer must be made considering a large number of factors depending on the individual equipment being monitored and the type of measurement desired. Tables B-1 through B-5 of Nonmandatory Appendix B of this Part list advantages and disadvantages of the five principal transducer types and their use. The transducer and data processing equipment should have a flat response over the frequency range of interest.

Displacement transducers should be used where relative displacements are critical such as when evaluating shaft vibration relative to bearing or seal clearance. Velocity probes should be used for low- or medium-frequency measurements such as shaft vibration via shaft riders and casing measurements. Accelerometers should be used for wideband frequency measurements, in particular for high-frequency measurements such as impacts.

4.2.4 Data Processing Equipment. Data processing equipment should be selected that minimizes distortion of the input signals and extracts the meaningful parameters in a consistent, repeatable manner. Parameters to be considered in selecting processing equipment are as follows:

(a) Frequency response of the processing equipment should be flat over the frequency range of interest.

(b) Processing equipment should not modify the data by such things as filter ringing, inadequate data, sample size, or loss of transient data.

(c) Parameters (displacement, velocity, acceleration) should be selected to include the frequency ranges of importance. For example, acceleration and, to a lesser degree, velocity measurements tend to emphasize high frequency.

4.2.5 Parameters Measured. The selection of the parameter being measured is important for a proper analysis of the vibratory response of rotating equipment. For example,

(a) displacement measurements tend to emphasize response from low-frequency components. Such measurements should be used to determine low multiples of running speed components and subsynchronous vibration.

(b) velocity measurements can be advantageous for use over a wide frequency range (up to 1 kHz using velocity transducers or up to 5 kHz using accelerometers). They are able to reflect a wide range of problems and are generally accepted as the best measure of overall vibration severity, particularly when many frequency components are present. Since equipment failure is affected by both amplitude and number of cycles, velocity is a convenient measurement parameter.

(c) acceleration measurements tend to emphasize the higher frequency components of machine vibration. Hence, acceleration measurements may be most suitable for detecting high-frequency machine problems such as gear meshing and roller bearing defects.

4.2.6 Meter Reading Techniques. The general techniques for reading an instrument should be well understood by individuals using the equipment. Analog meters should be read only in the upper two-thirds of the meter range. Digital meters can be read throughout their entire range. The procedure for reading swings in meter indications should be defined. Root mean square (rms) amplitudes are useful for varying amplitudes but tend to mask impact signals. Conversely, a system that has fast enough response to measure impact signals may be inconsistently read by multiple operators. Where multiple operators are used to implement the monitoring program, use of an averaging type meter is recommended. The relationship between the normal rms signal value and peak value should be considered when comparing measurements to acceptance criteria.

4.2.7 Data Logging Techniques. Vibration data should be logged on a data sheet such as that in Fig. 1. The information on the data sheet should include an identification of the equipment to be monitored, a schematic figure of the equipment showing the measurement locations, the vibration analyzer used, and a listing of the data to be obtained during each surveillance (periodic or continuous). Also to be included are the operating parameters to be recorded. This particular data sheet is set up to record data for many surveillances.

Data should be logged in such a manner that inconsistent data can be identified as it is being taken. The data sheet should contain the previous data for immediate in-field comparison to new data. This will facilitate the taking and review of repeat measurements. The data sheet should also contain the vibration limits or other acceptance criteria to be used with each piece of equipment. When a computer system is employed to obtain data, the same data should be recorded.

5 ESTABLISHING THE BASELINE

5.1 Baseline Data

Baseline vibration data are those data obtained when the equipment is known to be operating acceptably. Subsequent measurements are compared to the baseline values to detect changes in the level of vibration of the rotating equipment. Baseline data must accurately define the acceptable vibration condition of the equipment under normal operating conditions. Baseline vibration data are established for new and overhauled equipment or equipment whose previous baseline data may have been affected by maintenance. If the equipment is normally operated in more than one mode (e.g., different speeds or loads), baseline data should be established for each mode.

Baseline vibration data should be obtained for all vibration parameters that are commonly used to define the equipment's vibration condition. The more comprehensive the initial definition of baseline, the greater the likelihood of properly detecting, diagnosing, and tracking the deterioration of the rotating equipment. The parameters commonly used to define a vibration baseline include the following:

(a) overall unfiltered amplitude (displacement, velocity, or acceleration)
(b) filtered running speed amplitude (displacement)
(c) filtered running speed phase
(d) frequency spectrum of vibration signals
(e) coastdown frequency response
(f) startup frequency response
(g) shaft orbit

5.1.1 The extent of the baseline signature determination should depend on such items as the following:

(a) importance of rotating equipment
(b) previous history of equipment
(c) analysis equipment available
(d) capabilities of personnel

The locations at which data are obtained need not and should not be limited to those locations that are to be periodically monitored as recommended in section 4. It is recommended that the baseline be a comprehensive vibration analysis encompassing many more measurement points and directions than could reasonably be collected during periodic or continuous monitoring. After either continuous or periodic monitoring has established that a change in vibration level is taking place, a repeat of the methodology used for baseline analysis can help define the cause of the vibration change.

Operating data should also be taken to document the conditions under which the vibration was measured.

5.2 Methods to Establish Baseline

For new and overhauled equipment, there is often a wear-in period as illustrated in Fig. 2 and it is not uncommon to see a change in vibration level during the first few days or weeks of operation. Time should be allotted for wear-in before baselining. For equipment that has been operating for a significant period and monitored for the first time, machine vibration can exist anywhere on the vibration trend curve. Data taken for baseline should be taken in Zone 2 of Fig. 2. Periodic monitoring will establish the applicable zone. Figure 2 is an example vibration trend curve. The shape of the curve will tend to vary for different rotating equipment.

After monitoring has established that the equipment has reached an acceptable condition, full baseline data should be taken. Monitoring should then continue as originally planned. The initial data and baseline data should be compared to specified criteria to determine the acceptability of the equipment vibration levels. These data are the basis on which future equipment problems will be detected and diagnosed. They must be stored in a manner that is easily retrievable and secure.

6 ESTABLISHING VIBRATION LIMITS

6.1 Purpose

The purpose of this paragraph is to establish the criteria for determining maintenance schedules for rotating equipment when guidance based on vibration monitoring is not provided by the manufacturer or needs to be enhanced. The criteria provides for the use of data

Fig. 1 An Example of a Vibration Data Sheet

Sample Machine Diagram

Plant ______________________________

Unit ______________________________

Equipment (name/number) ______________________________

Driver ______________ Manufacturer ______________

rpm __________ hp __________ Amps __________

Coupling Type ______________ Manufacturer ______________

Driven ______________ Manufacturer ______________

rpm ______________ Vibration Equipment Used ______________

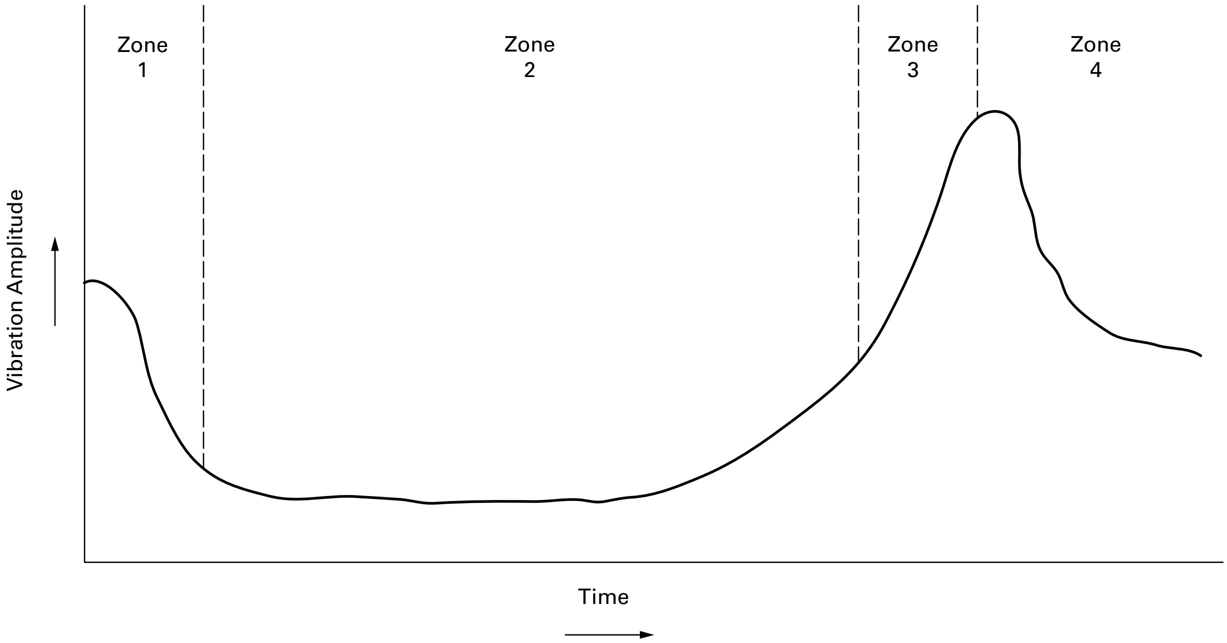
Date

	P	Limits											
Bearing	O S	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
Amps													
Suction, psig													
Discharge, psig													
ΔP													
Temperature, °F													
Load, MW													
Readings by													

Pickup point Plain bearing Coupling Antifriction bearing

Comments ______________________________

Fig. 2 An Example of a Vibration Trend Curve



Zone 1: new machine roughness (wear-in period)
Zone 2: useful machine life
Zone 3: corrective action should be taken
Zone 4: component failure with either continuing increase or partial reduction of vibration

acquired during either periodic or continuous monitoring. The interval of monitoring or data review will vary depending on the level of vibration observed, and the rate at which the vibration level is changing. The current condition of the equipment should be used to specify the frequency of periodic monitoring and minimum period for review of data obtained by continuous monitoring of equipment.

A primary consideration in developing the criteria is consistency with Division 1, Subsection ISTB, which specifies three ranges of vibration: acceptable range, alert range, and required action range. The criteria are such that maintenance occurs prior to reaching the lower limit of the required action range.

6.2 Parameters

Standard practice is to process displacement in mils peak-to-peak, velocity in in./sec zero-to-peak, and acceleration in *g*'s zero-to-peak, or rms. The method of processing peak-to-peak and zero-to-peak varies with the type of meter detector used and should be considered to ensure consistency of data.

6.3 Criteria

The vibration level for rotating equipment is divided into three ranges, an acceptable range, an alert range, and a required action range. Each of these ranges is defined by a vibration limit.

The recommended procedure for establishing limits for each of these ranges is as follows:

(a) Review the manufacturer's vibration criteria if available.

(b) If the manufacturer's vibration criteria are not available (pumps only) and Division 1, Subsection ISTB applies, then Table ISTB 5.2-2 should be used to establish the limits for each of the ranges.

(c) When limits for each of the ranges cannot be established using either of the above methods, the technique described in section 5 should be used to determine the baseline vibration level. Structural analysis or engineering judgment should be applied in determining the upper limits for the acceptable range and the alert range. A factor of two increase over baseline vibration for the upper limit of the acceptable range and a factor of four increase over baseline vibration for the upper limit of the alert range are recommended maximum values.

The action required or recommended when equipment is operating in each of these zones depends on the rate at which the vibration level is changing. These actions are described below. Figures 3 and 4 depict two examples of results from a biweekly surveillance.

Fig. 3 Vibration Level Trend Plot of Condition One
(For Defined Vibration Limits From Manufacturer's Data or Equivalent)

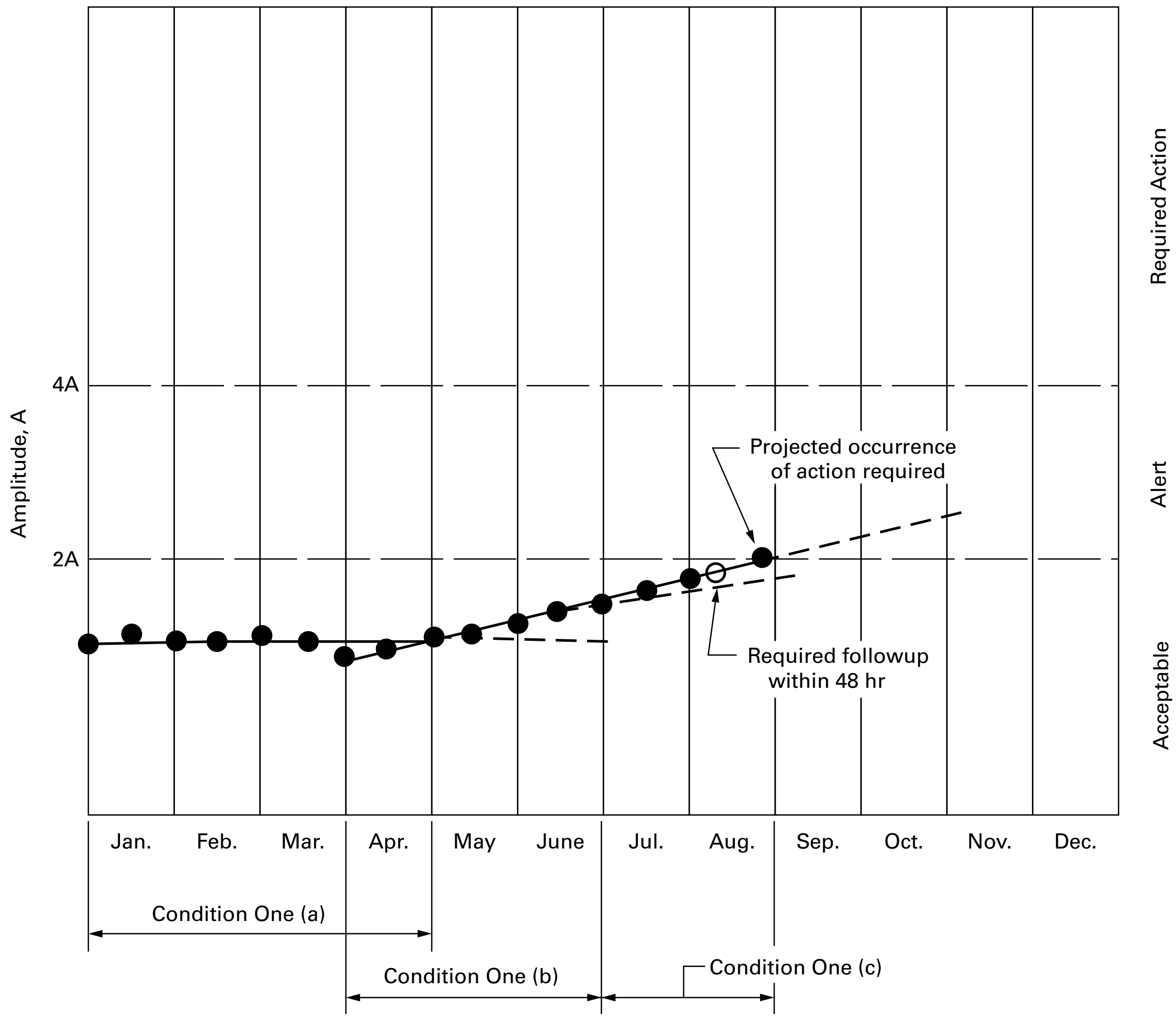
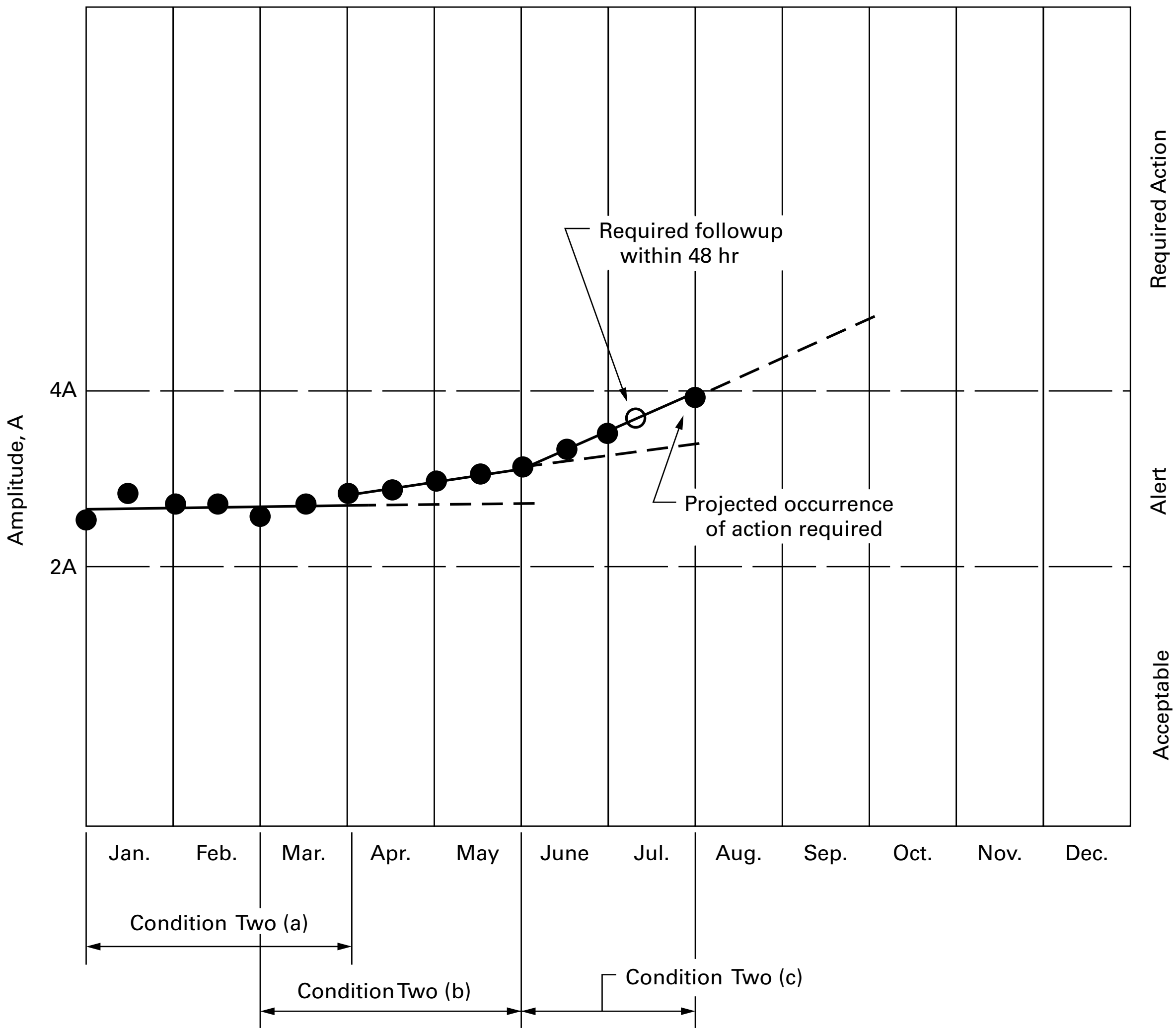


Fig. 4 Vibration Level Trend Plot of Condition Two
(For Defined Vibration Limits From Manufacturer's Data or Equivalent)



6.3.1 Condition One. Equipment vibration level is in the acceptable range according to the following:

(a) If there is no increase in level from previous data, then no action is required [Condition One (a)].

(b) If vibration is increasing, confirm rate within 48 hr.

(1) If the rate of increase is linear and does not project to exceed upper limit of normal range before next scheduled surveillance, then no action is required [Condition One (b)].

(2) If the rate of increase is linear and projects to exceed upper limit of normal range before the next scheduled surveillance, schedule more frequent monitoring before upper limit will be reached [Condition One (c)].

(3) If the rate of increase is nonlinear, confirm the rate within 48 hr, schedule more frequent monitoring, and implement a diagnostics program.

(c) A decreasing trend in vibration amplitude is sometimes a symptom of equipment problems and diagnostics may be warranted.

6.3.2 Condition Two. Current vibration level is in the alert zone according to the following:

(a) If there is no increase in level from previous data, continue to monitor biweekly [Condition Two (a)].

(b) If the level is increasing linearly but does not project to exceed the action level prior to the next scheduled review of the vibration level or scheduled maintenance, confirm the rate of increase within 48 hr and implement a diagnostics program [Condition Two (b)].

(c) If the level is increasing at a linear rate that projects to exceed the action level before the next scheduled surveillance or if the rate of increase is nonlinear, confirm the rate with more frequent readings and reschedule maintenance as required. Increase the frequency of monitoring to ensure that at least three data points are collected prior to rescheduled maintenance. A diagnostics program is recommended to define the problem and identify maintenance required [Condition Two (c)].

If a decrease in vibration level is observed, the biweekly monitoring rate should continue; detailed diagnosis is recommended.

7 DATA ACQUISITION

Instrumentation selection and use are key ingredients in data acquisition. The selection of instrumentation is primarily governed by the type of measurement to be taken (i.e., displacement, velocity, or acceleration), the type of equipment being monitored, the range of frequencies of interest and the environment in which the instruments must operate. Tables 2 through 6 recommend the type of measurement that should be used depending on the type of equipment being monitored. Nonmandatory Appendix A of this Part addresses instrumentation installation and calibration, pretest conditions, measuring and recording information, special considerations, and personnel.

8 HARDWARE

Selection of the proper transducer/measurement/monitoring combination is important for equipment protection and for obtaining an accurate measurement. Nonmandatory Appendix B of this Part provides guidance in selecting transducers and analysis equipment. Additional information can be found in the standards and publications referenced in section 3.

9 DIAGNOSTICS

9.1 Purpose

This paragraph is intended as a guide to identify possible causes of equipment vibration. It is recommended that the user refer to the references listed in section 3 for more details on causes of vibration.

Section 4 suggests methods of formulating or collecting data based on what is suspected to be the cause of the problems and is not intended to be a recommendation of any particular data analysis equipment. In most cases, knowing frequency content and amplitude is sufficient for problem identification, with phase data being desirable for complicated vibration problems. It is recommended that individuals involved in diagnostics have, as a minimum, formal training in rotating equipment vibration analysis or the assistance of trained personnel to be most effective.

9.2 Troubleshooting

Table 7 lists some potential causes of machinery vibration and what is typically observed in terms of frequency content and direction of the vibration, along with appropriate remarks. There are several charts of this type available in the references listed in section 3, which the user may find useful. These charts are no substitute for experience and engineering judgment.

Table 7 Vibration Troubleshooting Chart

	Frequency of Vibration (Hz = rpm/60)	Direction	Remarks
Rotating members out of balance	1 × rpm	Radial	The most common cause of excess vibration in equipment
Misalignment and bent shaft	Usually 1 × rpm; often 2 × rpm; sometimes 3 × and 4 × rpm	Radial and axial	The second most common fault
Rubs	1 × rpm and possible higher multiples	Radial	A common cause of excess equipment vibration
Damaged rolling element bearings (ball, roller, etc.)	Impact rates for the individual bearing components; also, vibrations at very high frequencies (20–60 kHz)	Radial	Uneven vibration levels, often with shocks
Journal bearings loose in housings	Subharmonics of shaft rpm; exactly $\frac{1}{2}$ or $\frac{1}{3}$ rpm	Primarily radial	Looseness may only develop at operating speed and temperature (e.g., turbomachines)
Oil film whirl or whip in journal bearings	Less than $\frac{1}{2}$ shaft speed	Primarily radial forward whirl	Vertical and lightly loaded horizontal equipment
Hysteresis whirl	Shaft critical speed	Primarily radial	Vibrations excited when passing through critical shaft speed are maintained at higher shaft speeds; can sometimes be cured by checking tightness of rotor components
Damaged or worn gears	Tooth-meshing frequencies (shaft rpm × number of teeth) and harmonics	Radial and axial	Sidebands around tooth-meshing frequencies indicate modulation (e.g., eccentricity) at frequency corresponding to sideband spacings; normally detectable only with very narrow band analysis
Mechanical looseness	2 × rpm, or 1 × rpm if loose part becomes rotating unbalanced	Radial and axial	Also sub- and interharmonics and for loose journal bearings
Faulty belt drive	1 ×, 2 ×, 3 ×, and 4 × rpm of belt, usually 2 ×	Radial	. . .
Unbalanced reciprocating forces and couples	1 × rpm and/or multiples for higher order unbalance	Primarily radial	. . .
Electrically induced vibrations	1 × rpm or 1 × or 2 × synchronous frequency	Radial and axial	Should disappear when power is turned off
Shaft position changes	All	Radial and axial	Indicates bearing load changes, external forces, and process upsets

Part 14, Nonmandatory Appendix A Instrumentation Selection and Use

A-1 INSTALLATION OF TRANSDUCERS

A-1.1 Mounting Techniques

Monitoring may be accomplished using either permanently or temporarily mounted transducers. Permanently mounted transducers using manufacturer's specifications are recommended. When using temporarily mounted transducers, care should be taken to follow the special considerations within this Part. The principal effects of the different mounting techniques are to limit the useful frequency range of the transducer, introduce erroneous signals, and reduce reproducibility of the data. Most transducers will amplify signals near the mounted resonance of the transducer.

A-1.1.1 Stud Mounting. Stud mounting is a reliable technique for fastening transducers directly to a surface for measurement. The stud may be fastened to a surface by drilling and tapping or by welding or brazing. Care should be taken to mount the transducer flatly without overhang or surface discontinuity. Suggested mounting techniques supplied by the transducer manufacturer generally provide the desired accuracy and prevent possibilities for transducer damage. Isolation pads are available for electrical insulation when necessary.

A-1.1.2 Handheld Measurement. For most periodic vibration checks, a handheld transducer without extension probe is generally satisfactory. The transducer should be held against a flat surface with its entire face in contact with the surface. Care should be taken to apply only enough pressure to prevent chattering of the transducer on the surface, which can produce a false high-frequency vibration indication. Extension probes should only be used for convenience in reaching out-of-the-way measurement points. Generally, the shorter the probe the better, especially when measuring higher vibration frequencies.

A-1.1.3 Magnetic Transducer Holders. The magnetic holder should provide acceptable results when applied to a reasonably flat, smooth, clean, unpainted surface. Paint, grease, and dirt reduce magnet holding power, thus reducing maximum usable frequency range and introducing the possibility of chatter or rocking.

A-1.1.4 Bonded Mounting. When a more permanent attachment cannot be used, transducers can be installed on structures using adhesives such as epoxy. The adhesive must be specified for the environment in which it is to operate (e.g., temperature or radiation) and must not be detrimental to the surface of the equipment. Preferably, this should be considered a short-term installation with the transducer eventually being more permanently secured with stud or bolt mounting.

A-1.1.5 Quick-Release Mounting. Quick-release mounting provides a positive locking mechanism for periodic monitoring purposes. The usable frequency range and repeatability are also improved when compared to handheld or magnetic holder methods.

A-1.2 Types of Measurement

A-1.2.1 Bearing Housing Absolute Measurement. Bearing housing absolute measurement can be accomplished using either velocity or accelerometer pickups and is defined as the vibratory motion of the housing in free space.

A-1.2.2 Shaft Absolute Measurement. Shaft absolute measurement is defined as the vibratory motion of the shaft in free space and can be accomplished using the following measurement techniques:

(a) combination shaft probe (see Nonmandatory Appendix B of this Part)

(b) shaft riders (see Nonmandatory Appendix B of this Part)

(c) shaft stick (see Nonmandatory Appendix B of this Part)

A-1.2.3 Shaft Relative Measurement. Measurement of shaft relative vibration can be accomplished using noncontacting probes mounted to the machine support structure. Ideally, the support member should be the bearing, bearing housing, or a direct bearing support element. If there is not looseness between the bearing and bearing housing, this yields a measurement of shaft vibration relative to the bearing clearance. Typically, probes are installed adjacent to the bearing, but installations through the bearing itself are also possible.

Care should be taken to ensure that the probe senses a nonplated, journal-quality shaft surface, free from mechanical and electrical runout in excess of 0.25 mils. If runout criteria cannot be met, this should be compensated for electronically. Runout should be determined on a fully heat-soaked machine. When mounting brackets are required to fix the probe to the machine support structure, the bracket and probe resonant frequency should be well above the range of expected machine vibration frequencies.

A-2 CALIBRATION

Instrumentation used for periodic monitoring should be calibrated in accordance with the Owner's quality assurance program. Recommended calibration intervals are prescribed below.

Equipment	Interval
Accelerometers, noncontacting probes	1 yr
Velocity probes	6 months
Meters and instruments	1 yr

New or repaired instruments should be calibrated prior to use. A system of records should be established to identify each instrument and calibration date, and each instrument may contain an attached tag or sticker identifying the date of last calibration and expiration date.

A-3 PRETEST CONDITIONS

Equipment monitoring should take place with equipment operating conditions identical to those for which baseline data were accumulated. Vibration levels are generally responsive to change in equipment operating conditions. These conditions include pump flow and fluid temperature, motor amperage, bearing and lubricating oil temperature, and rotating speed. Efforts should be made to match machinery operating conditions each time data are gathered.

A-4 MEASURING AND RECORDING INFORMATION

Periodic monitoring data may be gathered using permanently installed or portable instrumentation. Data must be obtained at previously established measurement points on each piece of rotating equipment. For trending, data sheets should be used for equipment identification, discussion of special conditions or machine setup, and tabulation of data. A typical data sheet is shown in Fig. 1 of this Part. Alternately, microprocessing or storage devices capable of providing the same results are also acceptable.

A-5 SPECIAL CONSIDERATIONS

A-5.1 Natural Frequency

The natural frequency of the transducer or transducer–probe combination should be determined and accounted for in the analysis of data.

A-5.2 Magnetic/Electrical Interference

Alternating magnetic fields, inherent with AC monitors or generators, can interfere with the output of some vibration transducers. This can be evaluated by suspending the transducer in the area where the data are normally taken. No significant signal should be measured when the machine is running. If magnetic/electrical interference exists, shielding should be considered where recommended by the manufacturer. Otherwise, an alternate measurement system should be tried.

Care should also be taken to ensure that instrumentation systems do not cause ground loops emitting 60 Hz signals.

A-5.3 Environment

Care should be taken to select vibration instruments suitable for use in harsh or hazardous environments. Harsh or hazardous environments include, but are not limited to, those areas where instrument reliability could suffer or be lost due to heat, dust, moisture, corrosives, or radiation. In addition, operator safety should not be jeopardized by toxic gases, radiation, or vibration instruments igniting combustibles.

A-6 PERSONNEL

Personnel used for gathering of periodic data should be trained and knowledgeable in the use of vibration instrumentation as applicable to specific policies, procedures, and quality assurance requirements.

Part 14, Nonmandatory Appendix B Transducers and Analysis Equipment

B-1 TRANSDUCERS

(a) There are three basic parameters (displacement, velocity, and acceleration) commonly measured for equipment vibration applications. The selection of the transducer type used to make these measurements is governed by the following:

(1) type of monitoring program being conducted
  (-a) periodic
  (-b) continuous
(2) type of bearing
  (-a) sleeve
  (-b) rolling element/antifriction
(3) bearing stiffness
(4) transmissibility
(5) foundation/pedestal flexibility

(b) Periodic monitoring programs usually require portable instrumentation to measure casing or bearing cap vibrations. Care needs to be taken to ensure that readings are taken on a structural part of the machine such as the equipment frame or bearing cap.

(c) Continuous monitoring transducers are permanently mounted to the machines. Tables 2 through 6 of this Part provide the guidelines to be considered when selecting which type of transducer to use. Care should be taken to ensure that the transducer and its installation do not significantly alter machine natural frequency.

(d) Considerations in selecting a transducer for a particular job include the following:

(1) sensitivity mV/g
(2) frequency range
(3) size
(4) temperature range
(5) amplitude range
(6) radiation
(7) mounting method
(8) accuracy

(e) The advantages and disadvantages of each transducer type are given in Tables B-1 through B-5.

B-1.1 Noncontact Transducer

A common displacement transducer for rotating equipment monitoring is the noncontacting eddy probe system. This is an electrical device that measures the relative motion between the probe mount (bearing) and target material (shaft). These solid state devices have no moving parts and produce an output signal proportional to component position (DC level) or change in position (AC signal) within a bearing for monitoring or diagnostics purposes.

Standard noncontacting probes that monitor equipment vibration normally have a linear range from 10 mils to 90 mils with either a 100 mV/mil or 200 mV/mil sensitivity and a 0 kHz to 10 kHz frequency range. The shaft material absorbs energy from the magnetic field radiating from the probe. The closer the shaft gets to the probe, the more energy that is removed from the magnetic field, resulting in a reduced output from the oscillator/demodulator and producing a varying voltage proportional to the changing gap between the shaft and the probe. This signal corresponds to the relative motion between the shaft and the bearing. Due to the different electrical properties of different materials, the probes must be calibrated for the particular material being observed.

Runout can cause errors in the vibration signal from a noncontacting probe. Mechanical runout caused by misalignment, eccentricities of the shaft, or other surface irregularities can be removed by using established techniques.

Electrical runout caused by factors such as localized carbon or chrome in the shaft material, forging methods, or shaft spraying requires machining of the shaft surface or electronic removal of the runout signal.

B-1.2 Velocity Transducers

Velocity transducers are normally electromechanical devices that use either a reference coil and movable magnet or reference magnet and movable coil to produce an output signal proportional to the velocity of a vibrating component. Mechanical velocity transducers are self-generating devices that develop signals, usable for rotating equipment monitoring or diagnostics. The transducer uses a spring-mass damper system to produce a very low resonance frequency.

This transducer is an electromechanical device that is subject to wear, sticking, corrosion, and stray electrical fields from motors or generators. The standard transducer's damping medium normally limits usable temperatures to about 250°F with output sensitivities from 100 mV/in./sec to 1,000 mV/in./sec. Standard usable frequency range is from 10 Hz to 1,000 Hz.

An alternative method of developing a velocity signal is to perform integration on a piezoelectric accelerometer signal. This extends the usable frequency range of the velocity transducer.

Table B-1 Noncontacting Displacement Probes — Probe Advantages Versus Disadvantages

Advantages	Disadvantages
1. Measures directly the dynamic motion (relative to point of probe attachment) of the shaft, which is the source of vibration for the most common (frequently occurring) machine malfunctions, such as imbalance, misalignment, rubs, bearing instability, etc.	1. Runout (electrical and mechanical); dependent upon homogeneous shaft material, high-quality shaft surface finish, free from scratches, rust, corrosion, chrome plating, etc., and localized (spot) magnetic fields
2. Measures average rotor position (relative to bearing or housing attachment point) within the bearing clearance, an important indicator of steady-state undirectional preloads on the rotor, such as from misalignment, fluidic, or aerodynamic influences, etc.	2. Sensitive to some shaft materials (metallurgical content); may require special calibration to specific material
3. Ease of calibration; only static calibration required using spindle micrometer and digital voltmeter	3. Requires external DC power source
4. Same type of transducer can also be used for axial thrust position, rotor eccentricity (bow), rotor speed, phase angle (keyphasor reference), and differential expansion measurements	4. Can be difficult to install on some machine (bearing) designs
5. Measures directly in engineering units of displacement	5. Usually difficult to install quickly on a temporary basis; probes should be permanently installed even for periodic measurements
6. Good signal-to-noise ratio; high-level, low-impedance output can be separated from monitor by over 1,000 ft (300 m)	
7. Broad frequency response, from 0 Hz (DC or static position) to 10 kHz	
8. Solid-state for extended reliability (no moving parts)	
9. Modular system design that spreads the cost to cover replaceable components	

Table B-2 Velocity Transducers — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Ease of installation (mounted to machine externals, e.g., bearing housing)	1. Provides limited information about shaft dynamic motion, requires that the machine have low mechanical impedance
2. Strong signal in the midfrequency ranges (15 Hz to 1 kHz)	2. Mechanical Design (spring/mass/damper) a. Degrades somewhat over a period of time under normal use b. Cross axis sensitivity problems at high temperatures c. Rather large and heavy d. Not extremely rugged
3. Seismic type transducers are self-generating, with no external power source required; accelerometer types are not self-generating	3. Unit construction (any transducer fault requires replacement of complete transducer assembly)
4. Can measure shaft absolute (relative to free space) vibration when mounted to a rider (permanent installations) or “fishtail” (temporary installations)	4. Difficult calibration; requires removal from the machine and use of a shaker table
5. Adequate frequency response for overall evaluation of machines in the midspeed range	5. Amplitude and phase errors introduced at low frequencies
6. Can be temporarily installed with reasonable success using a magnetic base	
7. Models are available for moderately high temperature	
8. Velocity is relatively easy to integrate to displacement	

Table B-3 Accelerometers — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Ease of installation (mounted to machine externals, e.g., bearing housing) in case-mounted applications (however, refer to item 3 under "disadvantages")	1. Provides only limited information about shaft dynamic motion (for overall evaluation of machine vibration); requires that the machine have low mechanical impedance
2. Very useful for high-frequency measurements, above 2 kHz	2. Susceptible to noise resulting from method of attachment or poor contact to machine housing; requires deliberate effort to achieve effective installation. Frequency response limited when used with a temporary mounting, even more so when hand held
3. Effectively no moving parts; good reliability	3. Unit construction means that any transducer fault requires replacement of complete transducer assembly
4. Models are available for high-temperature applications, beyond the range of other transducers	4. Difficult calibration; requires removal from the machine and use of a shaker table
5. Relatively light weight	5. Difficult to use for some low-speed machines and other low-frequency applications, since low-acceleration levels produce signals which are typically not far above noise floor (poor signal to noise ratio)
6. Broad frequency response	6. Double integration to displacement for overall evaluation of machinery vibration is susceptible to electrical noise and electronic integration problems, particularly in the low-frequency region
	7. Sometimes requires filtering in the monitor, and the filters must be individually determined for each machine case
	8. Somewhat sensitive to damage (requiring replacement) due to harsh impact (dropping on concrete, etc.), particularly in the nonsensitive axis

Table B-4 Combination Probe Attached to Bearing Housing — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Incorporates all the advantages of the noncontacting probe	1. Phase and amplitude errors at low frequencies (less than 1200 cpm) in absolute measurements which must be corrected by electronic or manual (graphic) means for velocity transducers
2. Provides four pieces of information allowing connection to a wide variety of diagnostic instruments for machine problem investigation: a. shaft absolute motion b. shaft relative motion c. bearing housing motion d. average shaft position in bearing clearance	2. Mechanical design of seismic element-performance will deteriorate over a period of time in normal use
3. Broad frequency response: 4.5 Hz to 1 kHz for absolute measurements, DC to 10 kHz for relative measurements	3. Disadvantages listed in Table B-1 also apply
4. Provides measurement of shaft motion relative to bearing and bearing motion relative to free space; and, therefore, indicates mechanical impedance of the system-actual impedance from shaft through oil film, through the bearing, the bearing support, and out to the location of the seismic transducer	4. Disadvantages listed in Tables B-2 and B-3 apply depending upon transducer used

Table B-5 Shaft Rider — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Provides shaft absolute dynamic motion directly	1. Contacting: wear can occur between tip and shaft
2. Self-generating transducer, e.g., does not require power supply	2. Limited frequency response: 10 to 120 Hz typically; limited shaft slow roll (bow or eccentricity) measurement
	3. Must be located in lubricated area
	4. May, under extreme cases, damage shaft or bearing
	5. Rider may "hydroplane" on oil film
	6. Friction in shaft rider guide can cause errors in output because rider may not exactly follow shaft motion
	7. Moving parts: seismic element, slider, spring, rider tip on shaft; performance will deteriorate in time under normal use
	8. Slip bounce, squeal, or chatter can occur if proper lubrication and shaft surface finish are not maintained
	9. Errors due to mechanical runout
	10. Phase and amplitude errors at low frequencies (caused by the seismic element) and at higher frequencies (caused by the mechanical riding system)

B-1.3 Acceleration Transducer (Accelerometer)

An accelerometer is a solid state device that normally uses a piezoelectric crystal to develop an output signal proportional to the acceleration of a vibrating component. Accelerometers for machinery applications normally use internal amplifiers and external power to develop a signal usable for machinery monitoring or diagnostics.

Because of their small mass, accelerometers have a wide frequency range (2 Hz to 5,000 Hz) and large dynamic range (90 dB). The accelerometer is solid state, has low mechanical wear, and requires very little calibration with age. However, the internal electronics limit standard accelerometer usage to temperatures below 250°F. For applications above 250°F, accelerometers with external electronics and power supplies are also available.

Typical sensitivities range from 10 mV/g to 100 mV/g (1g = 386.1 in./sec/sec) and provide strong high-frequency signals.

B-1.4 Combination Transducers

A combination transducer consists of a noncontacting displacement transducer mounted to the bearing housing (see para. B-1.3) to measure shaft-relative vibration and a seismic probe to measure the bearing housing vibration. The signal from the seismic probe is electronically integrated to displacement and combined with the noncontacting transducer output to provide a measurement of shaft absolute vibration (relative to free space) for monitoring or diagnostics. Combining of the two signals is usually accomplished by the readout/monitoring equipment.

Either an accelerometer or a velocity transducer can be used to measure the bearing housing vibration. Electronics are required to compensate for the phase lags associated with velocity transducers (see para. B-1.2).

When using this technique, caution should be exercised to ensure that the seismic probe actually measures the same motion as the noncontact probe support. Erroneous signals have been developed by not installing the seismic probe directly in line and in the same plane as the eddy probe. Erroneous signals have also been generated by not installing the seismic probe rigidly to the noncontact probe support.

B-1.5 Shaft Rider

The shaft rider is a mechanical spring-loaded device that physically rides on the shaft surface. A seismic transducer attached to a rod converts the rod's mechanical motion into an output signal that is proportional to the shaft absolute radial motion. The shaft rider tip is constructed of a material softer than the shaft material yet rigid enough to transmit the shaft's vibration to the seismic transducer. The surface on which the shaft rider rides must be well lubricated (to prevent chatter), smooth, and free from mechanical runout and scratches.

Since the shaft rider mechanically follows the radial shaft motion, its applications are physically limited by shaft speed, circumference, tip material, and amount of lubrication. Most shaft riders are further limited by the transducer system response to less than 200 Hz.

B-1.6 Shaft Stick

A shaft stick is a stick or paddle on which a transducer is mounted and held against a smooth, rotating part of the shaft for measuring absolute motion. Care should be taken in each instance to eliminate chattering. Consider items such as shaft smoothness and geometry, shaft speed, and such. Handheld sticks should be coated with a medium weight lubricating oil in contact with the shaft, and the stick material should be sufficiently soft to avoid shaft damage. It may be desirable to polish the shaft damage. It may be desirable to polish the shaft with emery cloth prior to taking readings. The shaft stick should ride freely on the shaft and not be jammed into position.

B-1.7 Once Per Turn Phase Angle Reference

There are usually three ways of obtaining a once per turn phase angle reference; they are as follows:

(a) a noncontacting probe observing a notch or projection located on the radial or axial shaft surface

(b) a magnetic transducer observing a notch or projection located on the radial or axial shaft surface

(c) an optical transducer observing an optical discontinuity on the radial or axial surface of the shaft

B-2 CONTINUOUS VIBRATION MONITORING INSTRUMENTS

B-2.1 Vibration Switch

A vibration switch is an integral seismic transducer and monitoring device that senses the structural vibration level of a mounting surface and provides a contact actuation when vibration exceeds a preset level.

B-2.2 Nonindicating Monitor

A nonindicating monitor accepts a vibration signal from a transducer and performs vibration detection and signal conditioning. It provides a DC voltage proportional output and contact closure where the vibration exceeds a preset level.

B-2.3 Indicating Monitor

Indicating monitors provide the same functions as nonindicating monitors plus local metering and local indication. Some self-checks are performed to ensure proper monitoring system operation.

B-2.4 Diagnostic Monitor

Diagnostic monitors use transducer analog signals as input to computer or microprocessing systems. The computer or microprocessing system uses the analog signal and provides digital data storage, trending, spectrum analysis, and such.

B-3 PERIODIC ANALYSIS INSTRUMENTATION

B-3.1 Go/No Go Meter

A go/no go meter provides a nondimensional indication of vibration severity.

B-3.2 Overall Level Meter

An overall level meter provides a dimensional value of overall unfiltered vibration amplitude.

B-3.3 Tunable Filter

A tunable filter provides indication of vibration amplitude at a selected frequency or over a frequency range. Output to a stroboscopic light can be used for phase angle measurement.

B-3.4 Oscilloscope

An oscilloscope provides time domain and orbital displays of vibration signals.

B-3.5 Fast Fourier Transform Analyzer

A Fast Fourier Transform Analyzer (FFT) is an instrument that separates a complex signal into its frequency and amplitude components in a simultaneous display.

B-3.6 Portable Integral Memory Data Acquisition and Playback Instrument

An integral memory data acquisition and playback instrument is a transportable instrument used to acquire and store vibration signals into internal memory. These signals can then be transferred to a host computer for storage and data manipulation.

B-3.7 Tape Recorders

AM or FM tape recorders are used for storing analog vibration data for subsequent analysis by the instrumentation described above.

Part 17
Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants

Superseded by Part 28 in Division 2.

Part 19
Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part provides guidance for preservice and inservice testing to assess the operational readiness of certain pneumatically and hydraulically operated valve assemblies used in light-water reactor (LWR) power plants.

The pneumatically and hydraulically operated valve assemblies covered are those required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Part recommends test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Exclusions

Valve assemblies that perform no active function within the scope defined in para. 1.1 are excluded from testing under this Part. The guidance applies to active valve assemblies; however, the guidance may be used for passive valve assemblies if the Owner elects to ensure that the valve assemblies are set properly to maintain their passive position. Self-operated pneumatic and hydraulic devices, such as air supply regulators, are excluded from the scope of this Part, except where they are included as a subpart of the valve assembly.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

baseline test: a test to collect data at specific repeatable conditions to establish a basis for comparison with subsequent inservice test data.

bench set: for operators with a spring, the pressure range over which the operator will stroke from start to its rated travel. Bench set is typically adjusted without service loads and typically either without friction loads or with minimal friction loads.

dynamic test: a test conducted with system pressure and/or flow.

expected service conditions: plant conditions at which the valve assembly is required to operate to perform its intended safety function.

hydraulic operator: a device that provides energy to open, close, or position a valve via hydraulic pressure.

inservice test: a test to determine the operational readiness of a system, structure, or component after first electrical generation by nuclear heat.

maximum available pneumatic pressure: the maximum pressure available to the actuator.

operational readiness: the ability of a component to perform its intended function(s).

performance testing: a test, or combination of tests, designed to acquire operational performance data, including baseline tests, inservice tests, or periodic stroking of the valve assembly.

pneumatic operator: a device that provides energy to open, close, or position a valve via pneumatic pressure.

preservice test: a test performed during the preservice test period to verify the capability of the valve assembly to perform its intended safety function.

preservice test period: the interval from completion of construction activities related to the valve assembly to the first electrical generation by nuclear heat in which component and system testing take place; or, in an operating plant, the interval to the valve assembly initially being placed in service.

seat load: the total net contact force between the valve closure member and the valve seat.

spring rate: the force change per unit change in length, usually expressed as pounds per inch or newtons per millimeter.

static test: test at ambient conditions without system pressure or flow.

stroke time: the time interval from initiation of the actuating signal to the indication of the end of the operating stroke.

total friction: the sum of packing friction, valve internal friction, and operator friction.

valve assembly, hydraulically operated: a valve and its associated hydraulic operator, including all components required for the valve to perform its intended safety function.

valve assembly, pneumatically operated: a valve and its associated pneumatic operator, including all components required for the valve to perform its intended safety function.

3 TEST GUIDANCE

The purpose of preservice testing is to verify the capability of the valve assembly to perform its intended safety function prior to initially placing the valve assembly in service. The purpose of performance testing is to monitor the valve assembly for degradation. Baseline testing is to establish baseline data for comparison to subsequent inservice test data. Inservice testing generates data to compare to baseline data and to assess the operational readiness of the valve assembly. Periodic stroking of the valve assembly ensures that the valve is not binding and that the valve operator is functional. Records of data should be prepared and maintained.

3.1 Preservice Test Guidance

Valve assemblies requiring preservice testing should be subject to the testing guidance of para. 4.3.1 prior to being initially placed in service to verify that valve assembly performance is in conformance with plant licensing requirements and capable of performing its intended safety function(s). Preservice testing should be accomplished prior to the end of the preservice test period.

3.2 Performance Test Guidance

Periodic performance testing should be performed in accordance with certain guidance.

3.2.1 Baseline Test Guidance. Valve assemblies should have a baseline test to establish reference values for comparison to subsequent inservice test data. The baseline test is performed when the valve assembly is initially placed in service and following activities that may affect the operating parameters of the valve assembly in accordance with para. 3.3. Testing should be in accordance with section 4, with test conditions in accordance with the guidance of para. 4.3.2.

3.2.2 Inservice Test Guidance. Valve assemblies should be tested in accordance with section 4 at a frequency established by the Owner.

3.2.3 Periodic Valve Assembly Stroke Test. Once during each plant cycle of operation, but not to exceed once per 24 months except to coincide with a refueling outage, valve assemblies should be operated to move the valves through one full stroke (open and close). If a valve assembly experiences a full stroke during the plant cycle of operation, the Owner may document such operation and no additional testing is required. No specific plant conditions apply to this test. The valve assembly stroke test is to ensure that the valve is not binding and that the valve operator is functional. No measurement of stroke time is required.

3.3 Equipment Replacement, Modification, Repair, and Maintenance Test Guidance

(a) When a valve assembly has been replaced, repaired, or has undergone maintenance that could affect the valve assembly's performance, new reference values should be determined or the previous value reconfirmed by an inservice test before it is returned to service or immediately if not removed from service. This is to demonstrate that performance parameters that could be affected by the replacement, repair, or maintenance are within acceptable limits. Deviations between the previous and new reference values should be identified and analyzed. Verification that the new values represent acceptable operation should be documented in the record of tests (see para. 4.7).

(b) A valve assembly affected by a design change that alters system operating parameters should be inservice tested to reconfirm or establish new reference values for those baseline parameters that could have been affected.

(c) A valve assembly modification that changes operating parameters should be inservice tested to reconfirm or establish new reference values for those baseline parameters that could have been affected.

4 TEST METHODS

Test methods should be applied to valve assemblies determined to be subject to the guide. Where the testing is performed other than in situ, the Owner is responsible for establishing conformance with the test methods.

4.1 Prerequisites

The Owner should identify valve assemblies to be tested in accordance with this paragraph. All performance testing should be in accordance with plant-specific installation, acceptance, maintenance, surveillance, or other applicable procedures.

4.2 Instrument Calibration

Instruments used for valve assembly tests should be checked to ensure their calibration is current in accordance with the Owner's Quality Assurance Program.

4.3 Test Conditions

4.3.1 Preservice Test Conditions. All preservice tests should be performed without any changes, modifications, or adjustments to the valve assembly during testing. A static test in combination with at least one of the following should be performed for preservice tests of valve assemblies:

(a) dynamic test at expected service conditions

(b) correlation with a similar valve assembly that has been dynamically tested at similar or bounding conditions

(c) extrapolation of results of dynamic tests at highest practicable conditions

(d) calculational methods, if it can be shown that the methods provide a conservative result

4.3.2 Periodic Performance Test Conditions. Tests should be performed without any changes, modifications, or adjustments to the valve assembly during testing. The Owner should determine the test conditions that apply to valve assemblies based on the selection of the test parameters in accordance with para. 4.6. The baseline test should be performed at specific repeatable conditions. The inservice tests should be performed at the conditions used to establish baseline values. Periodic valve assembly stroke testing may be performed at any plant condition that will not cause damage to the valve assembly.

4.4 Limits and Precautions

The plant should not be placed in an unanalyzed configuration that may cause a transient, or that places undue stress on a system or component, to obtain data during preservice or performance testing.

4.5 Test Procedures

Procedures should be established, as appropriate, to provide for

(a) methodical, repeatable, and consistent performance testing

(b) valid test data that are not influenced by any preconditioning associated with performance testing procedural steps

(c) data that reflects, or can be correlated with, the expected service conditions

(d) adequate data for analysis and evaluation per section 5

4.6 Test Parameters

4.6.1 Test parameters monitored will vary with the intended safety function(s) of the valve assembly. The safety function(s) normally fall(s) into one or more of the following:

(a) open within a specified minimum or maximum time period, or both

(b) closed within a specified minimum or maximum time period, or both

(c) stroke open to obtain minimum flow or pressure

(d) stroke open or closed against flow/pressure, including maximum differential pressure for the valve assembly to fulfill its safety function, across the valve

(e) travel to a predetermined intermediate position

(f) remain in operating position for specified period of time

(g) operate a specified number of cycles

4.6.2 The valve assembly is characterized by physical properties and design parameters including effective area, spring adjustment, spring rate, pneumatic or hydraulic pressure and volume, valve stroke (travel), friction forces, and proper setup of valve assembly components. The Owner should determine which of the following parameters, or combination of parameters, which may be determined from data obtained during testing, are important to monitor depending on the safety function(s) of the valve assembly:

(a) bench set

(b) maximum available pneumatic pressure

(c) seat load

(d) spring rate

(e) stroke time

(f) actual travel

(g) total friction

(h) minimum pneumatic pressure required to accomplish the safety function(s) of the valve assembly

(i) hydraulic pressure at appropriate point in operation

(j) pneumatic and hydraulic fluid condition and cleanliness

(k) set point of pressure switch, relief valve, regulator, etc.

(l) others as applicable

4.7 Test Information

The following information should be recorded and/or verified:

(a) test conditions per para. 4.3

(b) name of test performer

(c) date of test

(d) valve assembly identification

(e) nameplate data

(f) test equipment identification and date of calibration

(g) remarks concerning abnormal or erratic action, either during or preceding performance testing

(h) other important observations during testing

5 ANALYSIS AND EVALUATION OF DATA

The following analysis and evaluation of data guidance should be applied to valve assemblies determined to be subject to the guide. Where the testing is performed other than in situ, the Owner is responsible for establishing conformance with the guidance.

5.1 Acceptance Criteria

The Owner should establish acceptance criteria by which test data should be analyzed. The criteria should specify the acceptable limits or range of test parameters based on design criteria necessary for the valve assembly to perform its intended safety function(s). The baseline test establishes data for comparison to inservice test data and should be used to establish the acceptable limits or range for subsequent testing. Design criteria may include applicable vendor information, facility technical specifications and safety analysis reports, Owner-established requirements, and other related documents. The Owner may specify a corrective action value below the acceptable limit so that actions may be taken to correct degradation before the acceptable limit is reached.

5.2 Analysis of Data

Test data obtained from a test performed under this Part should be analyzed to determine acceptable valve assembly performance. Both operating and test conditions should be considered.

(a) The Owner should compare performance test data to the parameter limits or range established in accordance with para. 5.1. If data being compared fall within the acceptable range of established parameters, the values are acceptable.

(b) The Owner should consider test history on a particular valve assembly and should establish performance test data trends to predict when data points may approach the acceptable parameter limits. Corrective action should be taken prior to the valve assembly exceeding its acceptable parameter limits. If the test data is unacceptable, corrective actions should be taken in accordance with section 6.

5.3 Evaluation of Data

The Owner should establish guidelines for data evaluation that ensure the following:

(a) timely evaluation

(b) the valve assembly meets its established acceptance criteria and is capable of performing its intended safety function(s)

(c) corrective action is taken as described in section 6 if a valve assembly is not capable of performing its intended safety function(s)

5.4 Documentation of Analysis and Evaluation of Data

The Owner should document the results of test data evaluation and analysis, which should include, as a minimum, the following:

(a) assumptions made

(b) values of test parameters and test information established in accordance with paras. 4.6 and 4.7

(c) statement of confirmation of operational readiness as verified in accordance with Owner's Quality Assurance Program

(d) summary of analysis and evaluation of data in accordance with paras. 5.2 and 5.3

6 CORRECTIVE ACTION

If the results of a valve assembly test do not appear to meet the acceptance criteria established in section 5, the data should be analyzed within 24 hr. If the monitored parameters are outside acceptable limits, then corrective action should be initiated and the valve assembly should be declared inoperable. Valve assemblies declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and to show the valve assembly to be operating acceptably. If the Owner has also established a corrective action value that is below the acceptable limits, actions to correct degradation may be taken prior to declaring the valve assembly inoperable.

Plant-specific limiting conditions for operations should be followed if they are more limiting than this Part. The corrective action should bring the valve assembly back into compliance with acceptance criteria. When the corrective action consists of evaluating the acceptability of the valve assembly at the degraded conditions, new baseline data and acceptance criteria should be established. The valve assembly should be retested in accordance with section 4 following the corrective action and prior to return to service. The cause of the failure should be evaluated for identification of corrective actions to prevent recurrence in similar valve assemblies. Documentation of corrective actions should include the following:

(a) valve assembly identification

(b) summary of corrective action and results

(c) subsequent test data or analysis, including analysis for valve assembly operability

(d) identification of cause of anomaly and technical justification for corrective action taken

(e) description of actions taken to restore operational readiness of the valve assembly

Part 23
Inservice Monitoring of Reactor Internals Vibration in Pressurized Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part provides guidance for inservice vibration monitoring of reactor internals in Pressurized Water Reactor (PWR) power plants and recommends monitoring methods, intervals, parameters to be measured and evaluated, and record requirements.

1.2 Background

Figure 1 shows a cross-sectional view of a representative pressurized water reactor vessel and core support barrel. Flow-induced vibration of the core support barrel, fuel, and other internal structures act to change the thickness of the downcomer annulus (water gap) and affect the relative geometry of the fuel and surrounding structures. These variations cause small changes in the neutron flux sensed by ex-core power range neutron detectors located around the periphery of the reactor vessel (see Fig. 1).

The ex-core neutron flux signal is composed of a direct current component resulting from neutron flux produced by power operation of the reactor and a fluctuating signal or noise component. The fluctuating signal is composed of noise sources including reactivity response to temperature and pressure fluctuations; variations in neutron attenuation due to lateral and radial motion of the core support barrel and thermal shields; lateral motion of the fuel assemblies; and other potential vibration modes. These motions are usually very small sources of neutron noise but can be reliably identified in frequency spectra generated by Fourier analysis of the neutron noise signals to give spectral amplitude, phase, and coherence between signals from ex-core neutron detectors.

The natural frequencies and vibration of the reactor internals depend on their structural design and support conditions and on the vibration excitation mechanisms acting on them. Monitoring the neutron noise signals measured by the ex-core power range detectors has been shown to provide a means for detecting changes in the dominant internals structural conditions or vibration excitations.

The vibration characteristics of the reactor internals, for both as-built conditions and assumed degraded conditions, are determined by structural analysis and testing. The natural frequencies and mode shapes provide a basis for interpreting the significance of changes in the ex-core detector signals with respect to the internal structures and their support conditions. In addition to the ex-core neutron noise detector, other sensors can also provide supporting and supplemental data for detecting changes in the character of the internal structures and their support conditions. Accelerometers mounted on the reactor vessel [Fig. 1, illustration (a)] provide signals associated with loose parts impacting the reactor vessel and, in some cases, sounds associated with intermittent contact between internals components. In-core detectors [Fig. 1, illustration (b)] produce noise signals that can be used to monitor fuel assembly vibration and the motion of the in-core detector itself. An in-service monitoring program with well-coordinated loose-part monitoring accelerometers, in-core and ex-core neutron noise detectors, combined with comprehensive analysis and interpretation of the data, will enable an experienced engineer to detect changes in the condition of the reactor internals.

This Part should be implemented in a comprehensive program together with ASME OM-S/G–1997, Part 5, to routinely monitor the internals at power operation. The program should be defined in approved procedures, which identify the owners and users of the information obtained through the conduct of the program.

ASME OM-S/G–1990, Part 5, provides separate guidelines specifically for in-service monitoring for loss of core support barrel flange clamping force. Suitable review of the data acquired in this Part would, however, provide the information needed to detect anomalous core support barrel beam mode vibration.

2 DEFINITIONS

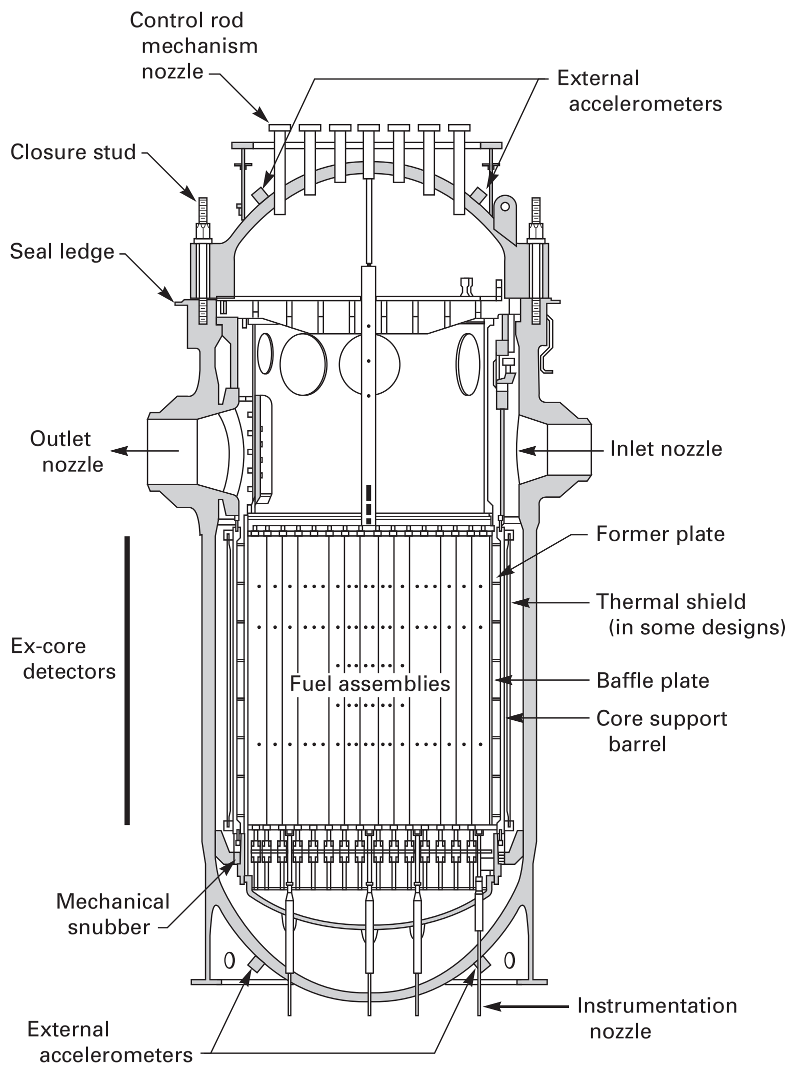
The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

amplitude probability density: a function of random data that describes the probability that the signal amplitude will assume a certain value within some defined range at any instant of time.

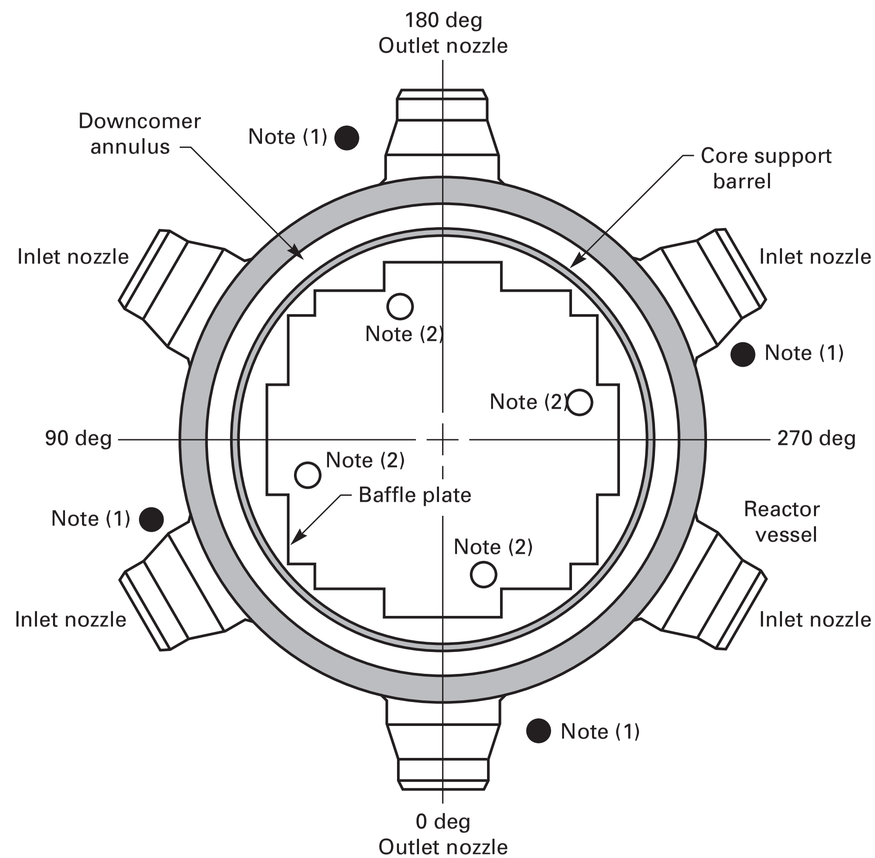
baffle jetting: localized flow from the region between the core support barrel and the core shroud into the region containing fuel assemblies.

bottom-mounted instrument thimbles: long, flexible pressure boundary tubes that pass through penetrations in the lower reactor vessel head and into fuel assemblies

Fig. 1 Schematic of a Pressurized Water Reactor (PWR) Showing Typical Sensor Arrangement



(a) Reactor Arrangement



NOTES:
(1) Ex-core detector
(2) In-core detector

(b) Ex-Core Detector Locations

to permit positioning miniature neutron detectors inside the core during reactor operation.

cantilever modes of vibration: vibration modes of a simple beam with one end clamped and one end free.

core baffle (or core shroud): the structure between the peripheral fuel assemblies and the core support barrel.

core support barrel: cylindrical structure located inside and concentric with the reactor pressure vessel that has the primary structural function of supporting the reactor core.

ex-core neutron detectors: neutron detectors, located outside of the pressure vessel and at the same elevation as the core, that are used to monitor neutron flux as an indication of reactor power.

fuel assemblies: a group of fuel rods, usually in a square array, spaced and supported by structural components.

in-core neutron detectors: miniature neutron detectors that can be positioned inside fuel assemblies to obtain local neutron flux measurements during reactor operation.

mechanical snubbers: in a reactor, dynamic restraint devices in which load can be transmitted between tabs on the core support barrel and adjacent tabs on the inside of the reactor vessel.

natural frequency: the frequencies at which a system will vibrate in the absence of any external forces.

neutron noise: fluctuations in the neutron signal from a reactor operating at steady state. These fluctuations are considered noise for the measurement of reactor power, but contain information that can be correlated to structural motion and thermal hydraulic effects.

pump-induced vibrations: structural vibrations driven by mechanical coupling of reactor coolant pumps to the reactor vessel and by pump outlet pressure pulsation transmitted through the reactor coolant.

shell modes of vibration: vibration modes of cylindrical shell structures involving displacements primarily in the radial directions.

thermal shield: a steel cylinder mounted on the outside of the core support barrel to attenuate radiation and the associated radiation heating of the pressure vessel.

The following terms pertaining to random data analysis are defined in ANSI S2.10 (1971): *autopower spectral density function (APSD), coherence function (COH), cross-power spectral density function (CPSD), cross-spectral density, power spectral density (PSD),* and *root mean square (rms).*

(15) 3 REFERENCES

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ANSI S2.10-1971, "Methods for Analysis and Presentation of Shock and Vibration Data"

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036 (www.ansi.org)

ASME Boiler and Pressure Vessel Code (BPVC) 1998, Section III, Appendix N

ASME OM-S/G–1997, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 5, "Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants"

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

4 INTERNALS VIBRATION EXCITATION SOURCES, RESPONSES, AND MODES

4.1 Sources of Excitation and Responses

Under normal operating conditions, reactor internals vibrations could be induced by the following excitation sources: flow turbulence; pressure pulsation and mechanical motions produced by the reactor coolant pumps; vortex shedding; and fluidelastic forces. The characteristics of these excitations are described in the following paragraphs.

4.1.1 Flow Turbulence. Flow turbulence is mainly generated by changes in the boundaries of the flow paths, causing random fluctuating forces to act on the flow channel surfaces. The magnitude of these forces decreases with increasing frequency. The dominant responses are narrowband peaks around the structural natural frequencies.

4.1.2 Pump-Induced Excitations. These excitations are at the pump rotating speed and impeller blade passing frequency (pump rotating speed times number of impeller vanes) harmonics. The waveform is composed of a series of sinusoidal, harmonically related tones. The overall waveform contains sinusoidal vibrations from all running reactor coolant pumps. Because of this, time variation of the overall waveform due to constructive and destructive interference is likely due to both phase and pump speed variations. An example of this space-time variation of coolant pump-induced excitation is given in Nonmandatory Appendix C of this Part, Fig. C-3.

4.1.3 Vortex Shedding. Vortex shedding due to flow perpendicular to the axis of cylinders produces sinusoidal or narrowband random forces. The resulting forces are generally significant only when the vortex shedding frequency is close to a structural natural frequency.

4.1.4 Fluidelastic Excitations. These forces are generated by flow perpendicular or parallel to the axis of a cylinder or an array of cylinders. The forces do not exist when the structure has no motion. The waveform is nearly sinusoidal at the natural frequencies of the coupled fluid-structural system.

Additional information and methods for calculating vibrations induced by these forces are given in Au-Yang (1986), Mulcahy (1983), and ASME BPVC 1998, Section III, N-1300 and 1400.

4.2 Vibration Modes

4.2.1 Types of Modes. Internals vibrate in axial, lateral, and torsional modes. Axial modes are formed by axial extensions and compressions of the structures, bending of plates, and end flange flexibilities. Lateral modes can be breathing, shell, or beam modes (Fig. 2). Torsional modes are produced by twisting of the structures, as commonly associated with shafts. In para. 4.2.2, the modes are denoted by the structure or component that dominates the vibration of the mode. It should be recognized, however, that several structures or components usually participate to some extent in these modes.

4.2.2 Dominant Internals Modes and Their Characteristics in Ex-Core Detector Noise Signals. Although several components participate in structural modes, specific modes are commonly associated with the structure that has the dominant response. The dominant modes generally detectable in the ex-core detector are described.

(a) Core Support Barrel Beam Modes. These are generally cantilever modes in which there is some participation of the reactor vessel, fuel assemblies, and the circular thermal shield. In some cases, contact at the snubbers at the lower end of the core support barrel may result in a higher frequency mode. Preloads at the snubber may result in a clamped-pinned mode. In other cases, intermittent contact at the snubbers might result in nonlinear modes.

(b) Fuel Assembly Beam Modes. These modes occur at fuel assembly natural frequencies and are detectable in ex-core detector signals. The core support barrel has some participation in these modes.

(c) Core Support Barrel Shell Modes. There are generally more than one of each ($N = 2$, $N = 3$, etc.; see Fig. 2) of these modes. However, a detector might not be able to pick up one or more of these modes if it is located near a node (zero vibration amplitude) point of the mode(s).

(d) Thermal Shield Shell Modes. These modes occur in the same manner as the core support barrel shell modes. The dominant motion is the thermal shield and there is some participation of the core support barrel for designs that have circular thermal shields.

5 SIGNAL DATABASE

5.1 Signals to Be Monitored and Reactor Conditions

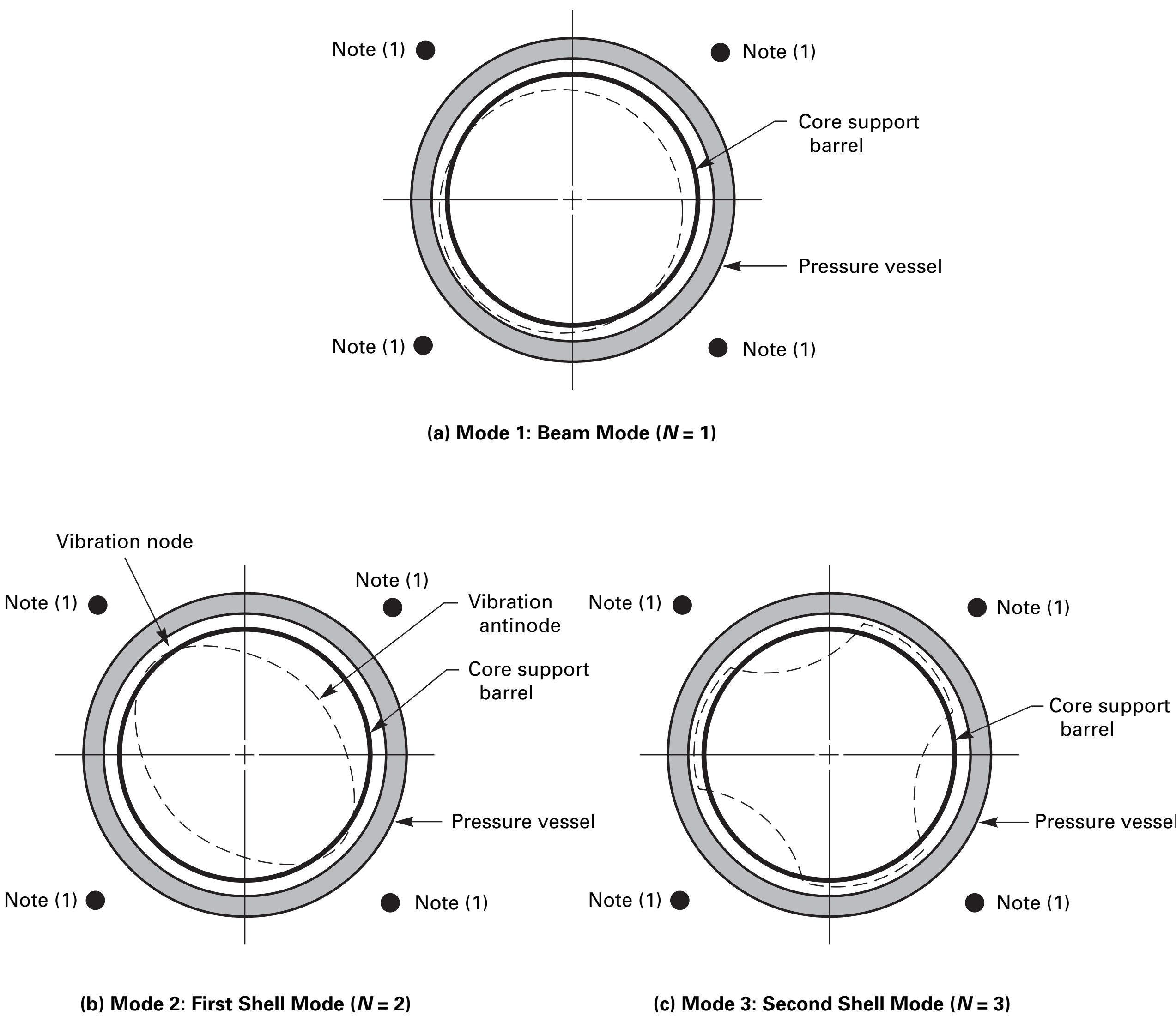
Table 1 lists detector types with potential applications drawn from past vibration and noise monitoring experience. The program defined in this part requires only that ex-core detector signals be monitored. The other detectors may be used to broaden the database. Data acquisition for each type of detector is discussed in the following paragraphs. The functions to be generated during data reduction are discussed in para. 5.5.

During data acquisition, the reactor should be at a steady power level, there should be no control rod movement or boron dilution or injection.

5.2 Data Acquisition

The equipment necessary for acquisition of the required signals includes devices to buffer signals to isolate the data acquisition activities so that other plant systems are unaffected; devices to block or remove the DC signal; amplifiers to increase signal levels to provide the maximum available signal-to-noise ratio; filters (low-pass, high-pass, band-pass, band-reject) to reduce the effects of signals not related to core internals vibration, to limit the frequency bandwidth of the signal, and to prevent aliasing in digital systems; and devices to analyze the data, record the data for later analysis, and provide storage of signals or analysis results. Figure 3

Fig. 2 Beam and Shell Mode Vibration of a PWR Core Support Barrel



GENERAL NOTE: *N* is the number of full sine waves around the circumference of the structure.

NOTE:

(1) Ex-core neutron detector.

Table 1 Sensor Types and Potential Applications in Reactor Noise Analysis

Detector	Typical Useful Frequency Range, Hz	Potential Applications
Ex-core power range ionization chambers	<100	Core internals vibration monitoring
In-core neutron detector		
Fission chamber	<100	Coolant velocity measurements (PWR)
Fast SPND	<100	Fuel assembly vibration (PWR)
Rhodium SPND	<10	TIP tube vibration (BWR)
Vibration monitoring		
Accelerometers	10–10,000	Structural vibrations
Displacement	10–10,000	Pump monitoring
Temperature		
RTD (no thermal well)	<1.0	Flow monitoring

shows the typical arrangement of equipment in a data acquisition system.

The implementation of a data acquisition program should include the equipment listed above, testing and calibration of the equipment, and data validation and documentation. Signal buffering is necessary to isolate the noise data acquisition system from other plant systems and to prevent the contamination of the noise data by other devices sharing the signal. Test and calibration of the data acquisition system by introducing a signal of known characteristics verifies that the equipment tested is functioning properly and determines the gain, frequency response, and noise characteristics of the calibrated equipment. Signals should be recorded on analog or digital magnetic tape, magnetic disk, optical disk, or other analog or digital mass data storage devices. Signals may also be analyzed online and the results as well as the original data recorded.

5.3 Signal Sampling

Data reduction for recording and noise analysis involves conditioning the signal for analysis, sampling analog noise signals, time or frequency domain analysis, display of results, and validation of results.

Analog noise signals should be amplified to sufficient levels to be accurately represented in digital format. However, the signals must not overload the analog to digital converter or conditioning amplifier. Noise signals also should be filtered to prevent aliasing. Sampling analog signals at a given time interval, ΔT, yields data of a selected time resolution for correlation analysis or of a selected frequency bandwidth for spectral analysis. Spectral analysis with digital computers uses the Fast Fourier Transform (FFT) algorithm in which the sampling rate $1/\Delta T$, the sample block size n, the frequency resolution Δf, the statistical accuracy as measured by the normalized error, and the total length of time record T are all interrelated as shown in Table 2. Nonmandatory Appendix D of this Part gives an example on selection of these parameters for signal sampling.

5.4 Signal Recording

Data may be digitally recorded or recorded on an analog recorder. Information to be documented is included in para. 5.7. Nonmandatory Appendix D of this Part provides additional information on sampling rates for digital recording and length of data record.

5.5 Data Reduction

5.5.1 Frequency Spectral Functions. Frequency spectral functions useful in the analysis of the detector signals are included in Part 5 and ANSI S2.10.

Further clarification of signal content can be obtained by separating the frequency spectral content of signal pairs into in-phase and out-of-phase contents of these two signals. This technique is described in Nonmandatory Appendix A of this Part.

Specific spectral functions for ex-core detectors are provided in para. 5.5.2.

5.5.2 Ex-Core Detectors. Beam and shell modes of the core support barrel and thermal shield due to flow turbulence and pump-induced vibrations can be detected by the ex-core neutron detectors. The vibration of fuel assemblies near the detectors is also reflected in the signals of these detectors.

Data should be acquired to permit generation of at least 0 to 50 Hz frequency spectra with a frequency resolution of 0.15 Hz or less; 100 blocks of data are recommended for statistical accuracy. The signals are normalized to their DC voltages. This is designated by "N" preceding the spectral function listed below. The following functions should be generated:

(a) normalized power spectral densities (NPSD) of all detectors at the lowest detector section elevation or the average of more than one elevation including the lowest. Acquisition at the lowest and highest detector section elevations is preferred.

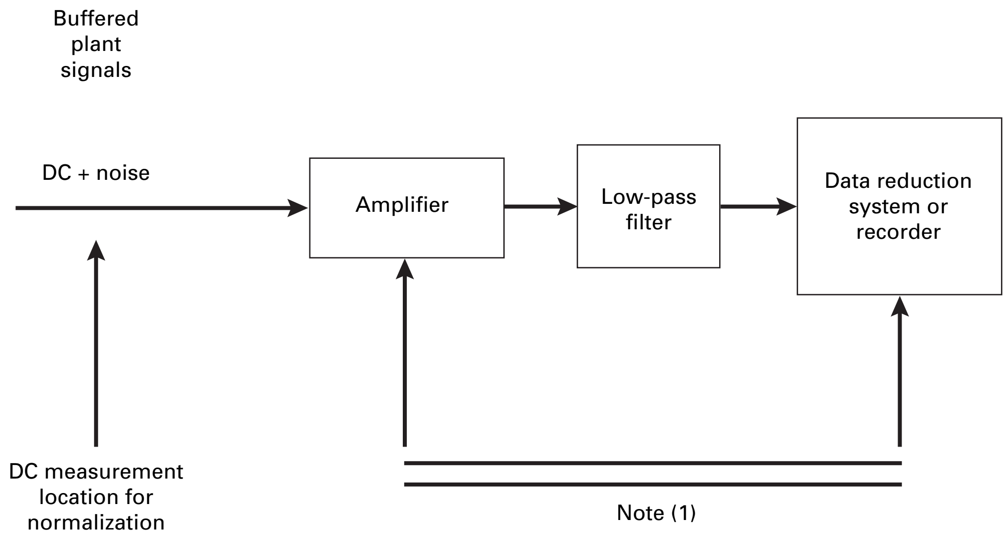
(b) normalized cross-power spectral densities (NCPSD), magnitude and phase, and coherence for all detectors from at least one elevation. Upper-to-lower pair CPSDs should be considered in cases of extra long fuel cycles or when anomalies are detected.

(c) a time history sample of all detectors.

The information in Nonmandatory Appendix D of this Part should also be considered for record length and sampling guidance.

Data should be acquired at full power during the first and last 30 to 90 effective full-power days (EFPD) of

Fig. 3 Typical Components in a Signal Data Acquisition System



NOTE:
(1) Gain of entire system must be known for proper normalization.

Table 2 Relationships Between Sampling Rates and Analysis Results

Quantity	Relationship
Sampling interval	ΔT
Sampling rate	$f_s = 1/\Delta T$
Maximum (Nyquist) frequency (Hz) [Note (1)]	$1/(2\Delta T)$
FFT sample block size (number of data points per block)	n (must be 2^k where k is an integer)
FFT spectrum lines [Note (1)]	$^n\!/_{2+1}$ (including $f=0$)
FFT frequency resolution (Hz)	$\Delta f = 1/(n\Delta T)$
Number of correlation lags (inverse FFT of block spectra)	$(n/2)-1$
Correlation length(s)	$(n-1)\Delta T$ blocks
Number of data blocks	N (100 blocks is recommended)
Total length of time record needed	$T = Nn\Delta T$
Normalized error in PSD estimate	$\epsilon = 1/\sqrt{N}$

NOTE:
(1) This is the theoretical maximum. In practice, the useful maximum frequency is less than the theoretical maximum and usually varies between $1/(2.2\Delta T)$ and $1/(3.0\Delta T)$ depending on the slope and set point of the anti-aliasing filter.

each cycle. Additional data collection such as at mid-cycle and partial power should also be considered.

5.5.3 In-Core Detectors. These detectors can be used to obtain information on fuel assembly vibration. The detectors can be located at grid or mid-span elevations for this purpose. When positioned at an elevation that is within the flux gradient near grids, vertical motion of the assembly, if any, can be inferred from the signals. In some designs, these detectors can also detect vibration of the in-core thimble at elevations within the fuel assembly.

Uranium-lined (fixed or movable) in-core detectors are used in some plants. These detectors have a good high-frequency response, limited only by the electronics and cables. The noise signals do have a white noise background due to Campbelling (Knoll, 1989) that could mask lower level neutron noise signals. Core support barrel, fuel assembly, and thimble vibrations well above these levels have been observed.

Self-powered rhodium fixed in-core detectors are used in some plants. The large majority of the signal from this type of detector has a time constant of approximately 1 min. This is too slow to be practical for nuclear noise applications. A small fraction of the signal is fast. Glockler et al. (1986) provides vibration monitoring experience in Europe using in-core self-powered neutron detectors (SPND). Methods for dynamic compensation of rhodium SPNDs have been reported by Hoppe and Maletti (1992).

Some plants use plutonium self-powered fixed in-core detectors. The signals from these detectors have a good high-frequency response and, therefore, their use for neutron noise monitoring is feasible.

The time history of the noise signal should be recorded at each location. All noise signal levels should be normalized to the steady state signal level. The steady state (or DC) voltages at each location should be documented at the beginning and end of the data acquisition.

NPSDs should be generated for all detector signals. If these are generated using a two-channel spectrum analyzer, selections of initial signals to be paired should be pairs that will provide information regarding

(a) modes that are confined to individual fuel assemblies

(b) modes in which the core support barrel participates

Data from selected in-core detector signals should be recorded with ex-core detectors. Modes dominated by fuel assembly and core support barrel motion commonly appear in in-core detector neutron noise signals. Cross-analysis of in-core detector pair signals, in-core/ex-core detector pair signals, and information on expected modal frequencies can support identification of these responses in the in-core signals. Data should be acquired during the first 30 to 90 EFPDs of the first fuel cycle of this program and each time a component design is changed.

Guidelines for the selection of elevations at which data should be acquired are provided below.

5.5.3.1 Movable Detectors. For each reactor having movable detectors, one or more detectors are inserted to a selected elevation. Data are acquired following the guidelines for record length given in para. 5.5.2. The detectors are moved to and data are acquired at several elevations. A data acquisition plan should be made to establish the core locations and elevations at which data should be acquired.

Since data is only obtained at one elevation at a time using movable detectors, information on the phase differences between elevations is not available. Expected fuel assembly vibration mode shapes can be used to assign likely relative phases to support interpretation.

5.5.3.2 Fixed Detectors. Data at all elevations of at least one thimble location should be acquired simultaneously.

5.5.4 Loose-Part Monitoring Accelerometers. The purpose of these accelerometers is to detect the impact of loose parts against the primary coolant system (Part 5). They have also been used in monitoring for degradation of thermal shield supports in some designs (see Kosaly). Correlating the vibration analysis results of the core support barrel and thermal shield system and the neutron noise data analyses with loose-part monitoring data analysis yields supporting and supplemental information on the condition of the thermal shield supports in those designs.

Some systems might permit acquisition of low frequency data. For these systems, reactor vessel and core support barrel vibration might also be detected by these accelerometers (depending on their locations, directions of sensitivity, and signal filtering), providing an independent measurement where detectable.

Signal spectra from accelerometers mounted on the reactor vessel acquired at the same time as the ex-core detector signals should be included in the database. If the low frequency content of these signals has a suitable signal-to-noise ratio to permit detection of the expected vibration modes, the signals should be double-integrated to generate displacement spectra up to 50 Hz. In some systems, alarm discrimination may require the signals be high-pass filtered at 500 Hz or higher. However, the raw signal obtained directly from the accelerometers can be good down to 10 Hz.

5.6 Data Storage

Data should be stored to permit comparison of signal time history samples and NPSDs of each detector. The real-time correlation of all time histories of each detector type should be preserved. Nonmandatory Appendix D of this Part also provides guidance regarding storage of time history samples.

Ex-core and in-core detector data should be stored to permit generation of NCPSDs and coherence spectra between selected in-core pairs and selected in-core/ex-core pairs.

The data should preferably be stored in digital format either as ASCII files or any other file structure for which the program to convert to ASCII must be available and maintained for the life of the monitoring program. The documentation of para. 5.7 must be recorded at the beginning and, if applicable, at the end of data acquisition. This method of storage provides the best assurance that the data can be readily and accurately reproduced at a later time. Storage of data in nondegradable digital media such as optical disk or CD-ROM is preferred, though the data may be stored on digital or analog magnetic tapes. To prevent the data from being degraded by the external elements, including magnetic fields (such as the Earth's magnetic field), over a length of 10 yr to 20 yr, these tapes should be protected by soft-iron cases. Storage of the original data time series is preferable to storing the spectral analysis results because it enables the data to be reanalyzed in the future.

5.7 Documentation

The following information should be recorded at the beginning of data collection. Any parameter (e.g., data and time, power level, boron concentration) that changes or may change during the time required to complete recording or analysis should also be recorded at the end of the data acquisition time.

(a) Data acquisition information that should be maintained for documentation is the following:

(1) plant name and unit number

(2) data and time of data acquisition

(3) plant conditions [power level, coolant flow rates, number of pumps operating, system temperatures and pressure, control rod positions, soluble boron concentrations, fuel burnup (EFPD), fuel cycle number, and any additional information needed for the interpretation of results]

(4) name of person or persons performing data acquisition and identification of data acquisition system or components

(5) identification of signals

(6) description of plant sensors including manufacturer, model number, serial number, and calibration or other identification such as plant part number

(7) description of signal conditioning equipment

(8) gains of amplifiers

(9) types of filters (e.g., low-pass, high-pass analog, digital) and cut-off frequencies

(10) DC voltages measured at the input of the signal-conditioning equipment (if available) or calculated from the power level

(11) log of observations or unusual occurrences, especially plant transients, during data acquisition

(b) Data recording information that should be maintained for documentation is the following:

(1) description of recorder

(2) gain setting of the recorder

(3) location of beginning and end of record and calibration signals

(4) identification of data recorded

(5) tape speed and bandwidth of recording for analog records or sampling rate, antialiasing filter set point, and file name for digital recording

6 DATA REVIEW

6.1 Initial Data Set

6.1.1 All Detector Signals in the Database. The initial data from the signals of all detectors included in the signal database should be reviewed for validity of the signals and the likely source of the dominant signal content. Data validity is established by reviewing the data acquisition documentation for completeness and consistency and by checking the signals for high 60 Hz noise or other electrical noise, overloads, signal spiking, loss of signal, and dynamic range. Data validation can be accomplished by visual examination of the time traces (strip charting) or by amplitude probability density (APD) analysis.

If this review results in significant uncertainty regarding the validity of the data, or its spectral content, another set should be recorded within 30 EFPDs of the original data acquisition. If the results of review of the second data set do not provide a reasonable basis for interpretation of the data, or if anomalous behavior of the core internals is considered likely, a specific plan should be established to support interpretation or identify the anomalous content.

6.1.2 Ex-Core Detectors. Ex-core detector signals data should be reviewed for the mode types and sources (e.g., core support barrel beam mode and thermal shield shell mode). The results should be compared to the expected responses obtained from one or more of the following:

(a) laboratory testing

(b) preoperational prototype vibration measurement programs

(c) fluid/structure analytical models

Guidelines for identification of core support barrel beam modes are included in Part 5. In some cases, the thermal shield and core support barrel system result in beam modes that should be similarly identified.

Ex-core neutron noise data are also used to monitor shell modes that are dominated by vibrations of the thermal shield or core support barrel. The lateral vibration shapes of these modes are shown in Fig. 2. Beam and shell modes can be identified by the phase differences between detector pairs.

The $n = 2$ mode usually has the larger shell mode response and should be identified in the data during the baseline phase of the program.

Figure 2 shows that for beam modes and $n = 3$ shell modes the cross-core detectors are out of phase, whereas for $n = 2$ shell modes the cross-core detectors are in phase. The vibration modes may be either in phase or out of phase with respect to cross-core detector pairs. Breathing modes in which the circular section remains circular are $n = 0$ shell modes. These modes are of higher frequency and lower amplitude and are not readily apparent in vibration plots. Phase separation techniques using the cross-power spectral density function for the cross-core detector pairs and their associated coherence or by analysis of sum and difference signals can also be used in the data reduction to assist in identification of modes (see Nonmandatory Appendix A of this Part).

6.1.3 In-Core Detectors. Data from these detectors are not required but may be used to supplement other data for diagnosis.

The signals of these detectors should be reviewed with the intent of identifying the beam modes of fuel assemblies and content that might be related to thimble motions and core support barrel vibration. Expected fuel assembly beam mode natural frequencies are available from the fuel designers. Fuel assembly vibration amplitudes are not readily deduced from these data. Fuel assembly motion related to core support barrel motion can be investigated by cross-correlation of in-core detector and ex-core detector noise signals.

6.1.4 Loose-Part Monitoring Accelerometers. The unfiltered or low-pass filtered signals of these data, if available, should be reviewed for low-frequency content that might be related to core support barrel/reactor vessel system beam modes.

6.2 Subsequent Data Sets

6.2.1 All Detector Signals. The data should be reviewed for validity in accordance with para. 6.1.1 and for similarity with previous data. Ex-core data should be reviewed in accordance with para. 6.2.2.

6.2.2 Ex-Core Detector Signals. The following data is useful in relating changes in the data to changes associated with structural degradation:

(a) past variations when no structural degradation was found

(b) past variations when structural degradation was found

(c) experimental data with implanted defects

(d) analytical models with postulated structural degradation

(e) data from other plants that experienced structural degradation

It should be recognized that structural degradation must be significant before a detectable change in the monitored signals is produced. Loosening of one fastener on a joint that has multiple fasteners, for example, is not likely to be detectable.

Much of the information for detailed baseline studies and for studies of the structural integrity of the thermal shield is obtained from analysis of signals from neutron noise detector pairs, as discussed above. However, single channel information (such as auto spectra and narrowband/broadband rms displacements) give quick comparisons between the present and past data sets to establish a trend.

Conversion from neutron noise spectra to displacement spectra and rms displacements of the thermal shield follows the same equations given in Part 5. Information on conversion factors for thermal shield vibration is given in Kosaly. Since the conversion factors are only approximate, the computed rms displacements and displacement spectra should be used for comparison purposes only.

As the fuel cycle progresses, it is not uncommon to see the spectra peaks deteriorate slightly in some designs. This is caused by the relaxation of clamping forces, causing slight decreases in its stiffness and natural frequencies. As long as the change is small, it should not be a source of concern. In addition, burnup effects may cause increases in spectrum levels as the fuel cycle progresses that should be considered in establishing surveillance criteria. Reductions in the center frequencies of fuel assembly responses attributed to grid relaxation have also been reported (Sweeney et al., 1983).

Correlating the free vibration analysis results of the core support barrel/thermal shield system and the neutron noise data analyses with loose-part monitoring data analysis might support and supplement information on the condition of the thermal shield supports, as was demonstrated by Lubin et al. (1988).

Part 23, Nonmandatory Appendix A
Discussion of Spectral Functions

This Nonmandatory Appendix gives a brief description of various parameters (see Bendat and Piersol, 1971) used in baseline, surveillance, and diagnostic programs to identify core support barrel motion. It should be noted that all parameters are normalized to the operating power level (the DC value of the ex-core detector signal).

A-1 NORMALIZED POWER SPECTRAL DENSITY (NPSD)

The normalized power spectral density (the auto-power spectral density or APSD divided by the DC signal level squared) is a decomposition of a stochastic function into functions of frequency [see Fig. A-1, illustration (a)]. It provides a measure of the signal power (mean square level) within discrete frequency bands over specified frequency ranges, normalized to the reactor power level. Because the PSD is in units of volts^2/Hz, and the NPSD is the PSD divided by the DC voltage squared, the units of the NPSD are 1/Hz. The sampling rate, sampling time, and sample size are governed by the relationships in Table 2 of Part 23.

A-2 NORMALIZED ROOT MEAN SQUARE OF THE SIGNAL

The normalized root mean square (nrms) value of the neutron noise signal is a measure of the amplitude of core support barrel motion. However, it may include systematic variations due to changing plant conditions (e.g., burnup), changes in $\beta_E FF$ (delayed neutron fraction) reactivity coefficients, and the like, which can contribute to a change in the nrms level. Since the nrms level is normalized to the DC level, it is dimensionless.

The rms value of the band f_1 to f_2 can be computed from NPSD as

$$(\mathrm{nrms})^2 = \int_{f_1}^{f_2} \mathrm{NPSD}\, df$$

NSPD can be used to calculate that portion of the total ex-core response related to core support barrel motion. Observed over an extended period of time, it provides a measure of changes in vibration.

A-3 NORMALIZED CROSS-POWER SPECTRAL DENSITY (NCPSD), COHERENCE (COH), AND PHASE (*N*)

A-3.1 Normalized Cross-Power Spectral Density (NCPSD)

The NCPSD (the cross-power spectral density or CPSD divided by the product of the DC level of the two signals) provides a descriptor of commonality between two encore detectors [see Fig. A-1, illustration (b)]. The ability of the NCPSD to discount noncoherent portions of the signal better defines the region of motion and, when used in conjunction with the coherence and phase, is preferred over the NSPD for establishing core support barrel motion. The rms value over frequency band f_1 to f_2 can be computed as the following:

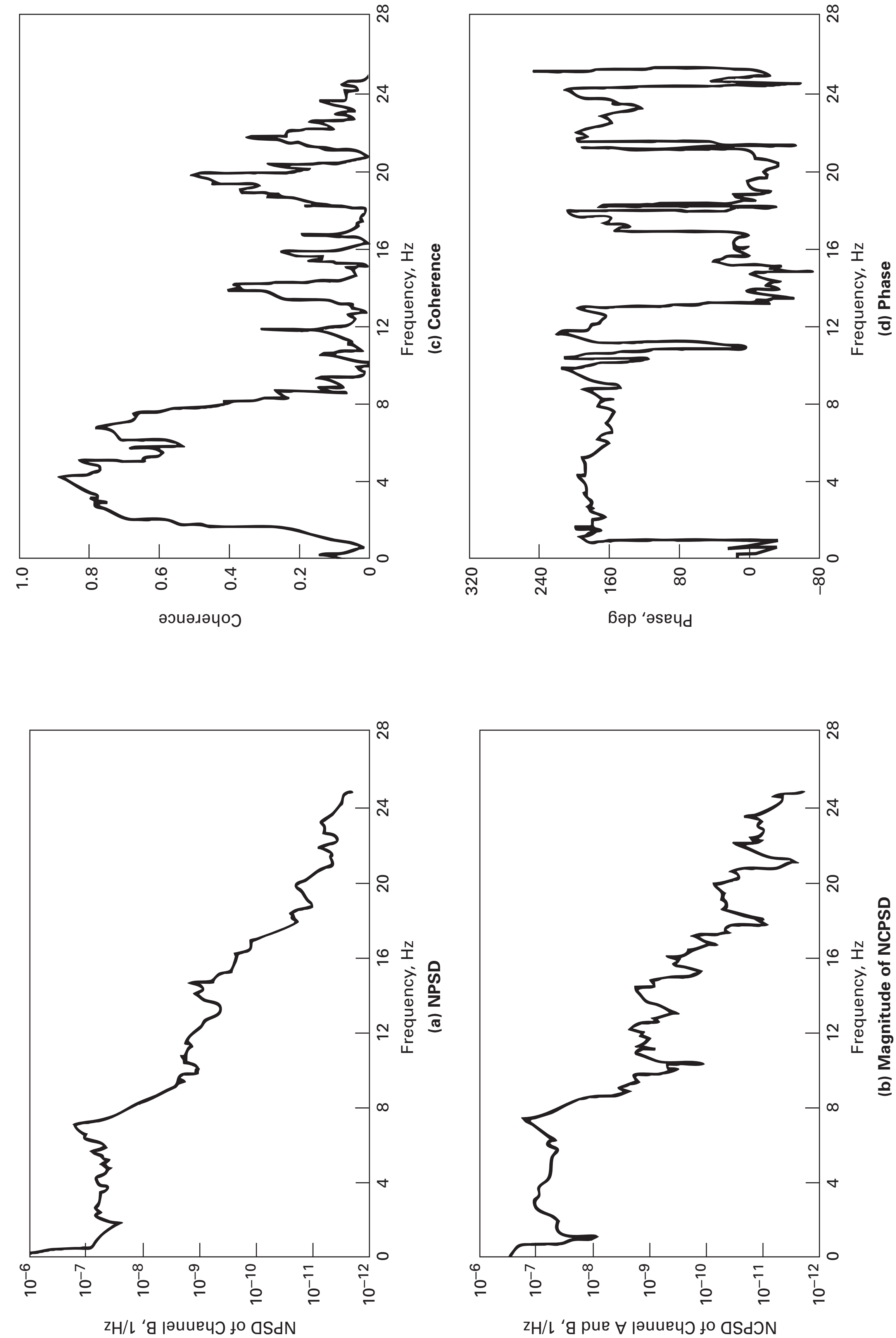
$$(\mathrm{nrms})^2 = \int_{f_1}^{f_2} \mathrm{NCPSD}\, df$$

The NCPSD is expressed as the product of signal voltages per product of DC voltages per unit of frequency, and has units of (1/Hz).

A-3.2 Coherence (COH) and Phase (*N*)

Although the NCPSD is a measure of the commonality between two variables, it is most convenient to represent the similar character in relative terms, relative to the individual signal NPSDs. This is done by calculating the coherence function. The coherence is defined as the ratio of the square of the magnitude of the NPSD to the product of the individual NPSDs and is bounded between zero and one [see Fig. A-1, illustration (c)]. If the coherence is one, the two signals are said to be fully coherent and, therefore, closely related. The corresponding phase data in this case are valid. Uncorrelated signals will have a coherence approaching zero, which means that the phase data is meaningless [see Fig. A-1, illustration (d)]. Coherence is dimensionless, while phase is expressed in degrees. Generally, for neutron noise signals, a coherence above 0.5 is considered good.

Fig. A-1 Different Spectral Functions



A-4 IN-PHASE AND OUT-OF-PHASE SIGNAL SEPARATION (MAYO, 1977)

Rigid-body lateral motion of the core and core support barrel, such as in the cantilever mode of vibration, produces coherent, out-of-phase (180 deg) signals between ex-core detectors located on opposite sides of the core. Geometric arguments can also be made that thermal shield and/or core support barrel shell modes produce either in-phase (0 deg) or out-of-phase signals between all ex-core detector pairs. Global reactivity fluctuations caused by mechanisms such as standing pressure waves or vertical core vibration produce in-phase signals between all detectors. Ex-core neutron noise signals typically contain multiple components with in-phase and out-of-phase relationships.

Overlapping in-phase and out-of-phase signals add or subtract from each other in the CPSD and coherence functions. Where this occurs, the CPSD has the phase of the larger signal while the magnitude of the CPSD and coherence are reduced due to partial cancellation. If the dominant signal component has a fairly smooth spectrum and the opposite phase signals have some structure, a peak in the lower magnitude process appears as a negative image in the magnitude of the CPSD and coherence. Where the magnitudes of the in-phase and out-of-phase signals are exactly equal, as at points where the spectrum transitions between dominant signal types, the magnitude of the CPSD and the coherence go to zero. This interference between in-phase and out-of-phase signal components increases the difficulty of interpreting the CPSD and coherence functions.

If the neutron noise signals are primarily composed of in-phase and out-of-phase noise sources, it is possible to obtain separate power spectral densities for the in-phase and out-of-phase signal components. This separation is no more than selective cancellation of the out-of-phase or in-phase signal components by adding or subtracting the noise signals from detectors located on opposite sides of the core.

The signals from two detectors that are responding to two independent processes, one in-phase and one out-of-phase between the detectors, can be represented as

$$S_1(t) = X(t) + Y(t)$$

$$S_2(t) = X(t) - Y(t)$$

Adding these signals cancels $Y(t)$ while reinforcing $X(t)$. Subtracting them cancels $X(t)$ while reinforcing $Y(t)$. This can be done with analog electronic circuits and the power spectral densities for X and Y can be calculated from the resulting sum and difference signals. In some cases, neutron noise analysis is performed by calculating the auto- and cross-power spectral densities, phase, and coherence functions without the possibility for prior addition or subtraction of the detector signals. In this situation, the power spectral densities of the in-phase and out-of-phase signal components can be calculated by the following:

where the phase of CPSD(ω) ≥ 0

$$\mathrm{PSD}Y(\omega) = \frac{1 - \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

$$\mathrm{PSD}X(\omega) = \frac{1 + \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

or where the phase of CPSD(ω) ≤ 0

$$\mathrm{PSD}Y(\omega) = \frac{1 + \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

$$\mathrm{PSD}X(\omega) = \frac{1 - \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

The PSD of either signal 1 or signal 2 can be used interchangeably in this form as it can be shown that

$$\mathrm{PSD}S_1(\omega) + \mathrm{PSD}S_2(\omega) = \mathrm{PSD}X(\omega) + \mathrm{PSD}Y(\omega)$$

The effectiveness of this separation of in-phase and out-of-phase signals depends on the absence of incoherent noise and noise sources with other than 0 deg and 180 deg phase between the detectors. This condition can be validated by the phase and coherence between $S_1(f)$ and $S_2(f)$. Where the measured signals are dominated by in-phase and out-of-phase processes, the measured phase will be either 0 deg or 180 deg. Also, as indicated by the equations for signal separation in the frequency domain, the separation will fail in the presence of dominant incoherent noise due to the coherence going to zero and so that

$$\mathrm{PSD}Y(\omega) = \frac{1}{2}\,\mathrm{PSD}S_i(\omega) = \mathrm{PSD}X(\omega)$$

The presence of a significant difference in the magnitude of PSD$X(\omega)$ and PSD$Y(\omega)$ indicates the absence of incoherent noise. This condition and phase values of 0 deg and 180 deg between $S_1(\omega)$ and $S_2(\omega)$ indicate that the in-phase and out-of-phase signal separation process is valid.

In some cases, measurements have shown cross-core neutron noise signals to be remarkably free of incoherent noise and that the dominant signal components are either in-phase or out-of-phase over almost the entire frequency range of ex-core neutron noise. For these measurements, the phase-separated spectra have improved the observability of core support barrel cantilever and shell vibration modes and global reactivity noise. In other cases, and particularly in plants using low leakage fuel management and at later times in fuel cycles, incoherent noise has been present that substantially reduces the separation of in-phase and out-of-phase signal components. The quality of in-phase and out-of-phase signal separation should be examined in each application.

The separation of in-phase and out-of-phase signal components between neutron detectors that are not located on opposite sides of the core is of limited value. This is due to independence in the *X* and *Y* components of core support barrel cantilever mode vibration. Fully coherent signals for this vibration mode can be obtained only by detector pairs that are on directly opposite sides of the core where they respond to a single direction of motion.

A-5 REFERENCES

The following is a list of publications referenced in this Nonmandatory Appendix:

Bendat, J. S., and Piersol, A. G., 1971, "Random Data Analysis and Measurement Procedures," Wiley Interscience, New York

Mayo, C. W., 1977, "Detailed Neutron Noise Analysis of Pressurized Water Reactor Internal Vibrations," Atomkernenergie, Bd. 29, Lfg. 1

Part 23, Nonmandatory Appendix B Supporting Information on Component Vibrations

B-1 IN-CORE DETECTOR THIMBLES

B-1.1 Introduction

Tubular thimbles guide the in-core detectors and provide a pressure boundary between the reactor coolant and the containment atmosphere. The thimbles are fixed in position when the plant is operating. The detectors are either fixed during operation or travel in and out of the thimbles during use. The outside of the thimble has a nominal clearance with the guide tube in the fuel assembly and the detector has a nominal clearance with the inside of the thimbles. Experience indicates that the support points between the thimble and the guide tube and between the thimble and the detector probably have some variation from thimble to thimble.

The thimble length permits the detectors to reach the top of the core for mapping of core power. For this purpose, several detectors can be inserted simultaneously. Switching is provided outside of the reactor vessel so that all of the locations in the core can be mapped by measurements with several groups of thimbles.

Wear of the thimble wall due to vibration of the thimble has occurred. This wear is monitored by eddy current inspection. In some cases, the noise signals of in-core detectors can be used to detect thimble vibration as discussed below.

B-1.2 Detection of Thimble Vibration Using In-Core Detector Neutron Noise

Vibration of the thimble and detector causes the detector to move through a flux gradient. If the thimble vibration mode includes motion at fuel elevations, motion can be detected by acquisition and analysis of in-core neutron noise signals using the same techniques as those that are used for detecting structural vibration from ex-core signals. Although a broad database is not available, this technique has been used to compare the vibration levels for thimbles fitted with various wear mitigation devices (Trenty, 1987). On this basis, the neutron noise method could be used to identify very active locations.

B-2 BAFFLE JETTING

B-2.1 Introduction

The primary flow path for "down flow" PWR internals is through the reactor coolant system (RCS) inlet nozzles, down the outside of the lower core support barrel (CSB) to the bottom of the reactor vessel (RV), and up through the lower fuel assembly area. In addition to this, in some PWR designs, a secondary flow path is generated by holes through the CSB below the top former plate, connecting the main RCS flow at the bottom of the RV. Baffle plates exist in an annular region that is a transition region between the outer fuel assembly pattern and the round CSB. Because of the pressure drop of the main RCS channel through the core, a differential pressure exists between the core region and the region made up of the core support barrel/baffle plates. Because of the small gaps that exist in the joints between the individual baffle plates, the differential pressure causes a jet of water to flow horizontally into the core region. If the gap and the jet are sufficiently large, this jet of water is known as "baffle jetting" and can cause the outer fuel pins to vibrate excessively.

B-2.2 Data Acquisition

Signals monitored must include the signals from a "prompt in-core detector" in the fuel assembly suspected of baffle jetting.

The in-core detector elevation should be in the upper half of the fuel assembly suspected of baffle jetting. The data acquired should include the in-core signals from an interior fuel assembly, preferably several interior and peripheral in-core signals simultaneously.

The data acquired must also include the ex-core neutron detector in the quadrant of suspected baffle jetting and should include all ex-core upper and lower chambers, preferably all ex-core upper and lower chambers simultaneously with the in-core detectors.

Because of electrical noises inherent in power plant signals, both in-core and ex-core signals need to be filtered prior to acquisition (see Table 1 of this Part). The frequency set points for the filters during data acquisition should not interfere with the frequency range of interest. See section 5 for more details.

B-2.3 Data Diagnosis

(a) Data reduction should include the generation of the following functions:

(1) power spectral density (PSD)
(2) cross-power spectral density (CPSD)
(3) coherence (COH)
(4) phase (PHA)

It is recommended that 100 blocks of data be averaged to reduce statistical uncertainties.

(b) The functions listed above should be generated for the following combinations of signals:

(1) The in-core signals from the upper half of fuel assemblies of interest and the ex-core upper section signals from the quadrant closest to the suspected baffle jetting should be correlated and compared.

(2) The in-core signals from an interior fuel assembly and the in-core signals of the fuel assembly in which baffle jetting is suspected.

B-3 FUEL ASSEMBLY VIBRATIONS

B-3.1 Introduction

A PWR fuel assembly exists in an environment where flowing water conditions passing through the fuel assembly cause the fuel assembly to vibrate. In-core detector signals can provide information on this vibration.

B-3.2 Data Acquisition

In-core detector data should be acquired at several axial locations in the fuel assemblies of direct interest and in several reference assemblies.

If permitted by the detector configuration, data from several axial levels should be acquired simultaneously within the same assembly, as well as from the reference assemblies.

As a minimum, simultaneous recording of the center in-core signal and the signal of the detector closest to each ex-core detector should be recorded. Ex-core detector signals in the quadrants of the fuel assemblies of interest should be acquired with at least a selected sample of the in-core signals.

B-3.3 Data Diagnosis

Data analysis and interpretation should be done in accordance with para. B-2.3. For detection of fuel assembly vibration modes, the expected mode shapes and natural frequencies should be available during data acquisition and diagnostic phases.

Industry experience has shown that the lower elevation in-core signals and lower section ex-core signals are influenced more strongly by the primary beam mode vibration of the core support barrel. Upper elevation in-core signals and the upper section ex-core signals will more readily show the fuel assembly modes. If in-core detector data from several elevations cannot be acquired simultaneously, the relative amplitudes of a frequency peak or rms level over a frequency range from data acquired at different times can be compared to the expected relative amplitude of the fuel assembly mode expected near that frequency to support interpretation.

B-4 REFERENCE

The following publication is referenced in this Nonmandatory Appendix:

Trenty, A., et al., 1987, "Thimble Vibration Analysis and Monitoring on 1300 and 900 MW Reactors Using Accelerometers and Incore Neutron Noise," Progress in Nuclear Energy, Vol. 21, Proceedings of the Fifth Specialists Meeting on Reactor Noise, Munich, F.R.G., 12–16.

Part 23, Nonmandatory Appendix C
Pump-Induced Vibrations

C-1 INTRODUCTION

Occasionally ex-core neutron noise signals contain information generated by reactor coolant pump behavior. An understanding of how reactor coolant pumps can influence ex-core signals is required to properly interpret the ex-core neutron noise data and may assist the detection of pump anomalies. The purpose of this Nonmandatory Appendix is to present sample traces that demonstrate this process.

C-2 CASE STUDY 1: COOLANT PUMP OPERATION CHARACTERISTICS

(a) The plan view of a two-loop PWR plant and the relative location of its ex-core neutron noise detectors is shown in Fig. C-1. A baseline set of ex-core data (data set 1) was acquired during a fuel cycle for the three pairs of cross-core detectors: A-D, B-C, and X-Y. The results of the data analysis for each pair of cross-core detectors include normalized spectral densities (NPSD), normalized cross-NPSDs (NCPSD), phase-separated NCPSDs, coherence (COH), and phase (PHA). Figure C-2 shows a representative out-of-phase (180 deg) NCPSD. The reactor coolant pump rotor speed is clearly indicated by a narrow banded peak at 15 Hz.

Later during the same fuel cycle a similar set of ex-core data (data set 2) was acquired and reduced. Comparison of data sets 1 and 2 indicates the following:

(1) A narrow-banded, out-of-phase peak at 5.2 Hz appeared in the A-D and B-C cross-core detector data of data set 2 (see Fig. C-3).

(2) A similar peak did not appear in the X-Y data (see Fig. C-4).

(3) At other frequencies, the data was consistent except for amplitude differences arising from burn-up–related effects.

At the same time that the 5.2 Hz peak was observed, the loose-part monitoring (LPM) triaxial accelerometers mounted on top of reactor coolant pump 2A (see Fig. C-1) measured a predominant increased response at 5.2 Hz. The increased pump excitation was due to oil whip, a self-excited vibration, in the pump bearing. Mitchell (1993) discusses the causes and symptoms of oil whip, which causes vibration at frequencies less than half the rotor speed, when there is a critical speed below half the rotor speed. Since the rotor speed is 15 Hz, and a dominant structural natural frequency of the pump was calculated to be 5.2 Hz, oil whip should occur at 5.2 Hz.

Therefore, oil whip excited the pump giving rise to the increased acceleration levels measured and the unusual signals in the ex-core data.

Figure C-2 shows the typical out-of-phase peak of the pump rotor speed that appears in all cross ex-core detector data. In Fig. C-3, out-of-phase NCPSDs from data set 2 for detector pairs A-D and B-C are shown. A comparison of the rotor speed (15 Hz) peak with the 5.2-Hz peak show them both to be narrowband.

Fluid-borne and mechanical excitation originating at pump 2A excites the CSB asymmetrically. Asymmetric excitation produces lateral motion in the CSB that is dominant in one transverse direction. The 5.2-Hz peak appears in the out-of-phase NCPSD of detector pairs A-D and B-C and does not appear in the X-Y detector pair (compare Fig. C-3 with Fig. C-4) The fact that cross-core detector pairs A-D and B-C exhibit the 5.2-Hz peak, whereas detector pair X-Y does not, tends to corroborate the CSB lateral motion due to pump 2A.

During the next outage, pump 2A was replaced. A succeeding set of ex-core data was acquired and reduced. The NCPSDs of detector pairs A-D and B-C indicated the 5.2-Hz peak had been eliminated. In addition, the LPM accelerometer readings returned to nominal levels.

(b) This case study demonstrates the following:

(1) Characteristics of neutron signatures can be related to specific physical phenomena such as a change in pump operating conditions.

(2) Natural frequencies of plant structures, as determined from analyses and/or test data, e.g., the pump, provide necessary information to interpret the neutron noise signature.

(3) Correlating neutron noise data with LPM data provides supplemental information to enhance data evaluation of both monitoring system.

C-3 CASE STUDY 2: SPACE-TIME BEATING OF COOLANT PUMPS IN A MULTI-LOOP PWR PLANT

A typical PWR plant consists of two to four loops, each loop driven by a coolant pump. Because the design and loading of these pumps are very similar, they run at very nearly the same speeds. As the impeller rotates, it generates acoustic pressure waves at the blade passing frequency and its higher harmonics. Thus, a coolant pump with a five-blade impeller rotating at 1,200 rpm will generate acoustic waves at frequencies of 100, 200, 300 (and so on) Hz as well as at the fundamental shaft rotation frequency of 20 Hz. These acoustic waves propagate along the coolant conduits into the reactor vessel internals and induce pressure on the core support barrel or thermal shield. Under idealized conditions when the impeller rotational speeds are identical, the phase relationship of the acoustic pressure induced by the coolant pumps in the different loops will be constant, and the reactor core will be biased to one side by the resultant force. In the actual situation the pumps rotate at minutely different speeds. As a result, the acoustic waves generated by the different coolant pumps are minutely different in frequencies. This gives rise to multi-pump beating very much like the sound generated by a multi-engine, propeller-driven airplane. The alternate constructive and destructive interference of the acoustic pressure waves gives rise to a changing net lateral force acting on the reactor core support barrel or thermal shield. Since this net force not only changes in magnitude, but also in direction, with time, the resultant core motion is not only vibratory but also precessional.

This phenomenon was analytically predicted by Au-Yang (1979) and was observed in actual neutron noise data. Figure C-5, reproduced from Wach and Sunder (1977), shows the precessional motion of the core of a reactor in a multi-loop PWR plant in Europe. Under normal conditions, the vibratory amplitudes are very small and will not cause any fatigue damage to the internal components.

C-4 REFERENCES

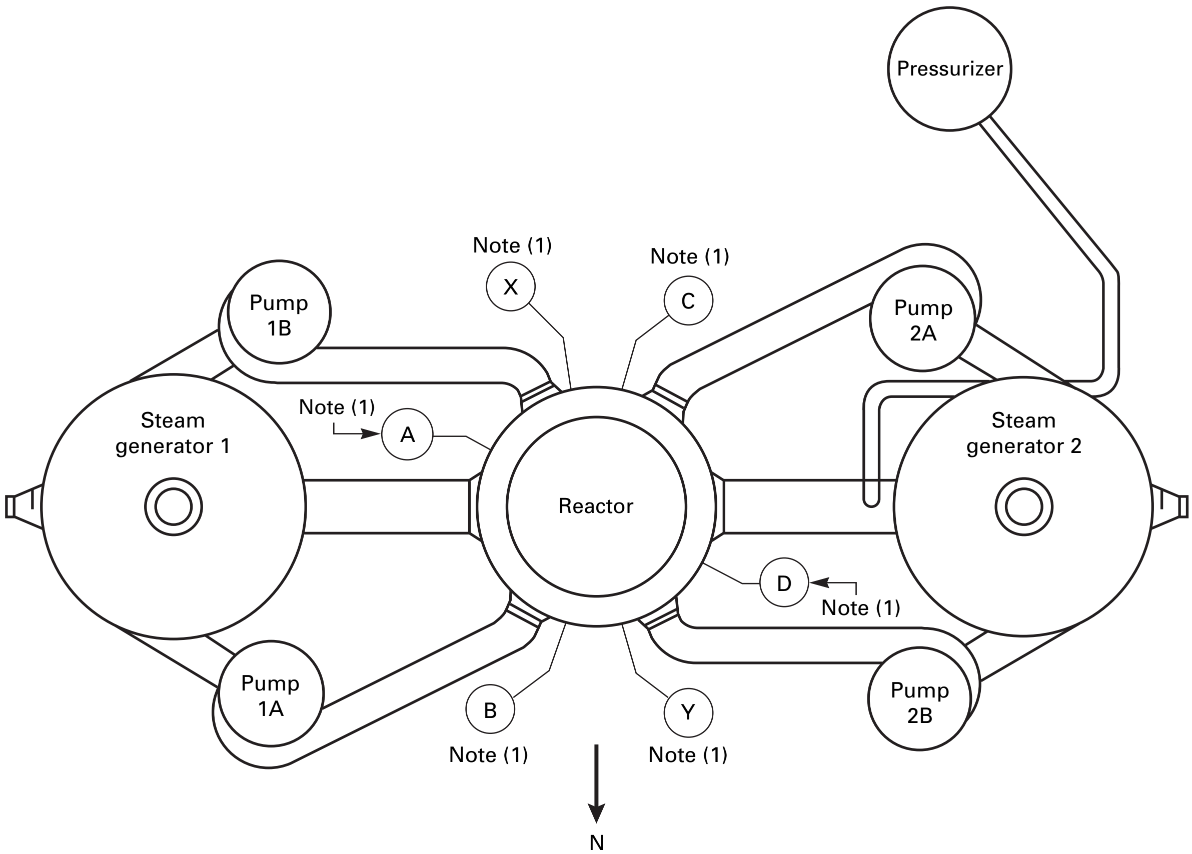
The following is a list of publications referenced in this Appendix:

Au-Yang, M. K., 1979, "Pump-Induced Acoustic Pressure Distribution in an Annular Cavity Bounded by Rigid Walls," Journal of Sound and Vibration, Vol. 62, pp. 577–591

Mitchell, J. S., 1993, "Machinery Analysis and Monitoring Second Edition," p. 176, PennWell Books

Wach, D. and Sunder, R., 1977, "Improved PWR Neutron Noise Interpretation Based on Detailed Vibration Analysis," paper presented at the Second Specialists' Meeting on Reactor Noise, Gatlinburg, Tennessee

Fig. C-1 Reactor Coolant System Arrangement — Plan View



GENERAL NOTE: See section C-2.

NOTE:

(1) Ex-core detector location.

Fig. C-2 Data Set I, 180 deg Phase NCPSD, A–D

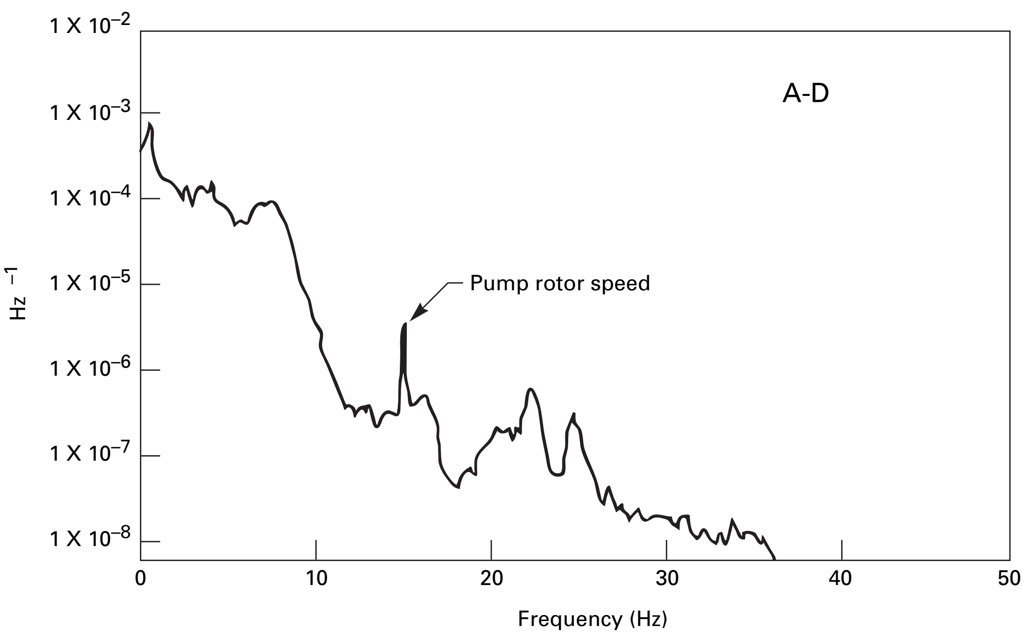
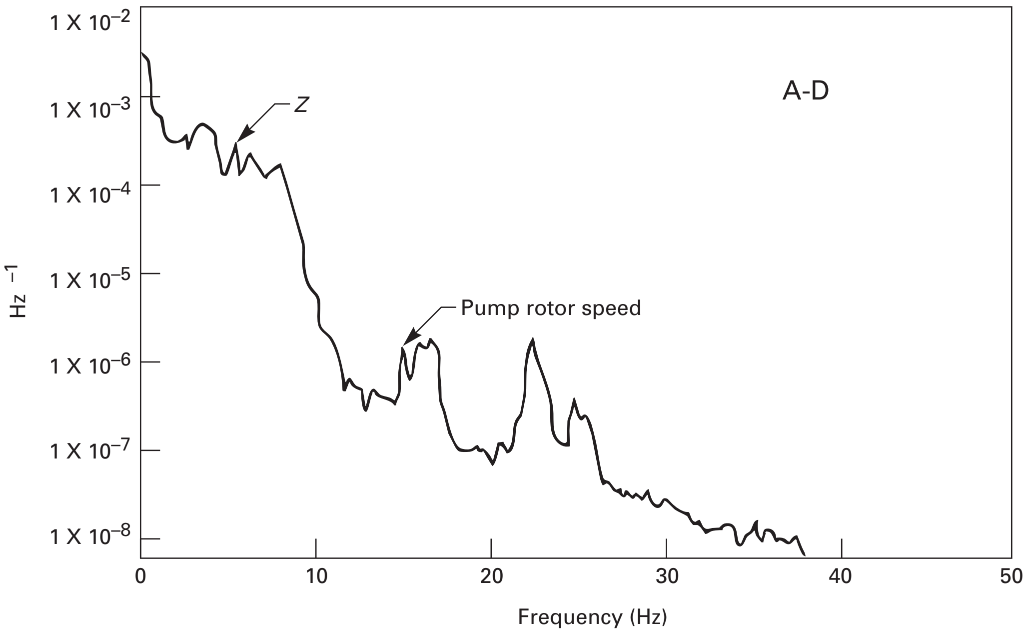
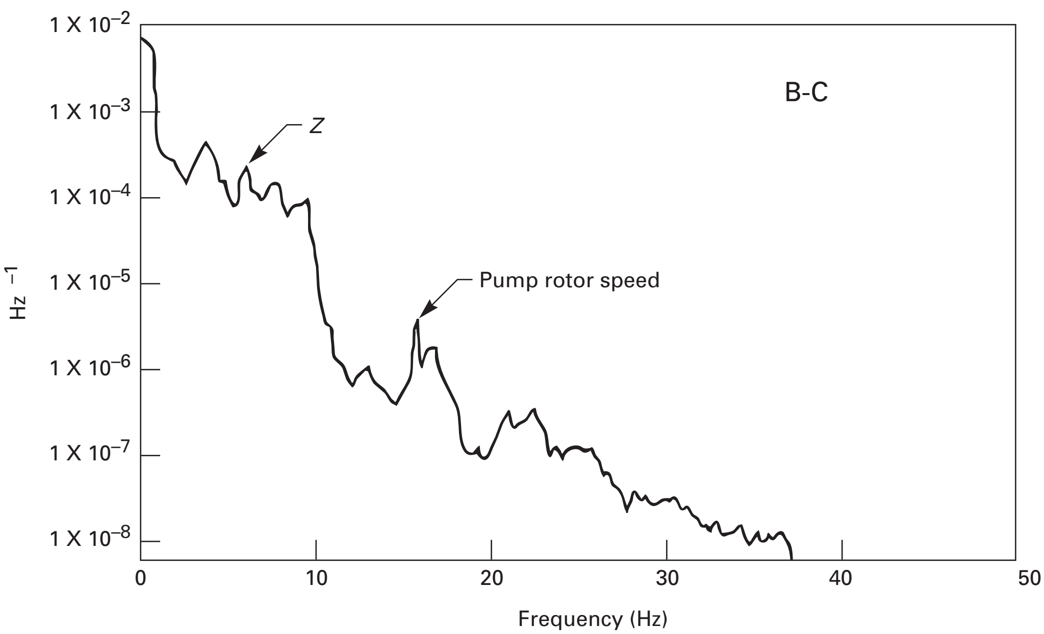


Fig. C-3 Data Set II, 180 deg NCPSD, A–D and B–C



(a) A-D Cross-Core Detector Data



(b) B-C Cross-Core Detector Data

Fig. C-4 180 deg Phase NCPSD, X–Y

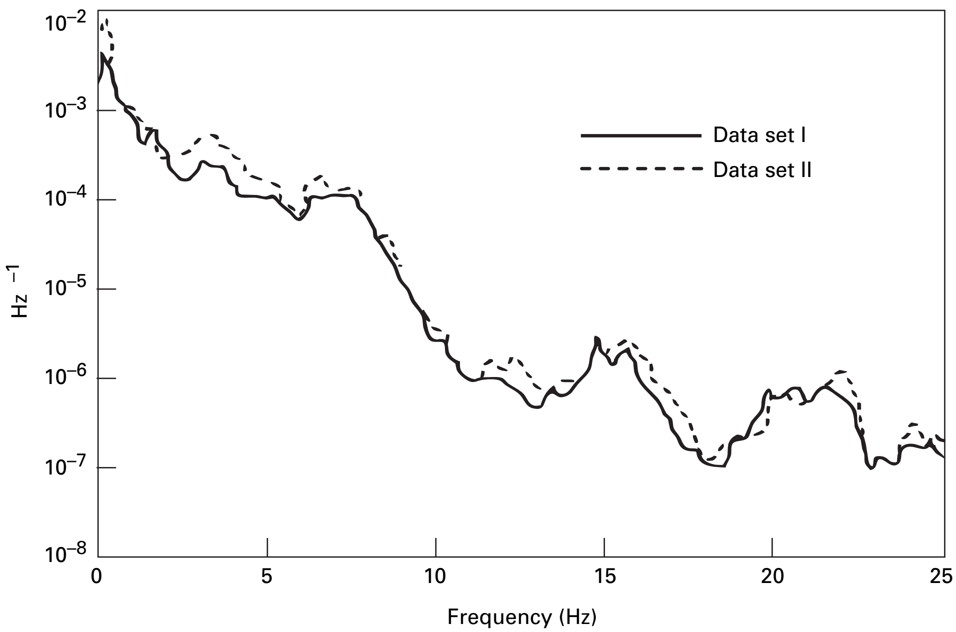
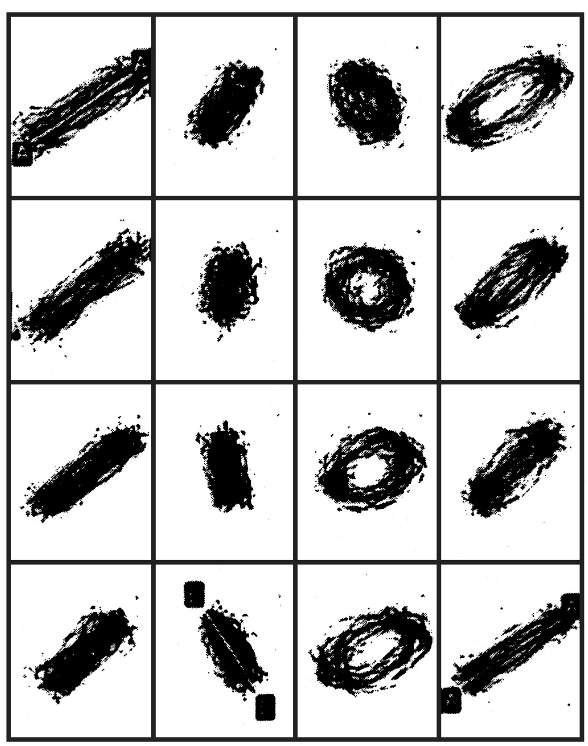


Fig. C-5 Lissajous Figure of Ex-Core Neutron Noise Data Showing Motion of Reactor Core in a Multi-Loop Plant



GENERAL NOTE: See section C-3.

Part 23, Nonmandatory Appendix D Sampling Rate and Length of Data Record Requirement to Resolve a Spectral Peak

One of the needs from a stored time history that has been recorded digitally could be resolution of a spectral peak. This could be needed to ascertain the bandwidth of the peak so that, for example, the apparent damping of a structural model could be estimated.

An example, using a peak intended to be narrow, is given as follows:

(a) expected natural frequency: 10 Hz
(b) expected damping ratio: 0.005
(c) required accuracy in damping ratio: 20%
(d) required statistical accuracy: 100 averages

Question: What should be the sampling rate? How long a time record is needed?

Solution: Damping ratio is related to the half-power width of the resonance peak by the relationship,

$$\zeta = \delta f/2f_o$$

where

f_o = natural frequency
δf = bandwidth at half power

there is

$$\delta f = 2f_o\mathbf{s} = 2 \times 0.005 = 0.1 \text{ Hz}$$

To determine the damping ratio within an accuracy of 20%, we need a frequency resolution of

$$\Delta f = 0.02 \text{ Hz}$$

This will give 10 points to represent this peak. Application of the Nyquist sampling theorem to the 10 Hz expected natural frequency indicates the required minimum sampling rate for the waveform is 20 samples/sec. In practice some margin is necessary. As an example, the following sampling rate is selected:

$$f_s = 30/\text{sec}$$

By comparison, the compact disc format uses a sampling rate of 44,100/sec to ensure reproduction of musical notes up to 20,000 Hz. So here we have more margin than the CD. The sampling time interval ΔT is the inverse of the sampling frequency. Thus,

$$\Delta T = 1/f_s = 1/30 \text{ sec}$$

Most waveform and frequency analyzers use the Fast Fourier Transform (FFT) algorithm, for which the number of data points to be transformed each time must be 2^k where k is an integer. As an example, with a block size of

$$n = 2^{10} = 1{,}024 \text{ points}$$

The length of time record per block is

$$\delta T = n\Delta T = 1{,}024 \times 1/30 = 34.13 \text{ sec}$$

After FFT, we get 512 points on the $+f$ side and 512 points on the $-f$ side of the spectral curve, which is symmetrical about $f = 0$. Only the $+f$ side is useful to us. The maximum frequency we get is called the Nyquist frequency, and is equal to one-half the sampling frequency (15 Hz in the present case), and we have 512 + 1 = 513 points to represent it. Thus, the frequency resolution is

$$\Delta f = 15/512 = 0.029 \text{ Hz}$$

and in general

$$\Delta f\,\Delta T = 1/n$$

Since 0.029 Hz is larger than what is required to adequately define the spectral peak, we have to increase the number of data points, n, per block. The next step up is to choose

$$n = 2^{11} = 2{,}048$$

Keeping the same sampling rate $\Delta T = 1/30$ sec, we have now after FFT

$$\Delta f = 1/(n\Delta T) = 1\ /\ (2{,}048 \times 1/30) = 0.0146 \text{ Hz}$$

This is fine to define the resonance peak, as originally determined. But the time record per block is now

$$\delta T = 2{,}048 \times 1/30 \text{ sec}$$

and we need 100 blocks of this to achieve the required statistical accuracy. The total length of time record we need is

$$T = Nn\Delta T = 100 \times 2{,}048/30 = 6{,}827 \text{ sec} = 1.9 \text{ hr}$$

If we use 12-bit words (this will give us a dynamic range of 72 dB), the total number of bits per channel of data per test record is

$$204{,}800 \times 12 = 2.46 \text{ M bit} = 1.23 \text{ M byte}$$

Most ex-core neutron noise detector system have between four to six sensors, bringing the total number of bytes per test record between 5 M to 10 M. This is still within the capability of modern digital acquisition equipment.

The above example shows that low-frequency tests involve very long time records. One way to economize is to sacrifice statistical accuracy. One hundred averages correspond to a normalized error of 0.1. In practice, more than 100 averages would not significantly enhance the accuracy. Since normalized error is

$$\epsilon = 1/\sqrt{N}$$

the number of averages can be dropped to 64 without sacrificing a lot of statistical accuracy while cutting the test time by 40%.

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ASME OM INTERPRETATIONS
(FOR DIVISION 1)

Replies to Technical Inquiries
February 12, 2013

FOREWORD

This publication includes all of the written replies issued on the indicated date by the Secretary, speaking for the ASME Committee on Operation and Maintenance of Nuclear Power Plants, to inquiries concerning interpretations of technical aspects of the ASME OM Code.

These replies are taken verbatim from the original letters, except for a few typographical corrections and some minor editorial corrections made for the purpose of improved clarity.

These interpretations were prepared in accordance with the accredited ASME procedures. ASME procedures provide for reconsideration of these interpretations when or if additional information is available which the inquirer believes might affect the interpretation. Further, persons aggrieved by an interpretation may appeal to the cognizant ASME Committee or Subcommittee. ASME does not “approve,” “certify,” “rate,” or “endorse” any item, construction, proprietary device, or activity.

An interpretation applies to the edition or addenda stated in the interpretation itself, or, if none is stated, to the latest published edition at the time it is issued. Subsequent revisions to the rules may have superseded the reply.

For detailed instructions on the preparation of technical inquiries, refer to Preparation of Technical Inquiries to the Committee on Operation and Maintenance of Nuclear Power Plants (p. v of ASME OM-2015).

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Interpretation: 15-01

Subject: ISTA-1100 and ISTC-1200 (1998 Edition Through 2009 Edition)

Date Issued: February 12, 2013

File: 10-1979

Question (1): Is it a requirement of para. ISTA-1100 that the term "specific function" used in subpara. ISTA-1100(a) is only made in reference to valves that have "active" function(s) as defined by para. ISTA-2000?

Reply (1): No.

Question (2): Is it a requirement of para. ISTC-1200 that a valve that is found to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident, in a passive manner cannot be excluded from the requirements of Subsection ISTC?

Reply (2): Yes.

Question (3): Is it a requirement of para. ISTC-1200 that the statement, "The following are excluded from this Subsection, provided that the valves are not required to perform a specific function as described in para. ISTA-1100," only applies to subparagraphs ISTC-1200(a), ISTC-1200(b), and ISTC-1200(c)?

Reply (3): Yes.

Question (4): Is it a requirement of paras. ISTA-1100, ISTC-1200, and ISTC-1300 that a valve that performs a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident, in a passive manner be categorized per para. ISTC-1300 as either "Category A, passive" or "Category B, passive" and then be subject to the applicable inservice test requirements of Table ISTC-3500-1?

Reply (4): Yes.

Question (5): Is it a requirement of para. ISTC-3700 and Table ISTC-3500-1 that a valve that performs a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident, in a passive manner, equipped with functioning/operable remote position indicators, be subject to the requirements of para. ISTC-3700 as stipulated by Table ISTC-3500-1?

Reply (5): Yes.

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OM CODE CASES (FOR DIVISION 1)

A Code Case is the official method of handling a reply to an inquiry when study indicates that the Code wording needs clarification, or when the reply modifies the existing requirements of the Code, or grants permission to use alternative methods.

ASME has agreed to publish Cases issued by the Operation and Maintenance Committee concerning the OM Code. Code Cases remain in effect for the applicable editions and addenda until they are annulled. Cases are published on the ASME Web site under the OM Committee Page at go.asme.org/OMcommittee as they are issued.

In July 2006, the Committee approved the elimination of Code Case expiration dates. Any published Code Case that has not been annulled and that had an expiration date that is after July 2006 is not expired and may continue to be used. The following Code Cases (with simplified/ shortened titles) remain in effect and are being published without expiration dates. The latest edition of each Code Case is listed. All previous revisions are included before the latest revision.

OMN-1, Revision 1	MOVs
OMN-3	Safety Significance Categorization Using Risk Insights
OMN-4	Risk Insights — Check Valves
OMN-6	Digital Instruments
OMN-7	Risk Insights — Pump Testing
OMN-8	Control Valves
OMN-9	Pump Curve Testing
OMN-10	Safety Significance Testing of Snubbers
OMN-11	Risk Insights — MOVs
OMN-12	Risk Insights — Pneumatically/Hydraulically Operated Valves
OMN-13, Revision 2	Extending Snubber Visual Examinations
OMN-15, Revision 2	Extending Snubber Operational Readiness Testing
OMN-16, Revision 1	Use of a Pump Curve for Testing
OMN-17	Alternative Rules — Class 1 Pressure/Safety Valves
OMN-18	Alternate Rules — Pumps Tested Within ±20% of Design Flow
OMN-19	Alternative Upper Limit for the Comprehensive Pump Test
OMN-20	Inservice Test Frequency
OMN-21	Alternative Requirements for Adjusting Hydraulic Parameters to Specified Reference Points

SUMMARY OF CHANGES

The Code Cases affected by this edition are as follows:

Page	*Code Case*	*Change*
C-48	OMN-13, Revision 2	In Table 1, right column head corrected by errata to read 2011
C-59	OMN-16	Fig. 1 added by errata
C-62	OMN-16, Revision 1	Fig. 1 added by errata

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Code Case OMN-1
Alternative Rules for Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants

Inquiry: What alternative rules, to those of OM Code, Subsection ISTC, may be used for preservice and inservice testing to assess the operational readiness of active electric motor-operated valve assemblies in light-water reactor power plants?

Reply: It is the opinion of the Committee that, in lieu of the rules for preservice and inservice testing to assess the operational readiness of active electric motor-operated valve assemblies in light-water reactor power plants in OM Code-1995, except for leakage rate testing, the following alternative requirements may be applied. Electric motor-operated valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their required function (Category A) must also be seat leakage rate tested in accordance with the requirements of the OM Code.

NOTE: The terms "shall consider" and "shall be considered" are used in paras. 3.6.2, 3.7.1, and 9.1 of this Code Case. The Code Case does not dictate how the considerations in the paragraphs are implemented or documented. Users of the Code Case will determine the best methods based on their programs, which may include procedures, checklists, training, or other methods.

1 INTRODUCTION

1.1 Scope

This Code Case establishes the requirements for preservice and inservice testing to assess the operational readiness of active motor-operated valves (MOVs) in light-water reactor (LWR) power plants.

The MOVs covered are those required to perform an active function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Code Case establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Exclusions

See para. ISTC-1200.

2 SUPPLEMENTAL DEFINITIONS

motor-operated valve (MOV): a valve and its associated electric motor-driven mechanism for positioning the valve, including components that control valve action and provide position output signals.

MOV functional margin: the increment by which an MOV's available capability exceeds the capability required to operate the MOV under design basis conditions.

stem factor: the ratio of stem torque to stem thrust in rising-stem valves.

full-cycle exercise: full stroke of the valve from and back to its initial position.

3 GENERAL REQUIREMENTS

3.1 Design Basis Verification Test

A one-time test shall be conducted to verify the capability of each MOV to meet its safety-related design basis requirements. This test shall be conducted at conditions as close to design basis conditions as practicable. Requirements for a design basis verification test are specified in applicable regulatory documents. Testing that meets the requirements of this Code Case but conducted before implementation of this Code Case may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.

(b) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an engineering analysis shall be documented that supports applicability to the in situ conditions.

(c) Justification for testing at conditions other than design basis conditions and for grouping like MOVs shall be documented by an engineering evaluation, alternate testing techniques, or both. Where design basis testing of the specific MOV being evaluated is impracticable, or not meaningful (provides no additional useful data), data from other MOVs may be used if justified by engineering evaluation. Sources for the data include other plant MOVs or test data published in industry testing programs. Where analytical techniques are used to verify design basis capability, those techniques shall be justified by an engineering evaluation.

(d) For certain valve types (e.g., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an

engineering evaluation of operating experience may be used to verify design basis capability.

(e) The design basis verification test shall be repeated if an MOV application is changed, the MOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an engineering evaluation, alternative testing techniques, or both.

3.2 Preservice Test

Each MOV shall be tested during the preservice test period or before implementing inservice testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Code Case but conducted before implementation of this Code Case may be used. Only one preservice test of each MOV is required unless, as described in para. 3.4, the MOV has undergone maintenance that could affect its performance.

3.3 Inservice Test

Inservice testing shall commence when the MOV is required to be operable to fulfill its required function(s), as described in para. 1.1, and shall be sufficient to assess changes in MOV functional margin consistent with section 6.

(a) MOVs may be grouped for inservice testing as described in para. 3.5.

(b) Inservice tests shall be conducted in the as-found condition. Activities shall not be conducted if they invalidate the inservice test results. If maintenance is needed between the inservice tests, see para. 3.4. As-found testing is not required prior to maintenance activities as long as the MOV is not due for an inservice test. If maintenance activities are scheduled concurrently with an MOV's inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity.

(c) The inservice testing program will include a mix of static and dynamic MOV performance testing. The mix of MOV performance testing may be altered when justified by an engineering evaluation of test data.

(d) Dynamic MOV performance testing is not required for certain valve types (e.g., ball, plug, and diaphragm valves), with acceptable operating experience.

(e) Remote position indication shall be verified locally during inservice testing or maintenance activities.

3.3.1 Inservice Test Interval

(a) The inservice test interval shall be determined in accordance with para. 6.4.4.

(b) If insufficient data exist to determine the inservice test interval in accordance with para. 6.4.4, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer test interval.

(c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per para. 3.4 may be used to satisfy this requirement.

3.4 Effect of MOV Replacement, Repair, or Maintenance

When an MOV or its control system is replaced, repaired, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined or the previously established inservice test values shall be confirmed before the MOV is returned to service. If the MOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required after replacement, repair, or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in section 9, Records and Reports.

3.5 Grouping of MOVs for Inservice Testing

Grouping MOVs for inservice testing is permissible. Grouping MOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping MOVs:

(a) MOVs with identical or similar motor operators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of MOVs shall be validated by appropriate inservice testing of one or more representative valves.

(b) Test results shall be evaluated and justified for all MOVs in the group.

3.6 MOV Exercising Requirements

3.6.1 Normal Exercising Requirements. All MOVs, within the scope of this Code Case, shall be full-cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 months. Full-cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full-stroke exercising of an MOV is not practical during plant operation or cold shutdown, full-stroke exercising shall be performed during the plant's refueling outage.

3.6.2 Additional Exercising Requirements. The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

(a) MOVs with high risk significance

(b) MOVs with adverse or harsh environmental conditions or

(c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

3.7 Risk-Informed MOV Inservice Testing

Risk-informed MOV inservice testing that incorporates risk insights in conjunction with performance margin to establish MOV grouping, acceptance criteria, exercising requirements, and testing interval may be implemented.

3.7.1 Risk-Informed Considerations. The Owner shall consider the following when incorporating risk insights in the inservice testing of MOVs:

(a) develop an acceptable risk basis for MOV risk determination

(b) develop MOV screening criteria to determine each MOV's contribution to risk

(c) finalize risk category by a documented evaluation from a plant expert panel

3.7.2 Risk-Informed Criteria. Each MOV shall be evaluated and categorized using a documented risk ranking methodology. This Code Case provides test requirements for High and Low Safety Significant Component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

3.7.2.1 HSSC MOVs. HSSC MOVs shall be tested in accordance with para. 3.3 and exercised in accordance with para. 3.6 of this Code Case. HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer exercise interval is small.

3.7.2.2 LSSC MOVs. In meeting the provisions of this Code Case, including exercising in accordance with para. 3.6 and the determination of proper MOV test interval in section 6, risk insights shall be applied to inservice testing of LSSC MOVs by the following:

(a) LSSC grouping shall be technically justified, but the provision for similarity in subpara. 3.5(a) may be relaxed. The provisions in subpara. 3.5(b) related to evaluation of test results for MOVs in that group continue to be applicable to all MOVs within the scope of this Code Case.

(b) LSSC MOVs may be associated with an established group of other MOVs. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with section 6 and applied to all LSSC MOVs associated with that group.

(c) LSSC MOVs that are not associated with an established group shall be inservice tested in accordance with para. 3.3 using an initial test interval of three refueling cycles or 5 yr (whichever is longer) until sufficient data exist to determine a more appropriate test interval as described in para. 6.4.4.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with para. 3.3.1.

4 TO BE PROVIDED AT A LATER DATE

5 TEST METHODS

5.1 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

5.2 Test Conditions

Inservice test conditions shall be sufficient to determine the MOV's functional margin per para. 6.4. Test conditions shall be recorded for each test per section 9.

5.3 Limits and Precautions

(a) MOV exposure to dust, moisture, or other adverse conditions shall be minimized when normally enclosed compartment covers are removed while performing tests.

(b) Manufacturer or vendor limits and precautions associated with the MOV and with the test equipment shall be considered, including the structural thrust and torque limits of the MOV.

(c) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(d) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the MOV by the particular testing performed.

5.4 Test Documents

Approved plant documents shall be established for all tests specified in this Code Case and shall provide for

(a) methodical, repeatable, and consistent performance testing

(b) collection of data required to analyze and evaluate the MOV functional margin in accordance with section 6

5.5 Test Parameters

Sufficient test parameters shall be selected for measurement to meet the requirements of section 6 in determining the MOV functional margin.

6 ANALYSIS AND EVALUATION OF DATA

6.1 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each

MOV within the scope of this Code Case. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the valve-operating requirements. Thrust, torque, or other measured engineering parameters correlated to thrust or torque consistent with paras. 6.1 through 6.5 may be used to establish the acceptance criteria. Motor control center testing is acceptable if correlation with testing at the MOV has been established. When determining the acceptance criteria, consider the following sources of uncertainty:

(a) test measurement and equipment accuracy

(b) valve and actuator repeatability (e.g., torque switch repeatability)

(c) analysis, evaluation, and extrapolation method

(d) grouping method

6.1.1 MOV margins may be expressed in terms of stem force or other parameters, if those parameters are consistent with paras. 6.1 through 6.5.

6.2 Analysis of Data

Data obtained from a test required by this Code Case shall be analyzed to determine if the MOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each MOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per para. 6.4.3, does not meet the acceptance criteria, the MOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

6.3 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each MOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating MOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable MOVs to establish appropriate time intervals for future test activities.

6.4 Determination of MOV Functional Margin

The Owner shall demonstrate that adequate margin exists between valve-operating requirements and the available actuator output capability to satisfy the acceptance criteria for MOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in MOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity. Refer to Figs. 6.4-1 through 6.4-4.

6.4.1 Determination of Valve-Operating Requirements. Design basis valve-operating requirements, including stem factor for rising-stem valves, shall be determined from

(a) measurements taken during testing at design basis conditions

(b) analytical methods using valve parameters determined from testing at conditions that may be extrapolated to design basis conditions

(c) application of justified industry methodologies

6.4.2 Determination of Actuator Output Capacity

6.4.2.1 Available Output Based on Motor Capabilities. Available actuator output shall be determined based on motor capabilities at the motor's design basis conditions. Considerations shall include

(a) rated motor start torque

(b) minimun voltage conditions

(c) elevated ambient temperature conditions

(d) operator efficiency

(e) other appropriate factors

6.4.2.2 Available Output Based on Torque Switch Setting. Where applicable, the available output shall be determined based on the current torque switch setting.

For MOVs where inservice testing does not sufficiently load the MOV to cause torque switch trip (e.g., butterfly and ball valves), available output based on the current torque switch setting shall be determined analytically from test data. Considerations shall include

(a) calibration of the torque switch spring pack

(b) the current torque switch setting

(c) repeatability of torque switch operation

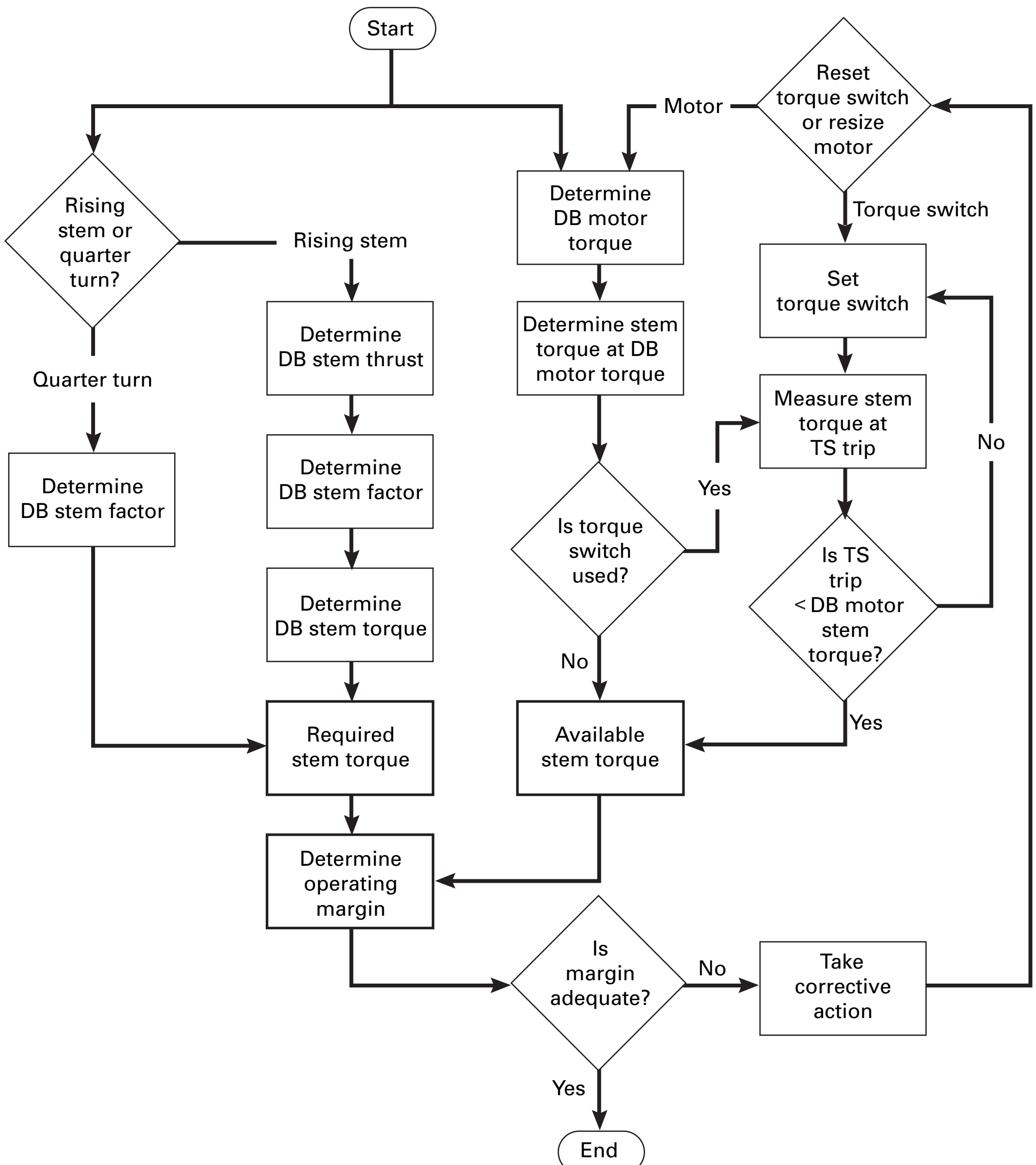
6.4.3 Calculation of MOV Functional Margin. MOV functional margin shall be calculated as the difference between the available actuator output and valve-operating requirements. Available actuator output is determined as

(a) design basis motor operator capability for limit switch-controlled strokes or

(b) the lesser of design basis motor operator capability or motor operator capability at the current torque switch setting for torque switch-controlled strokes

6.4.4 Determination of MOV Test Interval. Calculations for determining MOV functional margin shall account for potential performance-related degradation. Maintenance activities and associated intervals can

Fig. 6.4-1 MOV Functional Margin Determination Flowchart



LEGEND:
DB = design basis
TS = torque switch

Fig. 6.4-2 Determining Functional Margin for Rising-Stem MOVs

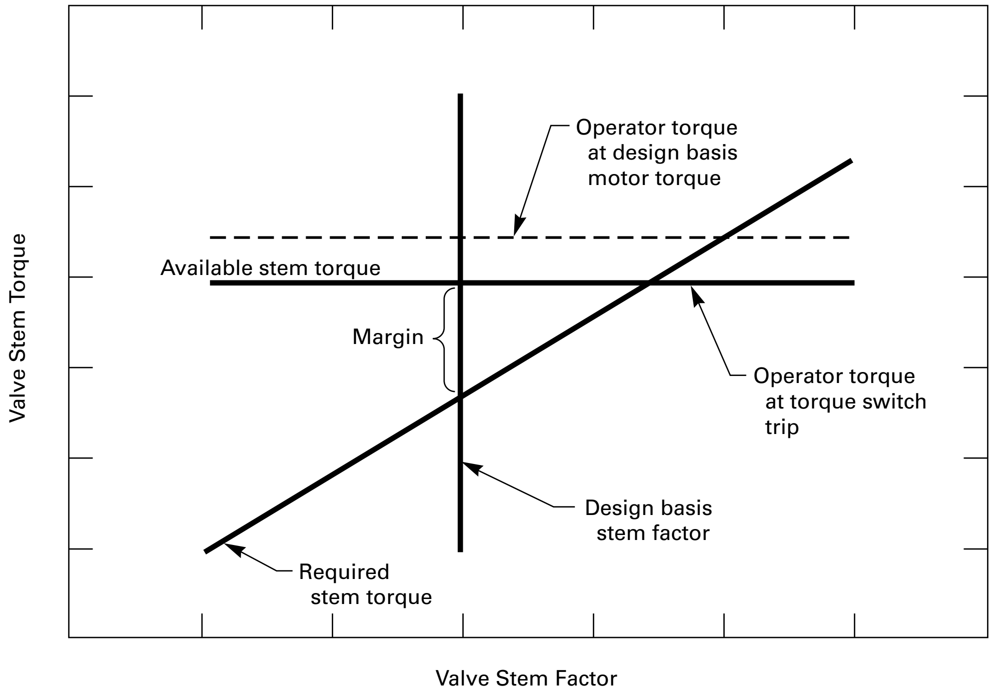


Fig. 6.4-3 Decrease in Functional Margin Over Time for Rising-Stem MOVs

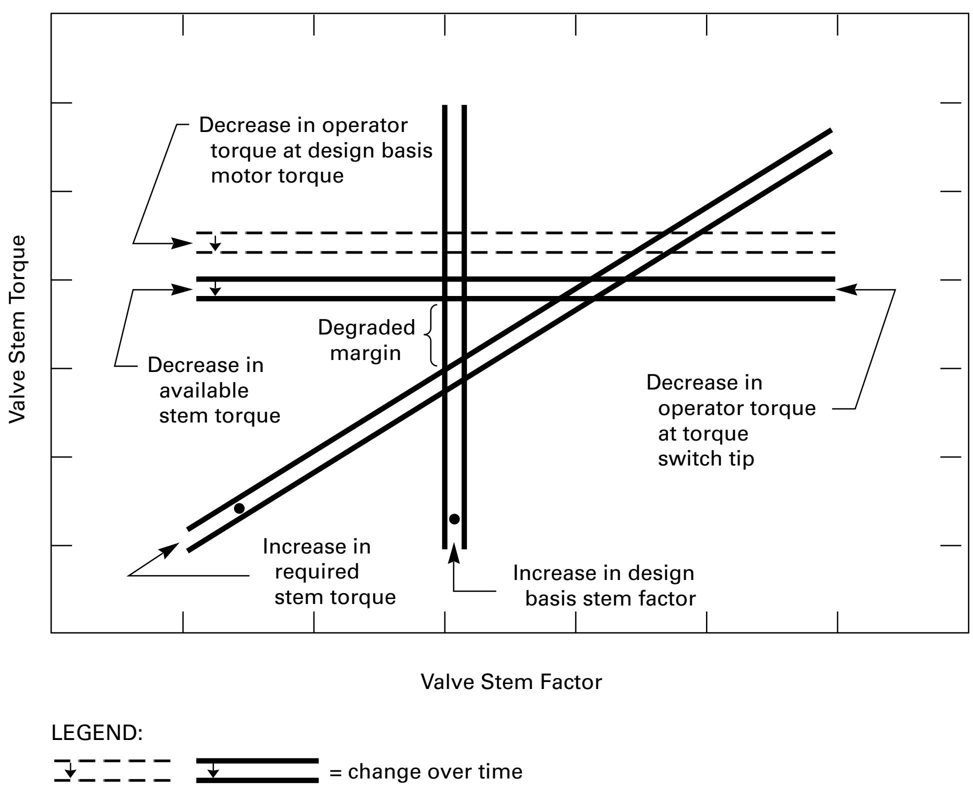
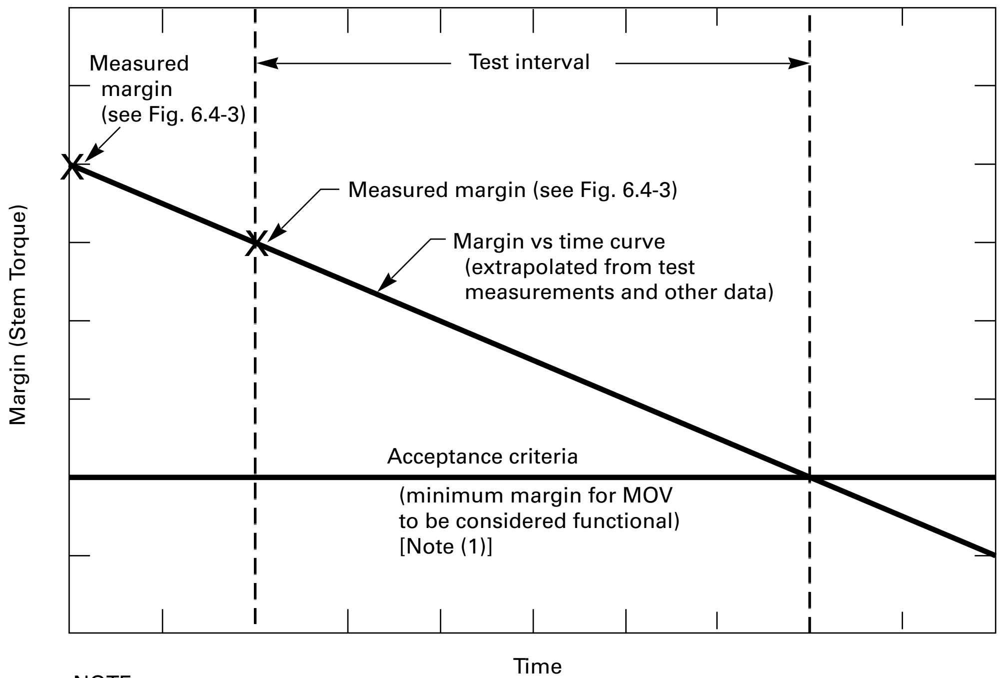


Fig. 6.4-4 Determining the Test Intervals for Maintaining MOV Functional Margin



NOTE:
(1) Calculated value plus uncertainty.

affect test intervals and shall be considered. The inservice test interval shall be set such that the MOV functional margin does not decrease below the acceptance criteria.

6.5 Corrective Action

If the MOV performance is unacceptable, as established in para. 6.4, corrective action shall be taken in accordance with Owner's corrective action requirements.

6.5.1 Record of Corrective Action. The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent inservice tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.

7 TO BE PROVIDED AT A LATER DATE

8 TO BE PROVIDED AT A LATER DATE

9 RECORDS AND REPORTS

9.1 Test Information

Pertinent test information shall be recorded or verified for MOV testing, described in section 3. The following information shall be considered:

(a) MOV plant-specific unique identification number.

(b) motor, valve, actuator nameplate data.

(c) test equipment unique identification numbers and equipment calibration dates.

(d) test method and conditions, described in section 5, including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, electric motor-operator orientation, and piping configuration near the MOV.

(e) breaker setting/fuse size and motor starter thermal overload size, if used.

(f) MOV torque and limit switch configuration and settings.

(g) MOV performance test procedure and other approved plant documents containing acceptance criteria.

(h) name of test performer and date of test.

(i) system flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.

(j) significant observations — any comments pertinent to the test results that otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic MOV action noted either during or preceding performance testing and any other pertinent design information that can be verified at the MOV.

9.2 Documentation of Analysis and Evaluation of Data

The documentation of acceptable MOV performance, which has been analyzed and evaluated in accordance with section 6, shall include, as a minimum

(a) values of test data, test parameters, and test information established by paras. 5.5 and 9.1.

(b) summary of analysis and evaluation required per paras. 6.2 and 6.3.

(c) statement(s), by an individual qualified to make such a statement through the Owner's qualification requirements, confirming that the MOV is capable of performing its intended safety function.

(d) test results and analysis shall be evaluated by qualified individuals and documented to include signature and date. Independent verification shall be by individuals qualified to verify those specific analyses and evaluations through the Owner's qualification requirements.

Code Case OMN-1, Revision 1
Alternative Rules for Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants

Inquiry: What alternative rules, to those of OM Code, Subsection ISTC, may be used for preservice and inservice testing to assess the operational readiness of active electric motor-operated valve assemblies in light water reactor power plants?

Reply: It is the opinion of the Committee that, in lieu of the rules for preservice and inservice testing to assess the operational readiness of active electric motor-operated valve assemblies in light water reactor power plants in the OM Code-1995, except for leakage rate testing, the following alternative requirements may be applied. Electric motor-operated valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their required function (Category A) must also be seat leakage rate tested in accordance with the requirements of the OM Code.

NOTE: The terms "shall consider" and "shall be considered" are used in paras. 3.6.2, 3.7.1, and 9.1 of this Code Case. The Code Case does not dictate how the considerations in the paragraphs are implemented or documented. Users of the Code Case will determine the best methods based on their programs, which may include procedures, checklists, training, or other methods.

1 INTRODUCTION

1.1 Scope

This Code Case establishes the requirements for preservice and inservice testing to assess the operational readiness of active motor-operated valves (MOVs) in light water reactor (LWR) power plants.

The MOVs covered are those required to perform an active function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This Code Case establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Exclusions

See para. ISTC-1200.

2 SUPPLEMENTAL DEFINITIONS

full cycle exercise: full stroke of the valve from and back to its initial position.

motor-operated valve (MOV): a valve and its associated electric motor driven mechanism for positioning the valve, including components that control valve action and provide position output signals.

MOV functional margin: the increment by which an MOV's available capability exceeds the capability required to operate the MOV under design basis conditions.

stem factor: the ratio of stem torque to stem thrust in rising-stem valves.

3 GENERAL REQUIREMENTS

3.1 Design Basis Verification Test

A one-time test shall be conducted to verify the capability of each MOV to meet its safety-related design basis requirements. This test shall be conducted at conditions as close to design basis conditions as practicable. Requirements for a design basis verification test are specified in applicable regulatory documents. Testing that meets the requirements of this Code Case but conducted before implementation of this Code Case may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.

(b) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an engineering analysis shall be documented that supports applicability to the in situ conditions.

(c) Justification for testing at conditions other than design basis conditions and for grouping like MOVs shall be documented by an engineering evaluation, alternate testing techniques, or both. Where design basis testing of the specific MOV being evaluated is impracticable, or not meaningful (provides no additional useful data), data from other MOVs may be used if justified by engineering evaluation. Sources for the data include other plant MOVs or test data published in industry testing programs. Where analytical techniques are used

to verify design basis capability, those techniques shall be justified by an engineering evaluation.

(d) For certain valve types (e.g., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an engineering evaluation of operating experience may be used to verify design basis capability.

(e) The design basis verification test shall be repeated if an MOV application is changed, the MOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an engineering evaluation, alternative testing techniques, or both.

3.2 Preservice Test

Each MOV shall be tested during the preservice test period or before implementing inservice testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Code Case but conducted before implementation of this Code Case may be used. Only one preservice test of each MOV is required unless, as described in para. 3.4, the MOV has undergone maintenance that could affect its performance.

3.3 Inservice Test

Inservice testing shall commence when the MOV is required to be operable to fulfill its required function(s), as described in para. 1.1, and shall be sufficient to assess changes in MOV functional margin consistent with section 6.

(a) MOVs may be grouped for inservice testing as described in para. 3.5.

(b) Inservice tests shall be conducted in the as-found condition. Activities shall not be conducted if they invalidate the inservice test results. If maintenance is needed between the inservice tests, see para. 3.4. As-found testing is not required prior to maintenance activities as long as the MOV is not due for an inservice test. If maintenance activities are scheduled concurrently with an MOV's inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity.

(c) The inservice testing program will include a mix of static and dynamic MOV performance testing. The mix of MOV performance testing may be altered when justified by an engineering evaluation of test data.

(d) Dynamic MOV performance testing is not required for certain valve types (e.g., ball, plug, and diaphragm valves), with acceptable operating experience.

(e) Remote position indication shall be verified locally during inservice testing or maintenance activities.

3.3.1 Inservice Test Interval

(a) The inservice test interval shall be determined in accordance with para. 6.4.4.

(b) If insufficient data exist to determine the inservice test interval in accordance with para. 6.4.4, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer inservice test interval.

(c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per para. 3.4 may be used to satisfy this requirement.

3.4 Effect of MOV Replacement, Repair, or Maintenance

When an MOV or its control system is replaced, repaired, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined, or the previously established inservice test values shall be confirmed before the MOV is returned to service. If the MOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required after replacement, repair, or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in section 9, Records and Reports.

3.5 Grouping of MOVs for Inservice Testing

Grouping MOVs for inservice testing is permissible. Grouping MOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping MOVs:

(a) MOVs with identical or similar motor-operators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of MOVs shall be validated by appropriate inservice testing of one or more representative valves.

(b) Test results shall be evaluated and justified for all MOVs in the group.

3.6 MOV Exercising Requirements

3.6.1 Normal Exercising Requirements. All MOVs, within the scope of this Code Case, shall be full cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 mo. Full cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full stroke exercising of an MOV is not practical during plant operation or cold shutdown, full stroke exercising shall be performed during the plant's refueling outage.

3.6.2 Additional Exercising Requirements. The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

(a) MOVs with high risk significance

(b) MOVs with adverse or harsh environmental conditions or

(c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

3.7 Risk-Informed MOV Inservice Testing

Risk-informed MOV inservice testing that incorporates risk insights in conjunction with performance margin to establish MOV grouping, acceptance criteria, exercising requirements, and testing interval may be implemented.

3.7.1 Risk-Informed Considerations. The Owner shall consider the following when incorporating risk insights in the inservice testing of MOVs:

(a) Develop an acceptable risk basis for MOV risk determination.

(b) Develop MOV screening criteria to determine each MOV's contribution to risk.

(c) Finalize risk category by a documented evaluation from a plant expert panel.

3.7.2 Risk-Informed Criteria. Each MOV shall be evaluated and categorized using a documented risk ranking methodology. This Code Case provides test requirements for high and low safety significant component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

3.7.2.1 HSSC MOVs. HSSC MOVs shall be tested in accordance with para. 3.3 of this Code Case and exercised in accordance with para. 3.6 of this Code Case. HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer exercise interval is small.

3.7.2.2 LSSC MOVs. In meeting the provisions of this Code Case, including exercising in accordance with para. 3.6 and the determination of proper MOV test interval in section 6, risk insights shall be applied to inservice testing of LSSC MOVs by the following:

(a) LSSC grouping shall be technically justified, but the provision for similarity in subpara. 3.5(a) may be relaxed. The provisions in subpara. 3.5(b) related to evaluation of test results for MOVs in that group continue to be applicable to all MOVs within the scope of this Code Case.

(b) LSSC MOVs may be associated with an established group of other MOVs. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with section 6, and applied to all LSSC MOVs associated with that group.

(c) LSSC MOVs that are not associated with an established group shall be inservice tested in accordance with para. 3.3 using an initial test interval of three refueling cycles or 5 yr (whichever is longer) until sufficient data exist to determine a more appropriate test interval as described in para. 6.4.4.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with para. 3.3.1.

4 TO BE PROVIDED AT A LATER DATE

5 TEST METHODS

5.1 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

5.2 Test Conditions

Inservice test conditions shall be sufficient to determine the MOV's functional margin per para. 6.4. Test conditions shall be recorded for each test per section 9.

5.3 Limits and Precautions

(a) MOV exposure to dust, moisture, or other adverse conditions shall be minimized when normally enclosed compartment covers are removed while performing tests.

(b) Manufacturer or vendor limits and precautions associated with the MOV and with the test equipment shall be considered, including the structural thrust and torque limits of the MOV.

(c) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(d) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the MOV by the particular testing performed.

5.4 Test Documents

Approved plant documents shall be established for all tests specified in this Code Case and shall provide for

(a) methodical, repeatable, and consistent performance testing

(b) collection of data required to analyze and evaluate the MOV functional margin in accordance with section 6

5.5 Test Parameters

Sufficient test parameters shall be selected for measurement to meet the requirements of section 6 in determining the MOV functional margin.

6 ANALYSIS AND EVALUATION OF DATA

6.1 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each MOV within the scope of this Code Case. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the valve operating requirements. Thrust, torque, or other measured engineering parameters correlated to thrust or torque consistent with paras. 6.1 through 6.5 may be used to establish the acceptance criteria. Motor control center testing is acceptable if correlation with testing at the MOV has been established. When determining the acceptance criteria, consider the following sources of uncertainty:

(a) test measurement and equipment accuracy

(b) valve and actuator repeatability (e.g., torque switch repeatability)

(c) analysis, evaluation, and extrapolation method

(d) grouping method

6.1.1 MOV margins may be expressed in terms of stem force or other parameters, if those parameters are consistent with paras. 6.1 through 6.5.

6.2 Analysis of Data

Data obtained from a test required by this Code Case shall be analyzed to determine if the MOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each MOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per para. 6.4.3, does not meet the acceptance criteria, the MOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

6.3 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each MOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating MOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable MOVs to establish appropriate time intervals for future test activities.

6.4 Determination of MOV Functional Margin

The Owner shall demonstrate that adequate margin exists between valve operating requirements and the available actuator output capability to satisfy the acceptance criteria for MOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in MOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

6.4.1 Determination of Valve Operating Requirements. Design basis valve operating requirements, including stem factor for rising stem valves, shall be determined from one of the following:

(a) measurements taken during testing at design basis conditions

(b) analytical methods using valve parameters determined from testing at conditions that may be extrapolated to design basis conditions or

(c) application of justified industry methodologies

6.4.2 Determination of Actuator Output Capability

6.4.2.1 Available Output Based on Motor Capabilities. Available actuator output shall be determined based on motor capabilities at the motor's design basis conditions. Considerations shall include

(a) rated motor start torque

(b) minimum voltage conditions

(c) elevated ambient temperature conditions

(d) operator efficiency

(e) other appropriate factors

6.4.2.2 Available Output Based on Torque Switch Setting. Where applicable, the available output shall be determined based on the current torque switch setting.

For MOVs where inservice testing does not sufficiently load the MOV to cause torque switch trip (e.g., butterfly and ball valves), available output based on the current torque switch setting shall be determined analytically from test data. Considerations shall include

(a) calibration of the torque switch spring pack

(b) the current torque switch setting

(c) repeatability of torque switch operation

6.4.3 Calculation of MOV Functional Margin. MOV functional margin shall be calculated as the difference between the available actuator output and valve operating requirements. Available actuator output is determined as either of the following:

(a) design basis motor operator capability for limit switch controlled strokes, or

(b) the lesser of design basis motor operator capability or motor operator capability at the current torque switch setting for torque switch controlled strokes

6.4.4 Determination of MOV Test Interval. Calculations for determining MOV functional margin shall account for potential performance-related degradation. Maintenance activities and associated intervals can affect test intervals and shall be considered. The inservice test interval shall be set such that the MOV functional margin does not decrease below the acceptance criteria.

6.5 Corrective Action

If the MOV performance is unacceptable, as established in para. 6.4, corrective action shall be taken in accordance with Owner's corrective action requirements.

6.5.1 Record of Corrective Action. The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent inservice tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.

7 TO BE PROVIDED AT A LATER DATE

8 TO BE PROVIDED AT A LATER DATE

9 RECORDS AND REPORTS

9.1 Test Information

Pertinent test information shall be recorded or verified for MOV testing, described in section 3. The following information shall be considered:

(a) MOV plant-specific unique identification number.

(b) motor, valve, actuator nameplate data.

(c) test equipment unique identification numbers and equipment calibration dates.

(d) test method and conditions, described in section 5, including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, electric motor-operator orientation, and piping configuration near the MOV.

(e) breaker setting/fuse size and motor starter thermal overload size, if used.

(f) MOV torque and limit switch configuration and settings.

(g) MOV performance test procedure and other approved plant documents containing acceptance criteria.

(h) name of test performer and date of test.

(i) system flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.

(j) significant observations: any comments pertinent to the test results that otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic MOV action noted either during or preceding performance testing and any other pertinent design information that can be verified at the MOV.

9.2 Documentation of Analysis and Evaluation of Data

The documentation of acceptable MOV performance, which has been analyzed and evaluated in accordance with section 6, shall include, as a minimum

(a) values of test data, test parameters, and test information established by paras. 5.5 and 9.1.

(b) summary of analysis and evaluation required per paras. 6.2 and 6.3.

(c) statement(s), by an individual qualified to make such a statement through the Owner's qualification requirements, confirming that the MOV is capable of performing its intended safety function.

(d) test results and analysis shall be evaluated by qualified individuals and documented to include signature and date. Independent verification shall be by individuals qualified to verify those specific analyses and evaluations through the Owner's qualification requirements.

Code Case OMN-3
Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants

Inquiry: Is it acceptable to categorize those components under the scope of the ASME OM Code Section IST into two categories based on their safety significance?

Reply: Yes, provided the following requirements are met.

1 APPLICABILITY

This Code Case establishes the component safety categorization methodology and process for dividing the population of pumps and valves, as identified in the IST Program Plan, into "high safety significant component" (HSSC) and "low safety significant component" (LSSC) categories.

2 SUPPLEMENTAL DEFINITIONS

aggregate risk: the risk due to programmatic changes in the IST program (test method effectiveness and/or testing interval) as measured by CDF or LERF.

basic event: basic fault event in a fault-free model that requires no further development, because appropriate limit of resolution has been reached.

common cause failure (CCF): a single event that adversely affects two or more components at the same time.

core damage frequency (CDF): the calculated frequency (per year) that core damage will occur due to failure of a critical safety function (i.e., reactivity control, core cooling, or containment heat removal). (A Level 1 PRA identifies accident sequences that can lead to core damage, calculates the frequency of each sequence, and sums those frequencies to obtain CDF.)

decision criteria: the quantitative and qualitative factors that influence a decision. These include both quantitative screening criteria (for PRA model) and the evaluation of other qualitative (or deterministic) factors that influence the results of an application.

figures-of-merit: the quantitative value, obtained from a PRA analysis, used to evaluate the results of an application (e.g., CDF, LERF).

Fussell-Vesely (F-V) importance measure: for a specified basic event, Fussell-Vesely importance is the fractional contribution to the total of a selected figure of merit for all accident sequences containing that basic event.

high safety significant components (HSSCs): components that have been designated as more important to plant safety by a blended process of PRA risk ranking and Plant Expert Panel evaluation.

importance measure: a mathematical expression that defines a quantity of interest. The most common importance measures are F-V and RAW.

initiating event: any event that perturbs the steady state operation of the plant, if operating, or the steady state operation of the decay heat removal system during shutdown operations, thereby initiating a transient within the plant. (Initiating events trigger sequences of events that challenge plant control and safety systems.)

inservice test (IST): a test to determine the operational readiness of a component/system.

large early release frequency (LERF): the calculated frequency (per year) that radioactivity release from the containment is both large and early. "Large" means involving the rapid, unscrubbed release of airborne fission products to the environment. "Early" means occurring before the effective implementation of off-site emergency and protective actions. (A Level 2 PRA identifies accident sequences that can lead to radioactivity release, calculates the frequency of each sequence, and sums these frequencies to obtain LERF.)

living PRA: a plant specific PRA that is maintained up to date, such that plant modifications, plant operation changes (including procedure changes), component performance, and other technical information significantly affecting the model are reflected in the model.

low safety significant components (LSSCs): components that have been designated as less important to plant safety by a blended process of PRA risk ranking and Plant Expert Panel evaluation.

operational readiness: the ability of a component to perform its intended system function when required.

PRA failure rate: the conditional probability of failure of a component on the next demand (for standby component) or in the next hour of operation (for operating component), given that it has not already failed.

probabilistic risk assessment (PRA): a quantitative assessment of the risk associated with plant operation and maintenance. Risk is measured in terms of the frequency of occurrence of different events, including core damage. In general the scope of a PRA is divided into three categories: Level 1, Level 2, and Level 3. A Level 1 maps from initiating events to plant damage states, including their aggregate, core damage. Level 2 includes Level 1 mapping from initiating events to release categories (source term). A Level 3 includes Level 2 and uses the source term of Level 2 to quantify consequences, the most common of which are health effects and property damage in terms of cost.

risk achievement worth (RAW) importance measure: for a specified basic event, risk achievement worth importance reflects the increase in a selected figure of merit when an SSC is assumed to be unable to perform its function due to testing, maintenance, or failure. It is the ratio or interval of the figure of merit, evaluated with the SSC's basic event probability set to one, to the base case figure of merit.

testing strategy: the IST strategy to measure component degradation or to monitor a component for operational readiness at some interval by operating or inspecting the component (e.g., valve stroking, pump vibration test, motor circuit evaluation, motor current signature analysis, component bearing lube oil analysis).

truncation limits: the cutoff value of probability or frequency of individual accident sequences below which they are no longer retained in quantitative PRA model results.

3 GENERAL REQUIREMENTS

3.1 Implementation

The requirements of the risk-informed IST component code cases shall be implemented for all IST components of the same type. Component types are specified in the risk informed component code cases.

3.2 Plant Specific PRA

The plant specific PRA (Level 1 with internal initiating events, as a minimum) shall be available and used to perform component risk ranking.

3.3 Living PRA

The PRA shall be maintained up to date. (Reference [1] provides guidance.)

3.4 Integrated Effects

Components may be affected by more than one risk informed application. Integrated effects of multiple risk informed applications (including risk informed applications outside of the ASME scope) shall be evaluated.

3.5 Plant Expert Panel

A Plant Expert Panel shall be designated to perform the blended safety evaluation of probabilistic and deterministic engineering information for each component.

3.6 Determination of HSSC and LSSC

The Plant Expert Panel shall evaluate each component and categorize it as HSSC or LSSC, using PRA quantitative information (if component is modeled) and engineering qualitative information (for both modeled and not modeled components).

3.7 Inservice Testing Strategy for HSSCs and LSSCs

Testing strategies will be developed by other risk-informed component code cases

(a) Test strategies for the HSSCs shall have the objective of identifying and trending degradation that could lead to the occurrence of the failure mode(s) that resulted in the HSSC categorization.

(b) Test strategies for LSSCs shall have the objective of providing confidence for operational readiness.

3.8 Evaluation of Aggregate Risk

The aggregate risk impact of changes to the IST program shall be evaluated by the Owner (e.g., plant expert panel). Decision criteria, quantitative evaluations, and qualitative assessments are a part of this aggregate risk impact evaluation. Reference [1] provides guidance on evaluating aggregate risk.

3.9 Feedback and Corrective Actions

Feedback and corrective action processes are required elements of this Code Case.

4 SPECIFIC REQUIREMENTS

In addition to section 3 above, the following requirements apply to component classification into HSSC and LSSC categories, and to a risk-informed IST program based on those categories.

4.1 Component Risk Categorization

This paragraph establishes requirements for separating components into HSSC or LSSC categories, performing PRA sensitivity studies to ensure that quantitative ranking is correct, and determining how to treat components not modeled.

4.1.1 Appropriate Failure Modes. Component risk categorization shall be based on basic events that include failure modes representing functions addressed by inservice testing (e.g., pump failure to run, valve failure to open, common cause failure).

4.1.2 Importance Measures

(a) As a minimum, two importance measures, F-V and RAW, shall be calculated for those components modeled in the PRA.

(b) Importance measures should be evaluated for both CDF and LERF, if available.

4.1.3 Screening Criteria. For those components modeled in the PRA *(a)* a threshold value of F-V > 0.005 or lower based on either CDF or LERF should be initially considered as HSSC

(b) a threshold value of RAW > 2 based on either CDF or LERF shall be initially considered as HSSC

4.1.4 Sensitivity Studies

(a) The following sensitivity studies shall be performed:

(1) Data and Uncertainties. Failure probabilities of components within the PRA models for those IST components that have initially very high or very low safety significance shall be selectively increased and/or decreased to determine if the results are sensitive to changes in the failure data. If sensitivities are indicated, steps shall be taken to determine if uncertainty ranges can be reduced and to validate the failure probabilities included in the models.

(2) Human Recovery Actions. The PRA shall be requantified, and the F-V and RAW importance measures recalculated, after human actions modeled in the PRA to recover from specific component failures are adjusted in the models (i.e., the probability of successful recovery due to human intervention is adjusted by factor of 10).

(3) Test and Maintenance Unavailabilities. The PRA models shall be requantified with test and maintenance unavailabilities adjusted, and the importance measures recalculated.

(4) LSSC Failure Rates. Failure rates for initially ranked LSSC components shall be increased by a factor representing the upper bound (95%) of the failure rate and the PRA models requantified. The importance measures shall then be recalculated.

(5) Truncation Limits. If the PRA has not been quantified with a truncation limit in accordance with Reference [1], the PRA model shall be requantified with the truncation limit lowered to this value. The importance measures shall then be recalculated.

(6) Common Cause. Sensitivity analyses shall determine the impact of increased or decreased common cause failure rates. Importance measures shall then be recalculated.

(b) The results of these sensitivity studies and any others that are performed shall be documented. In addition to the magnitude of the changes to the CDF or LERF, all insights obtained from the results shall be described.

(c) The results and insights of these sensitivity studies shall be provided to the Plant Expert Panel for their consideration in the final categorization of the components.

4.1.5 Qualitative Assessments. Qualitative assessments shall be performed for all IST components, modeled and not modeled in the PRA to determine whether there are other bases for categorizing IST components.

(a) The following qualitative assessments shall be performed:

(1) impact of initiating events (i.e., the impact of failure or degradation as it might result in an initiator, component contribution to initiating events represented by point estimates)

(2) potential consequences of shutdown (outage) conditions

(3) response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding, etc.)

(4) impact of LERF, if not used in subpara. 4.1.2(b)

(b) Qualitative assessments shall be performed for plant-specific design bases conditions and events not modeled in a PRA.

(c) Qualitative assessments shall consider the impacts upon the plant to

(1) prevent or mitigate accident conditions

(2) reach and/or maintain safe shutdown conditions

(3) preserve the reactor primary coolant pressure boundary integrity

(4) maintain containment integrity

(d) Qualitative assessments shall also consider

(1) safety function being satisfied by the component's operation

(2) level of redundancy existing at the plant to fulfill the component's function

(3) ability to recover from a failure of the component

(4) performance history of the component

(5) plant technical specifications requirements applicable to the component

(6) emergency operating procedure instructions that use the component(s)

(7) design and current licensing basis information relevant to IST component function

(e) The cumulative impacts of combinations of component unavailability, which could impact an entire system (e.g., multitrain impacts) or critical safety function (e.g., multisystem impacts), shall also be considered.

(f) These qualitative assessments shall be available to the Plant Expert Panel for their decision of component safety categorization.

(g) These qualitative assessments and the Plant Expert Panel's disposition of them shall be documented.

4.1.6 Components Not Modeled. If IST components not modeled in the PRA are subsequently determined by the Plant Expert Panel to have an impact upon the ability of the facility to respond to analyzed events, consideration should be given to updating the PRA model to incorporate the effects of the component(s), then using the updated model to provide a quantified basis for categorization (either HSSC or LSSC).

4.2 Component Safety Categorization

This paragraph provides requirements for the Plant Expert Panel's review and evaluation process for categorizing IST components relative to their safety significance, using both deterministic and probabilistic insights.

4.2.1 Plant Expert Panel Utilization. The Plant Expert Panel shall blend deterministic and probabilistic information to classify IST components into HSSC or LSSC categories.

(a) PRA Insights. The results of PRA analyses shall be used by the Plant Expert Panel to determine the safety significance of components within the scope of IST and PRA programs. Information contained in PRAs relative to the role of components in mitigating or preventing core damaging events or radiological release events shall be considered. The scope of the PRA and depth of probabilistic analyses shall be assessed, evaluated, and documented. As a minimum, the following shall be documented:

(1) the level of plant-specific PRA analysis available for assessing the applicability of PRA information relative to IST programs. For example, written documentation describing the level of plant-specific PRA analysis such as Level 1 PRA (assessment of core damage frequency) and/or Level 2 PRA (assessment of core damage frequency plus containment performance).

(2) scope of initiating events considered (internal events, external events, both).

(3) typical failure modes considered (e.g., hardware failures, testing/maintenance failures, common cause failures, human errors).

(4) PRA scope for plant configurations (e.g., low power risk, shutdown risk, transition mode risk, at-power risk) reviewed relative to the applicability of PRA information and IST component function(s).

(b) Deterministic Insights. The Plant Expert Panel shall also consider deterministic factors when assessing the safety significance of components within the scope of IST programs. (See Nonmandatory Appendix A of this Code Case for a sample list of deterministic questions.)

4.2.2 Plant Expert Panel Requirements

(a) Plant Procedure. A procedure approved by the Owner shall describe the process, including

(1) designated members and alternates
(2) designated chairman and alternate
(3) quorum
(4) attendance records
(5) agendas
(6) motions for approval
(7) process for decision making
(8) documentation and resolution of differing opinions
(9) minutes
(10) implementation of feedback/corrective actions
(11) feedback to the PRA
(12) required training

(b) Training. The Plant Expert Panel shall be trained and indoctrinated by the Owner in the specific requirements to be used for this Code Case. Training and indoctrination shall include the application of risk analysis methods and techniques used for this Code Case. At a minimum, the risk methods and techniques include

(1) PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty)
(2) use of risk importance measures
(3) assessment of failure modes
(4) reliability versus availability
(5) risk thresholds
(6) expert judgment elicitation

Each of the aforementioned topics shall be covered in the indoctrination to the extent necessary to provide the Plant Expert Panel with a level of knowledge needed to adequately evaluate and approve the scope of the IST selections, using both probabilistic and deterministic information.

(c) Expertise. There shall be requirements for ensuring adequate expertise levels of Plant Expert Panel members. Member expertise levels shall be documented and maintained.

(d) Membership

(1) There shall be at least five experts designated as members of the Plant Expert Panel. Members may be experts in more than one field; however, excessive reliance on any one member's judgment shall be avoided.

(2) The chairperson shall be familiar with this Code Case and shall facilitate Plant Expert Panel activities, to ensure that the requirements of this Code Case are satisfied.

(3) Expertise in the following functions shall be represented on the Plant Expert Panel:

(-a) operation
(-b) safety analysis engineering
(-c) probabilistic risk assessment

(4) Additional members of the Plant Expert Panel who have the following plant expertise may be selected:

(-a) systems performance
(-b) maintenance
(-c) licensing
(-d) component performance
(-e) ASME inservice testing
(-f) quality assurance
(-g) design engineering

(5) Alternate members may be designated to the Plant Expert Panel on a temporary basis; however, vacancies in the Plant Expert Panel membership should

be filled by qualified individuals within a reasonable period of time.

(6) Other plant or nuclear industry experts may be invited to attend some or all of the sessions of the Plant Expert Panel as visitors to provide observations, opinions, or recommendations.

4.2.3 Plant Expert Panel Decision Criteria. Plant Expert Panel decision criteria for categorizing components as HSSC and LSSC shall be documented.

4.2.4 Reconciliation. Decisions of the Plant Expert Panel shall be arrived at by consensus. Differing opinions shall be documented and resolved, if possible.

(a) If a resolution cannot be achieved concerning the safety significance classification of a component, then the component shall be classified HSSC.

(b) If components have a high initial ranking from the PRA (i.e., RAW > 2 or F-V > 0.005) but are ultimately ranked as LSSCs, the Plant Expert Panel decisions shall be documented.

4.3 Testing Strategy Formulation

(a) Testing strategies for HSSCs and LSSCs shall be developed following the requirements provided in the risk-informed component code cases.

(b) After testing strategies are developed, the Owner shall provide the planned changes (e.g., test frequency, testing effectiveness, and test duration) for input to the evaluation of aggregate risk.

4.4 Evaluation of Aggregate Risk

4.4.1 Decision Criteria

(a) Appropriate decision criteria for aggregate risk effects shall be established and documented.

(1) Decision criteria shall be based on thresholds for aggregate risk limits using standard figures-of-merit (e.g., CDF, LERF). (Nonmandatory Appendix B of this Code Case provides guidance.)

(2) Performance criteria used for other regulatory requirements may be taken into consideration when developing decision criteria for aggregate risk effects.

(b) Decision criteria may be determined both qualitatively and quantitatively.

4.4.2 Quantitative Assessment

(a) An aggregate risk evaluation shall be performed prior to implementation, as applicable, using the PRA.

(1) Quantitative attributes associated with this Code Case shall be considered and included in the quantitative evaluation, as appropriate, and within the scope of the PRA.

(2) Each applicable quantitative IST attribute shall be incorporated into the quantitative evaluation, as appropriate, until all proposed changes have been dispositioned (i.e., incorporated or not incorporated).

(3) Once all appropriate inputs have been incorporated, the PRA shall be rerun to assess the overall risk impact.

(4) Proposed IST program change shall be assessed to determine compliance with approved decision criteria and to quantitatively determine if any adjustments or compensatory measures are warranted.

(b) Types of quantitative attributes that should be considered in the quantitative evaluation include changes in

(1) testing frequency
(2) out of service duration
(3) failure rates
(4) failure modes
(5) common cause failure susceptibility
(6) compensatory measures
(7) testing scheme (staggered or simultaneous testing)

Compensatory measures include both those specifically incorporated into plant programs and those developed by the Owner for specific situations. Management directed compensatory measures should also be included in the quantitative assessment, as appropriate. Verifiable values of failure rates shall be used in the quantification process for IST component.

(c) Testing effectiveness shall be evaluated by periodic assessments or when new failure modes are identified that impact risk quantification.

(1) New failure modes shall be incorporated in accordance with the Owner's risk management and corrective action programs into the quantitative evaluation, as appropriate.

(2) Changes resulting from programs that significantly affect the reliability or availability of components that perform important safety functions shall be assessed, and, if appropriate, incorporated into the PRA for requantification.

Such assessments may be performed in conjunction with the plant-specific Maintenance Rule (10 CFR 50.65) requirements.

4.4.3 Qualitative Evaluation

(a) Aggregate risk effects shall be qualitatively evaluated (i.e., risk decreases as well as risk increases) for IST program changes (e.g., testing effectiveness).

(b) Pertinent performance indicators, industry programs, or other scrutable methods for establishing aggregate risk effects shall be identified and monitored.

(c) Feedback processes and corrective action programs shall be considered in the evaluation of aggregate risk.

4.4.4 Defense in Depth. The IST aspects of Defense in Depth shall be maintained.

4.4.5 Safety Margins. The IST aspects of Safety Margin shall be maintained.

4.5 Inservice Testing Program

4.5.1 Maximum Testing Interval. The maximum testing interval shall be based on the more limiting of the following:
(a) the results of the aggregate risk
(b) performance history of the component

4.5.2 Implementation Schedule. A schedule shall be developed for implementing the testing strategies as specified in the risk-informed component code cases.

4.5.3 Assessment of Aggregate Risk. Once the test schedule has been developed, the schedule shall be assessed against the assumptions of the aggregate risk evaluation.

4.5.4 Transition Plan. A transition plan shall be developed for each component type to ensure adequate information is collected to support justification of stepwise test interval extension up to and including the maximum allowable interval. Staggered test intervals are acceptable for implementing a stepwise test interval extension.

4.6 Performance Monitoring

4.6.1 HSSC Attribute Trending. For HSSCs, a set of attributes to be tested shall be established in accordance with the requirements of risk-informed component code cases, and a trending program shall be implemented for those attributes selected for monitoring.

4.6.2 LSSC Performance Trending. For LSSCs, testing strategies shall be identified in accordance with the requirements of risk-informed component code cases and shall trend component performance.

4.7 Feedback and Corrective Actions

4.7.1 Feedback

(a) A feedback process incorporating elements of both conditional and periodic feedback shall be established such that component performance information is directed to both the IST and PRA programs. Conditional feedback shall occur in a timely fashion following component failure. Periodic feedback shall be considered for maintenance of the PRA.

(b) Each program shall assimilate performance information to ensure the appropriate unavailability information is reflected in decision making.

(c) A feedback process shall be established so IST programmatic changes are directed to the PRA program.

4.7.2 Corrective Action. In addition to the requirements in the IST Code of Record with respect to Corrective Actions, a Corrective Action Program shall be established that identifies and tracks to resolution all failures of similar types of components within an IST Program incorporating risk insights, including evaluation of generic implications.

4.7.3 Component Safety Recategorization. The component's operational readiness is not changed by recategorization.

5 TO BE PROVIDED AT A LATER DATE

6 TO BE PROVIDED AT A LATER DATE

7 TO BE PROVIDED AT A LATER DATE

8 RECORDS AND REPORTS

In addition to the requirements in the Code of Record with respect to Records, the following records of the Plant Expert Panel and the component shall be maintained.

8.1 Plant Expert Panel Records

(a) membership and attendance
(b) member expertise representation and training records per subpara. 4.2.2(b)
(c) member experience (years of experience in each of the expertise categories)
(d) meeting agendas
(e) meeting minutes
(f) plant procedure

8.2 Component Records

(a) risk significance based on PRA importance measures
(b) additional PRA quantitative information
(c) deterministic information
(d) plant Expert Panel categorization decisions of HSSC or LSSC
(e) basis for the HSSC/LSSC decision

9 REFERENCE

[1] EPRI TR. 105396, PSA Applications Guide, August 1995

Nonmandatory Appendix A
Sample List of Component Deterministic Questions

This Nonmandatory Appendix provides guidance to the Plant Expert Panel for categorizing components as HSSC or LSSC.

A-1 DESIGN BASIS ANALYSIS

(a) Is component considered in design basis analysis?

(b) Is component function considered important in the Safety Analysis Report?

(c) Are there any Tech Spec considerations for this component?

A-2 RADIOACTIVE MATERIAL RELEASE LIMIT

(a) Could the failure of this component be considered a breach in an engineered safety barrier?

(b) Could the failure of this component result in an uncontained release of radioactive material in excess of that allowed?

A-3 MAINTENANCE RELIABILITY

(a) Is component important to maintaining system reliability?

(b) What type of component failures have been experienced for this and similar style components?

(c) What does the maintenance history indicate about the reliability of this component?

(d) Does the component receive preventive maintenance and is it effective for preventing identified failures?

(e) How are component failures detected?

A-4 EFFECT OF COMPONENT FAILURE ON SYSTEM OPERATIONAL READINESS

(a) Is component important to maintaining system availability?

(b) How does component failure affect system performance?

(c) Does component failure cause other system component failures?

(d) What is the system component level of defense in depth?

(e) Does the system or component perform other functions outside the scope of the PRA?

(f) Can system or component failure modes affect redundant trains or other similar component?

A-5 OTHER DETERMINISTIC CONSIDERATIONS

(a) Should other component failure modes be considered in the PRA model?

(b) Is this component used to mitigate the consequences of an accident caused by external events?

(c) Is this component important for safe shutdown?

(d) Is this component required to maintain the safe shutdown condition?

(e) Should other component failure modes that may not be included in the PRA be considered (e.g., aging effects, structural supports, human performance failures)?

Nonmandatory Appendix B
Acceptance Guidelines

This Nonmandatory Appendix provides guidance on the decision criteria for aggregate risk limits using CDF and LERF.

The risk acceptance guidelines presented in this Nonmandatory Appendix are structured as follows. Regions are established in the two planes generated by a measure of the baseline risk metric (CDF or LERF) along the *x*-axis, and the change in those metrics (CDF or LERF) along the *y*-axis (Figs. B-1 and B-2), and acceptance guidelines are established for each region as discussed below. These guidelines are intended for comparison with a full PRA scope (including internal events, external events, full power, low power, and shutdown) assessment of the change in risk metric, and, when necessary, as discussed below, the baseline value of the risk metric (CDF or LERF). However, it is recognized that many PRAs are not full scope and the use of less than full-scope PRA information is acceptable as discussed in this Code Case.

There are two acceptance guidelines, one for CDF and one for LERF, both of which should be used.

(a) The acceptance guidelines for CDF are as follows:

(1) If the change can be clearly shown to result in a decrease in CDF, then the change is satisfactory.

(2) When the calculated increase in CDF is very small, which is taken as being less than 1E−06 per reactor year, the change should be considered, regardless of whether there is a calculation of the total CDF (Region III). While there is no requirement to calculate the total CDF, should there be an indication that the CDF may be considerably higher than 1E−04 per reactor year, then the focus should be on finding ways to decrease CDF. Such an indication would result, for example, if

(-a) the contribution to CDF calculated from a limited scope analysis, such as the PRA, and, if appropriate the PRA with external initiating events, significantly exceeds 1E−04

(-b) there has been an identification of a potential vulnerability from a margin-type analysis or

(-c) historical experience at the plant in question has indicated a potential safety concern

(3) When the calculated increase in CDF is in the range of 1E−06 per reactor year to 1E−05 per reactor year, changes should only be considered if it can be reasonably shown that the total CDF is less than 1E−04 per reactor year (Region II).

(4) Applications that result in increases to CDF above 1E−05 per reactor year (Region I) should not normally be considered.

(b) The acceptance guidelines for LERF are as follows:

(1) If the change can be clearly shown to result in a decrease in LERF, then the change is satisfactory.

(2) When the calculated increase in LERF is very small, which is taken as being less than 1E−07 per reactor year, the change should be considered, regardless of whether there is a calculation of the total LERF (Region III). While there is no requirement to calculate the total LERF, should there be an indication that the LERF may be considerably higher than 1E−05 per reactor year, then the focus should be on finding ways to decrease rather than increase it. Such an indication would result, for example, if

(-a) the contribution to LERF calculated from a limited scope analysis, such as that the IPE and, if appropriate, the IPEEE significantly exceed 1E−05

(-b) there has been an identification of a potential vulnerability from a margin-type analysis or

(-c) historical experience at the plant in question has indicated a potential safety concern

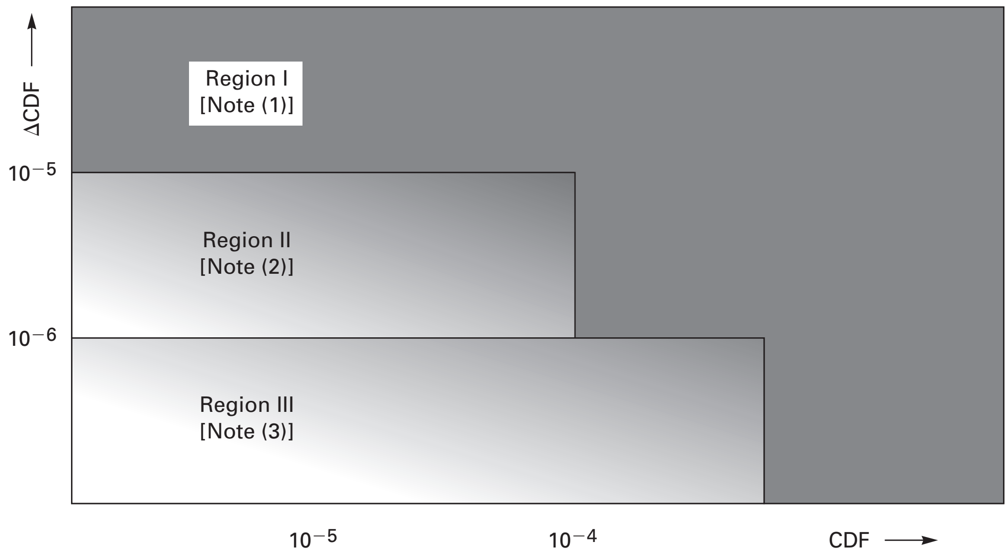
(3) When the calculated increase in LERF is in the range of 1E−07 per reactor year to 1E−06 per reactor year, changes should only be considered if it can be reasonably shown that the total LERF is less than 1E−05 per reactor year (Region II).

(4) Changes that result in increases to LERF above 1E−06 per reactor year (Region I) should not normally be considered.

These acceptance criteria are intended to provide assurance that proposed increases in CDF and LERF are small.

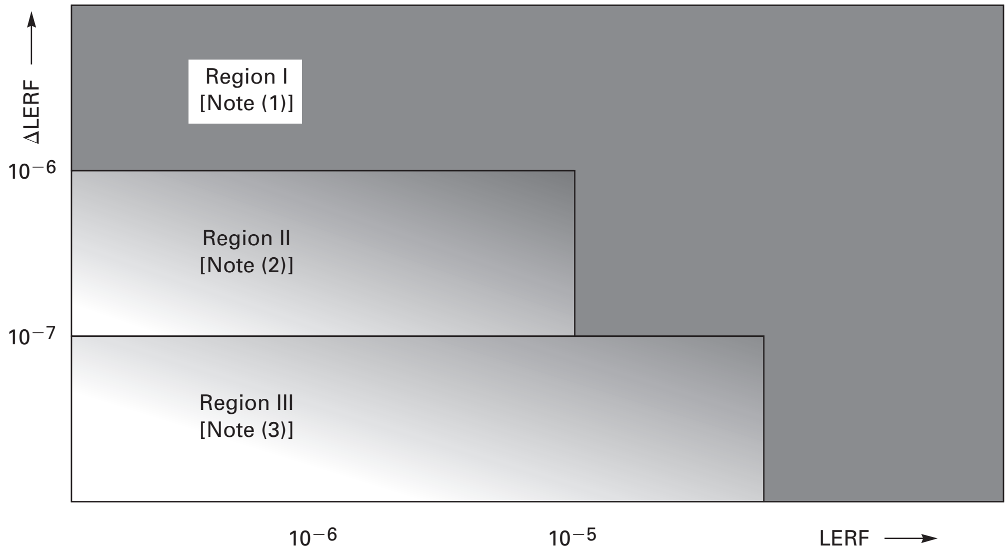
The analysis may be subject to a more detailed technical and management review depending upon the degree to which a change resides in a given region. In the context of the integrated decision making by the Plant Expert Panel, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as being absolute.

Fig. B-1 Acceptance Guidelines for CDF (From RG 1.174)



NOTES:
(1) Region I: No changes allowed.
(2) Region II:
  (a) Small changes
  (b) Track cumulative impacts
(3) Region III:
  (a) Very small changes
  (b) More flexibility with respect to baseline CDF
  (c) Track cumulative impacts

Fig. B-2 Acceptance Guidelines for LERF (From RG 1.174)



NOTES:

(1) Region I: No changes allowed.

(2) Region II:

(a) Small changes

(b) Track cumulative impacts

(3) Region III:

(a) Very small changes

(b) More flexibility with respect to baseline LERF

(c) Track cumulative impacts

Code Case OMN-4
Requirements for Risk Insights for Inservice Testing of Check Valves at LWR Power Plants

Inquiry: What alternative requirements may be used in lieu of the requirements of the ASME OM Code for inservice exercising tests for Category C check valves?

Reply: It is the opinion of the Committee that the following requirements may be applied.

1 SAFETY SIGNIFICANCE CATEGORIZATION

Check valves shall be evaluated and categorized as high safety significant components (HSSCs) or low safety significant components (LSSCs) in accordance with the Code Case on Requirements for safety significance categorization of components using Risk Insights for Inservice Testing of LWR Power Plants.

2 HSSC TESTING

HSSC check valves shall be placed in a Condition Monitoring Program and tested in accordance with ASME OMa Code-1996, Appendix II. The Condition Monitoring program shall include identification and trending of attributes indicative of degradation that could lead to the occurrence of the failure mode(s) that resulted in HSSC categorization.

3 LSSC TESTING

LSSC check valves shall be tested in accordance with OMa Code-1996, Subsection ISTC, or placed in a Condition Monitoring Program and tested in accordance with the ASME OMa Code-1996, Appendix II.

Code Case OMN-6
Alternate Rules for Digital Instruments

Inquiry: What alternative requirements to those specified in OM Code, subparas. ISTB-4.6.1(b)(2) (1990 Edition through the OMb-1992 Addenda), ISTB-4.7.1(b)(2) (OMc-1994 Addenda through OMc-1997 Addenda), and ISTB-3510(b)(2) (1998 Edition through the OMa-2005 Addenda) may be used for digital instruments used in the performance of inservice testing?

Reply: It is the opinion of the Committee that digital instruments may be selected such that the reference value does not exceed 90% of the calibrated range of the instrument.

Applicability: ASME OM Code-1990 and later editions and addenda through the OMa-2005 Addenda.

Code Case OMN-7
Alternative Requirements for Pump Testing

Inquiry: What alternative to the requirements of ASME OM Code, Subarticle ISTB-5.1 may be used in conjunction with Code Case OMN-3, Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants, for inservice testing to assess the operational readiness of pumps in light water reactor power plants?

Reply: It is the opinion of the Committee that, in lieu of the rules of ASME OM Code, Subsection ISTB, Subarticle ISTB-5.1, the following alternative requirements may be applied.

1 APPLICABILITY

The pumps covered by this Code Case are all those pumps determined to be within the scope of the risk-informed IST Program in accordance with Code Case OMN-3, Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants.

2 REQUIREMENTS

2.1 Related Requirements

Use of this Code Case also requires compliance with the requirements of ASME Code Case OMN-3 (risk ranking). Code Case OMN-3 groups components into one of two categories

(a) high safety significant component (HSSC).

(b) low safety significant component (LSSC). Trending of parameters according to OM Code-1995 with OMa Code-1996 meets the performance monitoring requirements of Code Case OMN-3, para. 4.6.

2.2 HSSC Testing Requirements

Group A and Group B pumps categorized as HSSCs shall meet all the requirements of OM Code-1995 with OMa Code-1996.

2.3 LSSC Testing Requirements

Group A and Group B pumps categorized as LSSCs shall meet all the requirements of OM Code-1995 with OMa Code-1996, except that the testing requirements identified in this paragraph and in the table below may be substituted for those in para. ISTB 5.1 (Table ISTB 5.1-1). All Group A and Group B LSSC pumps shall receive an initial Group A test conducted within ±20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of this Code Case. Thereafter, all Group A and Group B LSSC pumps shall be Group A tested within ±20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.

Pump Group	Group A Test	Group B Test	Comprehensive Test
Group A (routinely or continuously operated pumps)	6 months [Note (1)]	Not required	Not required
Group B (standby pumps)	2 yr	6 months [Note (1)]	Not required

NOTE:
(1) To meet vendor recommendations, pump operation may be required more frequently than the specified test frequency.

3 ADDITIONAL REQUIREMENTS

(a) The Owner shall develop a transition plan and implementation schedule for this Code Case.

(b) Feedback and corrective actions shall be taken in accordance with Code Case OMN-3, para 4.7.

(c) If the maximum test interval as determined from the aggregate risk assessment of Code Case OMN-3, para. 4.5.2, for a specific component is more limiting than the test frequency of para. 2.2 or 2.3 above (as applicable), the most limiting test interval shall be used for that component. A Group A or Group B test, as applicable, shall be performed to satisfy the increased test frequency requirements.

Code Case OMN-8
Alternative Rules for Preservice and Inservice Testing of Power-Operated Valves That Are Used for System Control and Have a Safety Function Per OM-10, ISTC-1.1, or ISTA-1100

Inquiry: What alternative requirements to those of ASME/ANSI OMa-1988, Part 10, para. 4.2 through OM Code-2004, article ISTC-5100 may be used for power-operated control valves that have only a fail-safe safety function?

Reply: It is the opinion of the Committee that for power-operated control valves that have only a fail-safe safety function, the requirements for valve stroke-time measurement testing, the associated requirements for stroke test acceptance criteria, and the associated resulting requirements for stroke-time testing corrective actions need not be met. All other requirements applicable for these valves shall be met. If a valve fails to exhibit the required change of obturator position during the exercise test, the valve shall immediately be declared inoperable and corrective actions initiated. Any abnormality or erratic action observed during exercise testing of these power-operated control valves shall be recorded in the record of tests, and an evaluation shall be made regarding the need for corrective action.

Code Case OMN-9
Use of a Pump Curve for Testing

Inquiry: What alternative rules to those of paras. ISTB 4.3, 4.4, 4.5, 5.2, and 6.1 may be used when it is impractical to adjust a centrifugal or vertical line shaft pump to a specific reference value as required by subpara. ISTB 5.2(b)?

Reply: It is the opinion of the Committee that the following rules may be used for testing of centrifugal or vertical line shaft pumps where adjustment to a specific reference value is impractical, in lieu of the requirements of paras. ISTB 4.3, 4.4, 4.5, 5.2, and 6.1.

Applicability: ASME OM Code-1990 through ASME OMb Code-1992.

1 ADDITIONAL DEFINITIONS

maximum pump curve range: the maximum potential flow or differential pressure range for the pump curve, from shutoff conditions to maximum required flow rate.

reference curve: a range of values of a test parameter versus flow or differential pressure, for a centrifugal or vertical line shaft pump, measured or determined when the pump is known to be operating acceptably.

2 REFERENCE VALUES

Reference values shall be determined from the results of preservice testing or from the results of the first inservice test. Reference values shall be at points of operation readily duplicated during subsequent tests. All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with sections 4 and 5 below. Reference values shall only be established when the pump is known to be operating acceptably. If the particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed.[1]

3 REFERENCE CURVES

If the establishment of specific reference values is impractical for a centrifugal or vertical line shaft pump, the Owner may establish reference curves. Reference curves shall be determined from data measured during preservice testing or from the first inservice test. A reference curve shall be established from a minimum of three data points and shall have at least one data point for each 20% of the maximum pump curve range. The range of the reference curve shall be sufficient to bound the points of operation expected during subsequent tests. All subsequent test results shall be compared to the initial reference curves or to new reference curves established in accordance with section 4 or 5 below. Reference curves shall only be established when the pump is known to be operating acceptably. If vibration is relatively unaffected by changing differential pressure or flow over the reference curve range, a single reference value may be used for that test quantity, provided it is at the minimum of the measured data. If reference curves are used, the reasons for doing so and the suitability of the methods used to develop the reference curves and acceptance criteria shall be justified and documented in the record of tests (see section ISTB 7).

4 EFFECT OF PUMP REPLACEMENT, REPAIR, AND MAINTENANCE ON REFERENCE VALUES OR REFERENCE CURVES

When a reference value, set of reference values, or reference curve may have been affected by repair, replacement, or routine servicing of a pump, a new reference value, set of reference values, or reference curve shall be determined or the previous value, or curve, reconfirmed by an inservice test run before declaring the pump operable. Deviations between the previous and new set of reference values or reference curves shall be identified, and verification that the new values or curves represent acceptable pump operations shall be placed in the record of tests (see section ISTB 7).

5 ESTABLISHMENT OF ADDITIONAL SET OF REFERENCE VALUES OR REFERENCE CURVES

If it is necessary or desirable, for some reason other than stated in section 4 above, to establish an additional set of reference values or reference curves, an inservice test shall be run at the conditions of an existing set of reference values, or within the range of existing reference curves, and the results analyzed. If operation is acceptable per section 7 below, a second test run at the new reference conditions shall follow as soon as practicable.

[1] Vibration of pumps may be foundation, driver, and piping dependent. Therefore, if initial vibration readings are high and have no obvious relationship to the pump, the vibration measurements should be taken at the driver, at the foundation, and on the piping, and analyzed to ensure that the reference vibration measurements are representative of the pump and that the measured vibration levels will not prevent the pump from fulfilling its function.

The results of this test shall establish the additional set of reference values or reference curves. Whenever an additional set of reference values or reference curves is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTB 7). The requirements of section 2 or 3 above apply.

6 TEST PROCEDURE

An inservice test shall be conducted with the pump operating at the specified test conditions. The test parameters shown in Table ISTB 5.2-1 shall be determined and recorded as directed in this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives and at a speed adjusted to the reference speed for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate equals the reference value. The pressure shall then be determined and compared to its reference value. Alternatively, the flow rate can be varied until the pressure equals the reference value, and the flow rate shall be determined and compared to the reference flow rate value.

(c) Where system resistance cannot be varied or if reference curves are used, flow rate and pressure shall be determined and compared to their respective reference values or the associated reference values from the reference curves.

(d) Pressure, flow rate, and vibration (displacement or velocity) shall be determined and compared with corresponding reference values or associated reference values from the reference curves. All deviations from the reference values shall be compared with the limits given in Table ISTB 5.2-2 and Fig. ISTB 5.2-1, and corrective action taken as specified in section 7 below. If the reference curve test method is used, the comparison may be done graphically as shown in Examples 1 and 2 of Fig. 1.

Vibration measurements are to be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

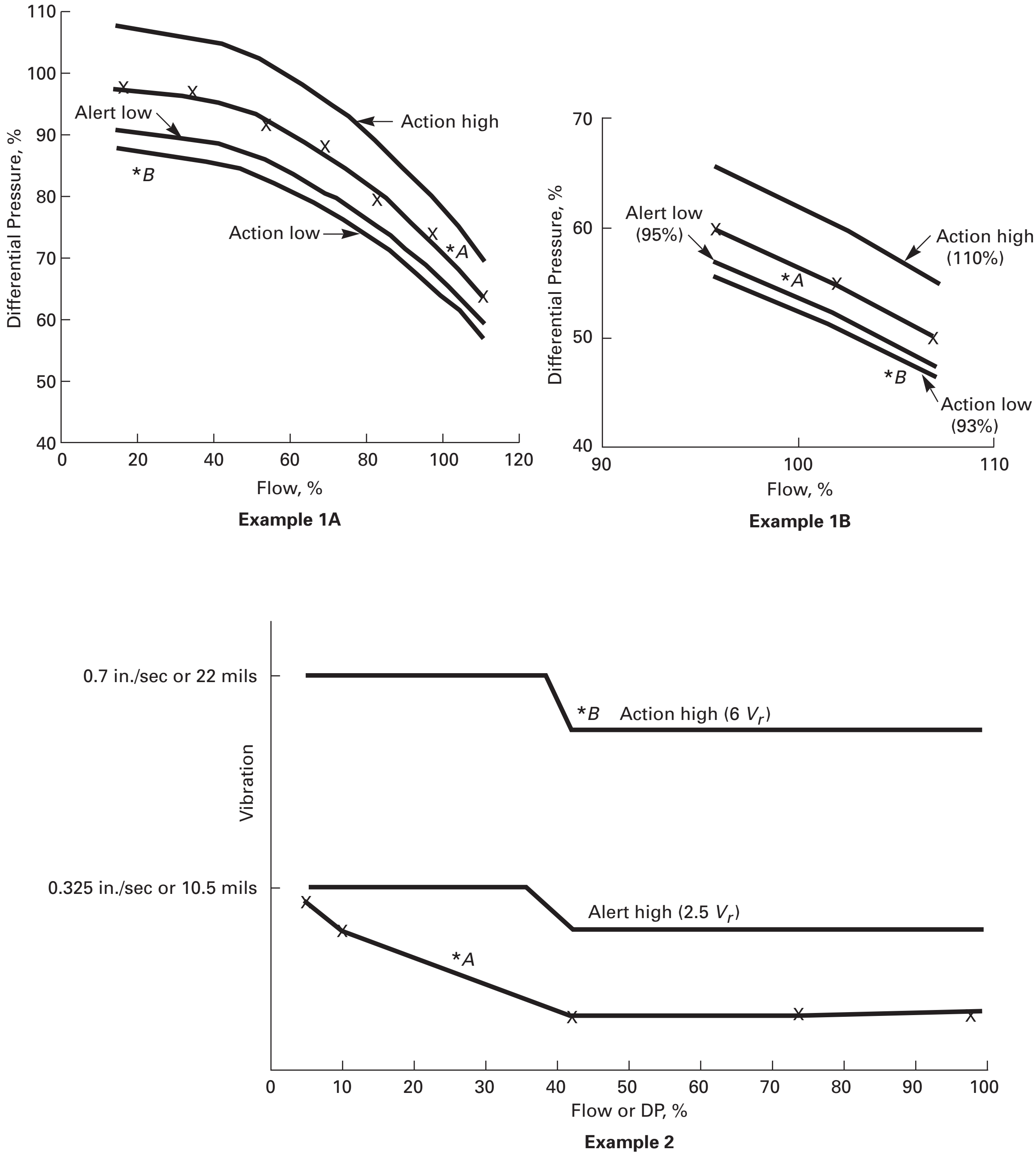
7 ACCEPTANCE CRITERIA

If deviations fall within the alert range of Fig. ISTB 5.2-1 and Table ISTB 5.2-2, the frequency of testing specified in para. ISTB 5.1 shall be doubled until the cause of the deviation is determined and the condition corrected. If deviations fall within the required action range of Table ISTB 5.2-2, the pump shall be declared inoperable until the cause of the deviation has been determined and the condition corrected. If using reference curves, evaluations for deviations in the alert or required action range may be done graphically as demonstrated in Examples 1 and 2 of Fig. 1. When a test shows deviations outside of the acceptable range of Table ISTB 5.2-2, the instruments involved may be recalibrated and the test rerun.

8 RECORDS AND REPORTS

Use of this Code Case shall be documented in the inservice test plans per para. ISTB 7.2.

Fig. 1 Examples of Graphical Evaluation of Tests Using Reference Curves



A = acceptable operation
B = required action
X = data points used to establish reference curve

Code Case OMN-10
Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for Inservice Testing of LWR Power Plants

Inquiry: Is it acceptable to categorize those snubbers under the scope of the ASME OM Code into two categories based on their significance for the purpose of applying different examination and testing strategies to those described in sections ISTD 6 and ISTD 7?

Reply: Yes, provided the following requirements are met.

1 APPLICABILITY

This Code Case establishes the safety categorization methodology and process for dividing the population of snubbers, as identified in the Owner's Snubber Program Plan, into high safety significant component (HSSC) and low safety significant component (LSSC) categories, and provides acceptable testing strategies for each category.

2 SUPPLEMENTAL DEFINITIONS

2.1 PRA Definitions

common cause failure (CCF): a single event that adversely affects two or more components at the same time.

core damage frequency (CDF): the calculated frequency (per year) that core damage will occur due to failure of a critical safety function (i.e., reactivity control, core cooling, or containment heat removal).

Fussell-Vesely (F-V) importance: the fractional decrease in total risk level (usually CDF) when the plant feature is assumed to be perfectly reliable (failure rate = 0.0).

importance measure: a mathematical expression that defines a quantity of interest. The most common importance measures are F-V and RAW.

large early release frequency (LERF): the calculated frequency (per year) that radioactivity release from containment is both large and early. "Large" means involving the rapid, unscrubbed release of airborne fission products to the environment. "Early" means occurring before the effective implementation of off-site emergency and protective actions.

Level 1 PRA: a PRA that identifies accident sequences that can lead to core damage, calculates the frequency of each sequence, and sums those frequencies to obtain CDF.

Level 2 PRA: a PRA that identifies accident sequences that can lead to radioactivity release, calculates the frequency of each sequence, and sums up those frequencies to obtain LERF.

living PRA: a plant-specific PRA that is maintained up to date, such that plant modifications, plant operation changes (including procedure changes), component performance, and other technical information significantly affecting the model are reflected in the model.

probabilistic risk assessment (PRA): a quantitative assessment of the risk associated with plant operation and maintenance. Risk is measured in terms of the frequency of occurrence of different events, including core damage. In general, the scope of a PRA is divided into three categories: Level 1, Level 2, and Level 3. A Level 1 maps from initiating events to plant damage states, including their aggregate, core damage. Level 2 includes Level 1 mapping from initiating events to release categories (source term). Level 3 includes Level 2 and uses the source term of Level 2 to quantify consequences, the most common of which are health effects and property damage in terms of cost.

risk achievement worth (RAW): the increase in risk of a modeled plant feature (usually a component, train, or system) when the feature is assumed to be out of service (failed). RAW is expressed in terms of the ratio of the risk with the event failed to the baseline risk level.

2.2 Safety Definitions

decision criteria: the quantitative and qualitative factors that affect a decision. These include both quantitative screening criteria (for PRA model) and the evaluation of other qualitative (or deterministic) factors that influence the results of an application.

Expert Panel: a multidisciplined group of experienced plant experts who evaluate specific information, discuss this information among themselves (and others as appropriate), and make HSSC and LSSC determinations.

high safety significant components (HSSCs): components that have been designated as more important to plant safety by a blended process of PRA risk ranking and Expert Panel evaluation.

low safety significant components (LSSCs): components that have been designated as less important to plant safety by a blended process of PRA risk ranking and Expert Panel evaluation.

technical specification: the plant technical specifications that are a condition of the plant operating license granted to the Owner by the regulator.

2.3 IST Definitions

active valve: valve that is required to change obturator position to accomplish the required design functions.

inservice test (IST): a test to determine the operational readiness of a component/system (snubber).

operational readiness: ability of a component (snubber) to perform its intended system function when required.

testing strategy: the IST strategy to measure component (snubber) degradation or to monitor a component (snubber) for operational readiness at some interval by operating, examining, or testing the component (snubber).

2.4 Snubber Definitions

component's snubber: snubbers required to protect a component (e.g., pump, valve) during a dynamic event.

equipment dynamic restraint (snubber): a device that provides restraint to a component or system during the sudden application of forces, but allows essentially free motion during thermal movement.

hydraulic snubbers: devices in which the load is transmitted through a hydraulic fluid.

mechanical snubbers: devices in which the load is transmitted entirely through mechanical components.

replacement snubber: any snubber other than the snubber immediately previously installed at a given location.

service conditions: the operating environment for the snubber (e.g., temperature, vibration, weather) at its installed plant location, categorized as harsh or benign.

service life: period of time an item is expected to meet the operational readiness requirements without maintenance.

3 GENERAL REQUIREMENTS

3.1 Implementation

The requirements of this Code Case shall be implemented for all snubbers identified in the Snubber Program Plan, after the Owner has transferred the plant snubber examination and testing requirements from the plant technical specification to an Owner-controlled document and adopted the OM Code.

3.2 Plant-Specific PRA

The plant-specific PRA (Level 1 with internal initiating events, as a minimum) shall be available and used to perform system risk ranking.

3.3 Living PRA

The PRA shall be maintained up to date [reference (b) in section 9 below provides guidance].

3.4 Expert Panel

An Expert Panel shall be designated to perform the blended safety evaluation of probabilistic and deterministic engineering information for snubbers.

3.5 Determination of HSSC and LSSC

The Expert Panel shall evaluate each snubber and categorize it as HSSC or LSSC.

3.6 Inservice Testing Strategies for HSSCs and LSSCs

Testing strategies shall be implemented for HSSC snubbers and for LSSC snubbers.

3.7 Other Requirements

Subsection ISTD of reference (a) in section 9 below provides examination and testing requirements for snubbers. Any requirements not specifically addressed by alternative requirements in this Code Case shall stand.

4 SPECIFIC REQUIREMENTS FOR SAFETY CATEGORIZATION

In addition to section 3 above, the following requirements apply to snubber classification into HSSC and LSSC categories.

4.1 System Risk Categorization

This paragraph establishes requirements for separating systems with snubbers into high and low risk categories.

4.1.1 Importance Measures

(a) As a minimum, two importance measures, F-V and RAW, shall be calculated for those systems modeled in the PRA.

(b) The impact upon CDF, and upon LERF if available, shall be determined.

4.1.2 Screening Criteria. For those systems modeled in the PRA, a threshold value of F-V > 0.05 (system level) or F-V > 0.005 (component or train level) based on CDF (and LERF if available) or RAW > 2 (component or train level) shall be initially considered as high risk components, trains, or systems.

4.1.3 Sensitivity Studies

(a) The following sensitivity studies shall be performed for each system containing snubbers:

(1) For Level 1 PRA (CDF end state), determine system and component importance rankings (F-V and RAW) from internal and external initiating events. If external/seismic initiating event PRA is not available, then use alternative deterministic evaluation (i.e., seismic margins).

(2) If available for Level 2 PRA (LERF end state), determine system and component importance rankings as appropriate from internal and external initiating events. If Level 2 PRA is not available, then use

alternative deterministic evaluation (i.e., containment bypass).

(3) Identify the major components and their contribution to system risk (F-V and RAW), using internal (and external if available) initiating events.

(4) If available for shutdown PRA (CDF end state), determine system and component importance rankings as appropriate from internal and external initiating events. If shutdown PRA is not available, then use alternative deterministic evaluation (i.e., shutdown cooling paths).

(b) The results of these sensitivity studies, and any others that are performed, shall be documented.

(c) The results and insights of these sensitivity studies shall be provided to the Expert Panel for their consideration in the final categorization of the snubbers.

4.1.4 Qualitative Assessments. Qualitative assessments shall be performed for all active IST components (e.g., pumps and valves) protected by snubbers, unless those snubbers are categorized as HSSC.

(a) The following qualitative assessments shall be performed:

(1) impact of initiating events (i.e., the impact of failure or degradation as it might result in an initiator)

(2) potential consequences of shutdown (outage) conditions

(3) response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding, etc.)

(b) Qualitative assessments shall be performed for plant-specific design basis conditions and events not modeled in a PRA.

(c) Qualitative assessments shall consider the impacts upon the plant to

(1) prevent or mitigate accident conditions

(2) reach and/or maintain safe shutdown conditions

(3) preserve the reactor primary coolant pressure boundary integrity

(4) maintain containment integrity

(d) Qualitative assessments shall also consider

(1) safety function being satisfied by the component's operation

(2) level of redundancy existing at the plant to fulfill the component's function

(3) ability to recover from a failure of the component

(4) performance history of the component

(5) plant technical specifications requirements applicable to the component

(6) emergency operating procedure instructions that use the component(s)

(7) design and licensing basis information relevant to IST component function

(e) The cumulative impacts of combinations of component unavailability, which could impact an entire system (e.g., multitrain impacts) or critical safety function (e.g., multisystem impacts), shall also be considered.

(f) These qualitative assessments and the Expert Panel's disposition of them shall be documented so independent parties can review and cognizant analysts who did not take part in the original assessment can confirm the result.

(g) These qualitative assessments shall be available to the Expert Panel for their decision of component safety categorization.

4.2 Snubber Safety Categorization

This paragraph provides requirements for the Expert Panel's review and evaluation process for categorizing snubbers relative to their safety significance, using both deterministic and probabilistic insights.

4.2.1 Expert Panel Utilization. The Expert Panel shall blend deterministic and probabilistic information to classify snubbers into HSSC or LSSC categories using both PRA insights and deterministic insights.

(a) PRA Insights. The results of PRA analyses shall be used by the Expert Panel to determine the safety significance of components (e.g., pumps and valves) within HSSC systems. Information contained in PRAs relative to the role of components in mitigating or preventing core damaging events or large early radiological release events shall be considered.

(b) Quality of PRA. The scope of the PRA and depth of probabilistic analyses shall be assessed, evaluated, and documented. As a minimum, the following shall be documented:

(1) the level of plant-specific PRA analysis available for assessing the applicability of PRA information relative to IST programs. For example, written documentation describing the level of plant-specific PRA analysis such as Level 1 PRA (assessment of core damage frequency) and/or Level 2 PRA (assessment of core damage frequency plus containment performance).

(2) scope of initiating events considered (internal events, external events, both).

(3) typical failure modes considered (e.g., hardware failures, testing/maintenance failures, common cause failures, human errors).

(4) PRA scope for plant configurations (e.g., low power risk, shutdown risk, transition mode risk, at-power risk) reviewed relative to the applicability of PRA information and IST component function(s).

(c) Deterministic Insights. The Expert Panel shall also consider deterministic factors when assessing the safety significance of components within the scope of IST programs (see Nonmandatory Appendix A of Division 1 for a sample list of deterministic considerations).

4.2.2 Expert Panel Requirements

(a) Plant Procedure. An approved plant procedure shall describe the process, including

(1) designated members and alternates

(2) designated chair and alternate
(3) quorum
(4) attendance records
(5) agendas
(6) motions for approval
(7) process for decision making
(8) documentation and resolution of differing opinions
(9) minutes
(10) required training

(b) Training. The Expert Panel shall be trained and indoctrinated in the specific requirements to be used for this Code Case. Training and indoctrination shall include the application of risk analysis methods and techniques used for this Code Case. At a minimum, the risk methods and techniques include

(1) PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty)
(2) use of risk importance measures
(3) assessment of failure modes for snubbers and components being supported by snubbers
(4) reliability versus availability
(5) risk thresholds
(6) expert judgment elicitation

Each of the aforementioned topics shall be covered in the indoctrination to the extent necessary to provide the Expert Panel with a level of knowledge needed to adequately evaluate and approve the scope of the snubber selections, using both probabilistic and deterministic information.

(c) Experience. Requirements shall be established for ensuring adequate experience levels of Expert Panel members. Member experience levels shall be documented and maintained.

(d) Membership

(1) There shall be at least five experts designated as members of the Expert Panel. Members may be experts in more than one field; however, excessive reliance on any one member's judgment shall be avoided.

(2) The chairperson shall be familiar with this Code Case and shall facilitate Expert Panel activities, to ensure that the requirements of this Code Case are satisfied.

(3) Expertise in the following functions shall be represented on the Expert Panel:

(-a) operation
(-b) safety analysis engineering
(-c) probabilistic risk assessment

(4) Additional members of the Expert Panel should be selected who have the following plant expertise:

(-a) systems performance
(-b) maintenance
(-c) licensing
(-d) component performance
(-e) ASME inservice examination and testing for snubbers
(-f) ASME inservice testing for pumps and valves
(-g) quality assurance

(5) Alternate members to the Expert Panel may be designated on a temporary basis; however, vacancies in the Expert Panel membership should be filled by qualified individuals within a reasonable period of time.

(6) Other plant or nuclear industry experts may be invited to attend some or all of the sessions of the Expert Panel as visitors to provide observations, opinions, or recommendations.

4.2.3 Expert Panel Decision Criteria

(a) Level A Inclusion Criteria. Any of the following contributors to snubber importance above stated threshold will potentially make the snubber HSSC:

(1) Level A-1. All snubbers protecting the following components:

(-a) PWRs: steam generators, reactor coolant pumps
(-b) BWRs: recirculation pumps

(2) Level A-2. All snubbers protecting components in systems with PRA importance ranking F-V > 0.05 or, if evaluated on a component/train level, all snubbers supporting the components in trains with PRA importance ranking F-V > 0.005 or RAW > 2.

(b) Level B Exclusion Criteria. The following conditions allow a snubber to potentially be classified as LSSC:

(1) Level B-1. All snubbers that support the component with an importance ranking F-V ≤ 0.005 and a RAW ≤ 2.

(2) Level B-2. All snubbers associated with unmodeled components and associated with components that would likely be unmodeled in Levels 1, 2, 3, and shutdown PRAs, including both internal and external events.

4.2.4 Reconciliation. Decisions of the Expert Panel shall be arrived at by consensus. Differing opinions shall be documented and resolved, if possible. If a resolution cannot be achieved concerning the safety significance classification of a snubber, then the snubber shall be classified HSSC.

5 SPECIFIC REQUIREMENTS FOR SNUBBER SERVICE CONDITION DETERMINATION

All snubbers shall be placed in one of two service conditions, *harsh* or *benign*.

5.1 Harsh

The *harsh* service condition shall be considered for those operating environments where the snubber is exposed to higher temperatures, vibration, or other service condition variables (see section ISTD 8, Nonmandatory Appendix F) that would result in a predicted service life of ≤ 10 yr.

5.2 Benign

The *benign* service condition shall be considered for those operating environments where the snubber is exposed to lower temperatures, minimal vibration, or other service condition variables (see section ISTD 8, Nonmandatory Appendix F) that would result in a predicted service life of >10 yr.

6 SPECIFIC REQUIREMENTS FOR HSSC TESTING STRATEGIES

NOTE: These are alternate examination and testing strategies in lieu of sections ISTD 6 and ISTD 7 requirements in reference (a) in section 9 below.

6.1 Examination and Testing Strategies for HSSC Snubbers in Harsh Environment

(a) All snubbers (size, manufacturer, type) in this category shall be considered as one population for examination and testing.

(b) Perform visual examination per section ISTD 6.

(c) Test per 37% or 10% plan each refueling cycle or 24 months. If a failure occurs, follow the applicable requirements of the selected plan.

(d) Test and/or replace all snubbers within this DTPG once every 6 yr.

(e) The snubbers may be selected for testing on a rotational basis.

6.2 Examination and Testing Strategies for HSSC Snubbers in Benign Environment

(a) All snubbers (size, manufacturer, type) in this category shall be considered as one population for examination and testing.

(b) Perform visual examination per section ISTD 6.

(c) Test per 37% or 10% plan each refueling cycle or 24 months. If a failure occurs, follow the applicable requirements of the selected plan.

(d) Test and/or replace all snubbers within this DTPG once every 10 yr.

(e) The snubbers may be selected for testing on a rotational basis.

7 SPECIFIC REQUIREMENTS FOR LSSC TESTING STRATEGIES

NOTE: These are alternate examination and testing strategies in lieu of sections ISTD 6 and ISTD 7 requirements in reference (a) in section 9 below.

7.1 Examination and Testing Strategies for LSSC Snubbers in Harsh Environment

(a) All snubbers (size, manufacturer, type) in this category shall be considered as one population for examination and testing.

(b) Perform visual examination per section ISTD 6.

(c) Test per 37% or 10% plan each refueling cycle or 24 months. If a failure occurs, follow the applicable requirements of the selected plan.

(d) Test and/or replace all snubbers within this DTPG once every 10 yr.

(e) The snubbers may be selected for testing on a rotational basis.

7.2 Examination and Testing Strategies for LSSC Snubbers in Benign Environment

(a) Determine and monitor service life of each snubber per section ISTD 8.

(b) Perform visual examination of all hydraulic snubbers in this category per section ISTD 6.

(c) Perform visual examination of all mechanical snubbers in this category to satisfy visual examination requirements of para. ISTD 6.3 and verify freedom of motion by manual stroking, measuring incremental thermal movement, or functional testing. Perform visual examination of all mechanical snubbers once every 10 yr, staggered on minimum 10% to 20% every refuel cycle or 24 months. If degradation is found, test the snubber. If the snubber fails, then verify freedom of motion or test all snubbers susceptible to the same failure mode.

8 RECORDS AND REPORTS

In addition to the requirements of reference (a) in section 9 below with respect to records, the following records of the Expert Panel and the component shall be maintained.

8.1 Expert Panel Records

(a) membership and attendance

(b) member expertise representation and training records

(c) member experience (years of experience in each of the expertise categories)

(d) meeting agendas

(e) meeting minutes

(f) plant procedure

8.2 Component Records

(a) risk significance based on PRA importance measures

(b) additional PRA quantitative information

(c) deterministic information

(d) expert Panel categorization decisions of HSSC or LSSC

(e) basis for the HSSC/LSSC decision

9 REFERENCES

(a) ASME OM Code, Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Power Plants, 1995 edition and later addenda

(b) EPRI PSA Applications Guide, TR-105396, August 1995

Code Case OMN-11
Risk-Informed Testing for Motor-Operated Valves

Inquiry: What alternatives may be used for a risk-informed program in lieu of the testing frequency requirements of Code Case OMN-1, para. 3.3 for Inservice Testing of Motor-Operated Valves?

Reply: It is the opinion of the Committee that the following test frequency alternative requirements are an acceptable method of meeting the requirements of OMN-1, paras. 3.3 and 3.7 and may be applied.

1 SAFETY SIGNIFICANCE CATEGORIZATION

Motor-operated valves (MOVs) shall be evaluated and categorized as high safety significant components (HSSCs) or low safety significant components (LSSCs), in accordance with the safety significance categorization methodology prescribed in Code Case OMN-3. The risk evaluation process may identify MOVs that were not previously included within the scope of OMN-1 but are applicable under a risk-informed program.

2 HSSC INSERVICE TESTING

HSSC MOVs shall be tested in accordance with OMN-1, para. 3.3, using established test frequencies and utilizing a mix of static and dynamic MOV performance testing.

3 LSSC INSERVICE TESTING

(a) LSSC grouping shall be technically justified, but need not comply with all the requirements of OMN-1, para. 3.5.

(b) LSSC MOVs shall be associated with an established group of other MOVs wherever possible. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with OMN-1, section 6, and applied to all LSSCs associated with that group.

(c) LSSC MOVs that are not able to be associated with an established group, shall be inservice tested in accordance with OMN-1, para. 3.3, using an initial test frequency of three refueling cycles or 5 yr (whichever is longer) until sufficient data exist to determine a more appropriate test frequency.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with OMN-1, subpara. 3.3.1(c).

Code Case OMN-12
Alternate Requirements for Inservice Testing Using Risk Insights for Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants (OM Code-1998, Subsection ISTC)

Inquiry: What alternative to the requirements of paras. ISTC-5130 and ISTC-5140 may be used for risk-informed inservice testing of pneumatically and hydraulically operated valve assemblies?

Reply: It is the opinion of the Committee that the following alternative requirements may be used in lieu of paras. ISTC-5130 and ISTC-5140 for risk-informed inservice testing of pneumatically and hydraulically operated valve assemblies.

1 INTRODUCTION

This Code Case establishes alternative requirements for implementing and maintaining a risk-informed inservice testing program for active pneumatically and hydraulically operated valve assemblies in light-water reactor power plants.

2 TERMS AND DEFINITIONS

The following are provided to ensure a uniform understanding of select terms used in this Code Case.

baseline data: one or more values of test parameters measured or determined when the equipment is known to be operating acceptably at conditions including design basis conditions.

baseline test: a performance test to establish baseline data.

bench set: calibration of the actuator spring range to account for the in-service process forces.

critical parameters: one or more specific parameters that must be met for a valve assembly to meet its design function.

design basis conditions: conditions associated with design basis events, as specified in the final safety analysis report or design basis document(s).

dynamic test: a test conducted with system pressure and/or flow.

hydraulic actuator: a device that provides energy to open, close, or position a valve via hydraulic pressure.

hydraulically operated valve assembly (or *valve assembly):* a valve and its associated hydraulic actuator, including all subcomponents required for the valve assembly to perform its intended safety function.

maximum available pneumatic pressure: the maximum pressure available to the actuator.

performance test: a test to determine whether a system, structure, or component meets specified acceptance criteria.

periodic valve assembly exercising: periodic stroking of the valve assembly to ensure that the valve assembly is not binding and the valve actuator is functional.

pneumatic actuator: a device that provides energy to open, close, or position a valve via pneumatic pressure.

pneumatically operated valve assembly (or *valve assembly):* a valve and its associated pneumatic actuator, including all subcomponents required for the valve assembly to perform its intended safety function(s).

seat load: the total net contact force between the obturator and the seat under static conditions.

set points: a point or set of points that are set so that a valve assembly would meet its design function. Examples of set point would be bench set values, or pressure regulator values.

setup: the establishment and adjustment (i.e., bench set, seat load, regulator set point) of valve subcomponents so that a valve will perform its function(s).

spring rate: the force change per unit change in length, usually expressed as pounds per inch (lb/in.) or newtons per millimeter (N/mm).

total friction: the sum of packing friction, valve internal friction, and actuator friction.

valve assembly group: a collection of valve assemblies having similar design characteristics, applications, and service conditions so that test results, design evaluations, and operating experiences from one member may be applied to other members of the group.

3 PREREQUISITES

3.1 Classification

Valve assemblies shall be classified as either high safety significant or low safety significant in accordance with Code Case OMN-3.

3.2 Grouping of Valve Assemblies

Grouping of valve assemblies is permissible. Valve assemblies with identical or similar designs and with similar plant service conditions may be grouped together. The following shall be performed if grouping of valve assemblies is used:

(a) grouping valve assemblies shall be justified by a documented engineering evaluation.

(b) the functionality of all valve assembly groups shall be validated by the appropriate inservice testing of one or more representative valve assemblies.

(c) test results shall be evaluated and justified for all valve assemblies in a group.

(d) a single representative valve assembly shall not be selected for inservice testing consecutively. All testable valve assemblies in a group shall be inservice tested before a previously tested representative valve assembly can be selected. In addition to this requirement, the owner may elect to consecutively test a certain valve assembly to monitor changes in its functional margin over time.

(e) the number of valve assemblies tested from each group shall be determined using appropriate statistical methodology.

(f) test results for the representative valve assembly shall be analyzed and evaluated for each valve assembly in the group.

3.3 Testing Basis

An analysis of the test, maintenance, and operating history of a valve assembly, or valve assembly group, shall be performed and documented in order to establish the basis for specifying testing requirements and frequency.

4 HIGH SAFETY SIGNIFICANT VALVE ASSEMBLIES

The purpose of the combination of testing and/or analysis is to ensure the capability of the valve assembly to perform its intended safety function. Testing of valve assemblies classified as high safety significant shall meet the requirements of paras. 4.1 through 4.5.

4.1 Design Verification

4.1.1 The design basis capability for existing valve assemblies shall be verified prior to implementing this Code Case for those valve assemblies.

4.1.2 The design basis capability for new valve assemblies shall be verified prior to initially being placed in service.

4.1.3 A baseline test in combination with at least one of the following shall be performed to demonstrate design basis capability of the valve assembly:

(a) dynamic test at design basis conditions

(b) correlation with a similar valve assembly that has been dynamically tested at similar or bounding conditions

(c) extrapolation of results of dynamic tests at highest practicable test conditions

(d) calculation methods

4.2 Inservice Test Requirements

4.2.1 Baseline Test Requirements

4.2.1.1 Valve assemblies shall have a baseline test to establish reference values for comparison to subsequent periodic performance test data.

4.2.1.2 The preservice test results may be used as the baseline test, provided the test conditions in para. 4.3.1 are satisfied. Testing in accordance with ISTC-3100 may be used as the baseline test.

4.2.2 Periodic Test Requirements

4.2.2.1 Periodic test frequency shall be determined based on analysis of data. Data analysis shall be in accordance with para. 4.4.

4.2.2.2 If insufficient data exist to determine the inservice test frequency in accordance with para. 4.4, the valve assembly inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist to determine a more appropriate test frequency.

4.2.2.3 The maximum interval between inservice tests shall not exceed 10 yr.

4.2.2.4 Periodic test methods shall be in accordance with para. 4.3.

4.2.3 Periodic Valve Assembly Exercising

4.2.3.1 Once during each fuel cycle of operation, each valve assembly subject to this Code Case shall be operated to move the obturator through one full stroke (open and close). If a valve assembly experiences a full stroke during the fuel cycle of operation, and the Owner elects to document such operation, no additional valve operation is required to satisfy this requirement.

4.2.3.2 More frequent exercise requirements for valve assemblies with higher risk significance, adverse or harsh environmental conditions, or with abnormal performance history shall be considered. Alternatively, longer exercise intervals may be used if justified by successful operating experience.

4.2.3.3 Paragraph 4.2.3 does not limit the plant operating mode under which periodic valve assembly exercising may be performed.

4.3 Test Methods

The following test methods shall be applied to valve assemblies determined to be subject to this Code Case. The Owner is responsible for establishing conformance with the test methods, including off-site testing.

4.3.1 Test Conditions. Tests shall be performed without any changes, modifications, or adjustments to the valve assembly during testing. Test conditions that apply to valve assemblies based on the selection of the test parameters in accordance with para. 4.3.3 shall be determined. The baseline test shall be performed at specific repeatable conditions. The periodic performance tests shall be performed at the conditions used to establish baseline values.

4.3.2 Test Procedures. Procedures shall be established, as appropriate, to provide for the following:

(a) methodical, repeatable, and consistent performance testing

(b) valid test data that are not influenced by any preconditioning associated with performance testing procedural steps

(c) data that reflects, or can be correlated with, the design basis conditions

(d) adequate data for analysis and evaluation per para. 4.4

4.3.3 Test Parameters

4.3.3.1 Test parameters shall be monitored to ensure that the valve assembly performs its intended safety function(s). The safety function(s) may include one or more of the following:

(a) open within a specified minimum or maximum time period, or both

(b) close within a specified minimum or maximum time period, or both

(c) stroke open to obtain specified flow or pressure

(d) stroke open or closed against flow or pressure, including maximum differential pressure for the valve assembly to fulfill its safety function, across the valve

(e) travel to a predetermined intermediate position

(f) remain in operating position for specified period of time

(g) operate a specified number of cycles

4.3.3.2 Determine which of the following parameters, or combination of parameters, which may be determined from data obtained during testing, are important to monitor to ensure the safety function(s) capability of the valve assembly:

(a) bench set

(b) seat load

(c) spring rate

(d) full-stroke time

(e) actual travel

(f) total friction

(g) maximum available pneumatic pressure

(h) minimum pneumatic pressure required to accomplish the safety function(s) of the valve assembly

(i) hydraulic pressure at an appropriate point in operation

(j) pneumatic and hydraulic fluid condition and cleanliness

(k) set point of pressure switch, relief valve, regulator, etc.

(l) torque

(m) others as applicable

4.3.4 Test Information. Test information shall be recorded in accordance with section ISTC-9000. In addition, the following information shall be recorded:

(a) test conditions per para. 4.3.1, including system fluid and ambient conditions

(b) remarks concerning abnormal or erratic action, either during or preceding performance testing

(c) date of test

(d) valve assembly identification

(e) nameplate data

(f) test equipment identification and date of calibration

(g) parameters measured in accordance with para. 4.3.3.2

(h) name of tester

4.4 Analysis and Evaluation of Data

The following analysis and evaluation of data shall be applied to valve assemblies determined to be subject to this Code Case.

4.4.1 Acceptance Criteria. Acceptance criteria shall be established by which test data shall be analyzed. The criteria shall specify the acceptable limits or range of test parameters based on design criteria necessary for the valve assembly to perform its intended safety function(s) until the next test.

4.4.2 Analysis of Data. Data obtained from a test performed under this Code Case shall be analyzed to determine acceptable valve assembly performance.

Performance test data shall be compared to parameter limits or ranges established in accordance with para. 4.4.1. Test history (such as degradation) shall be considered on a particular valve assembly. Performance test data trends (including allowance for uncertainties) shall be established to predict when data points may approach the parameter limits. If a datum being compared falls within the acceptable range of established parameters, the valve assembly may be considered acceptable. If the test data is unacceptable, corrective actions shall be taken in accordance with para. 4.5.

4.4.3 Evaluation of Data

4.4.3.1 Criteria for data evaluation shall be established that ensures

(a) the valve assembly meets its established acceptance criteria

(b) corrective action is taken as described in para. 4.5 if a valve assembly does not meet its established acceptance criteria

(c) validation of the test frequency

4.4.3.2 Where grouping is used, the results of data evaluation shall be applied to all valve assemblies in the group.

4.4.4 Documentation of Analysis and Evaluation of Data. Results of test data evaluation and analysis shall be documented. Documentation shall include

(a) assumptions made

(b) values of test parameters and test information established in accordance with paras. 4.3.4 and 4.4.1

(c) a statement that test data are within acceptable limits or that corrective actions have been initiated and that independent verification of the test data evaluation and analysis has been completed

(d) a summary of data analysis and evaluation in accordance with paras. 4.4.2 and 4.4.3

4.5 Corrective Action

If the monitored parameters are outside acceptable limits, then corrective action shall be initiated. If acceptance criteria (established in para. 4.4.1) limiting values are exceeded, the valve shall immediately be declared inoperable. Valve assemblies declared inoperable may be repaired or replaced, or the data may be analyzed to determine the cause of the deviation and to show the valve assembly to be operating acceptably.

The corrective action shall bring the valve assembly back into compliance with the acceptance criteria. When the corrective action consists of evaluating the acceptability of the valve assembly at the degraded conditions, new baseline data and acceptance criteria shall be established. The valve assembly shall be retested in accordance with para. 4.3 following the corrective action and prior to return to service. The cause of the failure or degradation shall be evaluated for identification of corrective actions to prevent recurrence in similar components or grouped valve assemblies. Documentation of corrective actions shall include

(a) valve assembly identification

(b) summary of corrective action and results

(c) subsequent test data or analysis, including analysis for valve assembly operability

(d) identification of the cause of the anomaly and technical justification for corrective action taken

(e) description of actions taken to restore operational readiness of the valve assembly

5 LOW SAFETY SIGNIFICANT VALVE ASSEMBLIES

The purpose of this section is to provide a high degree of confidence that the LSSC valve assemblies will perform their intended safety function if called upon. Valve assemblies classified as LSSC shall meet the requirements of paras. 5.1 through 5.6.

5.1 Set Points and/or Critical Parameters

5.1.1 Set points and/or critical parameters for existing valve assemblies shall be established prior to implementing this Code Case for those valve assemblies.

5.1.2 Set points and/or critical parameters for new valve assemblies shall be established prior to initially being placed in service.

5.1.3 Establishment of set points and/or critical parameters should consider the following:

(a) walk down of the valve assembly to establish that the installed assembly agrees with the plant's information or database

(b) original manufacturer's set points

(c) changes to the original plant system design parameters or the operation of the valve assembly

(d) industry experience

(e) maximum expected packing and other valve assembly friction

(f) manufacturer's or industry calculations may be used to establish set points and/or critical parameters

5.1.4 All information and methods used to establish the set points and/or critical parameters shall be documented.

5.2 Evaluation Requirements

Procedures shall be established, as appropriate, and should consider the following:

(a) consistent and verifiable evaluation of the valve assembly

(b) application of diagnostic test equipment

(c) documentation of parameters necessary to evaluate the valve assembly's ability to perform its intended safety function(s)

(d) system or plant conditions, at which the valve assembly is tested, shall be evaluated

(e) which of the parameters, or combination of parameters, listed in para. 4.3.3.2 are important to monitor to provide a high degree of confidence in the capability of the valve assembly to perform its safety function

5.3 Periodic Evaluation

5.3.1 Periodic Evaluation Frequency. Periodic evaluation frequency shall be established based on the requirements of paras. 5.3.1.1 through 5.3.1.3.

5.3.1.1 No valve assembly shall exceed 10 yr between evaluations.

5.3.1.2 The initial evaluation period shall be established based on one or more of the following:

(a) plant-specific maintenance and operating history

(b) evaluation of nonmetallic materials required for safety function(s) of the valve assembly

(c) manufacturer's recommendations

(d) if a subcomponent has no effect on the setup of the valve's safety function, it need not be considered in the evaluation period of the overall valve assembly

5.3.1.3 All information and methods used to establish the evaluation period shall be documented.

5.3.2 Extending or Decreasing Periodic Evaluation Periods

5.3.2.1 The initial evaluation period and subsequent periods may be extended 1 yr or one refueling cycle at a time if the evaluation of valve assembly test data has determined that there is no unacceptable degradation of components in the valve assembly.

5.3.2.2 The periodic evaluation period shall be decreased if it is determined that a component failure was due to degradation during the existing evaluation period.

5.3.3 Group Evaluation Period. Where grouping of valve assemblies is used, all valves in a group shall be assigned the same periodic evaluation period.

5.4 Evaluations

5.4.1 Initial or As-Left Evaluation

5.4.1.1 The initial or as-left evaluation shall be performed after the valve assembly is initially put in service, postmaintenance, or refurbished and has been set up per the established criteria. The purpose of this evaluation is to

(a) validate the assumptions used to establish the valve assembly's set-up criteria used in para. 5.1

(b) confirm the integrity and operation of all the valve assembly's subcomponents

5.4.1.2 If a valve assembly's evaluation does not meet the parameters established in para. 5.1, corrective action shall be initiated.

5.4.2 As-Found Evaluation. Maintenance and operational activities shall be conducted in order to prevent or minimize preconditioning of the valve assembly prior to as-found evaluation.

5.4.2.1 An as-found evaluation shall be performed to

(a) validate any assumptions used in para. 5.1

(b) confirm the integrity of the valve assembly's subcomponents

5.4.2.2 As-found evaluations shall be performed on a valve assembly prior to any refurbishment at the end of a periodic evaluation period.

5.4.2.3 If a valve assembly's evaluation does not meet the parameters established in para. 5.1, corrective action shall be initiated.

5.5 Periodic Valve Assembly Exercising

5.5.1 Once during each fuel cycle of operation, each valve assembly subject to this Code Case shall be operated to move the obturator through one full stroke (open and close).

5.5.2 If a valve assembly experiences a full stroke during the plant's cycle of operation and the Owner elects to document such operation, no additional operation is required for the cycle.

5.5.3 Paragraph 5.3 does not limit the plant's operating mode under which periodic valve assembly exercising may be performed.

5.6 Corrective Action

5.6.1 If the parameters monitored and evaluated do not meet the established criteria, then corrective action shall be initiated.

5.6.2 If a valve assembly being evaluated for corrective action is part of a group of valve assemblies, the group must also be evaluated for corrective action.

Code Case OMN-13
Requirements for Extending Snubber Inservice Visual Examination Interval at LWR Power Plants

Inquiry: With the low rate of problem identification through the visual examination process, can the visual examination interval allowed in Table ISTD 6.5.2-1 of the OM Code, Subsection ISTD, 1995 Edition through 1996 Addenda be extended?

Reply: Yes, provided that the following additional service life monitoring requirements are met.

Applicability: ASME OM Code-1995 Edition with 1996 Addenda and later editions and addenda.

1 APPLICABILITY

This Code Case establishes specific requirements that must be met in order to allow extension of the visual examination interval beyond the maximum interval allowed in Table ISTD 6.5.2-1 for mechanical and hydraulic snubbers. Paragraphs referenced in this Code Case denote the 1995 Edition and 1996 Addenda. A correlation table (Table 1) is provided for the 1998 Edition.

2 GENERAL REQUIREMENTS

The following requirements shall be implemented in order to extend the visual examination interval beyond the maximum interval allowed in Table ISTD 6.5.2-1:

(a) These requirements are in addition to the service life monitoring requirements in section ISTD 8.

(b) The requirements of this Code Case shall be implemented after the requirements of para. ISTD 6.5.1 and subparas. ISTD 6.5.2(a) through ISTD 6.5.2(c) have been satisfied and the previous examination per Table ISTD 6.5.2-1 was performed at a maximum interval of two fuel cycles.

(c) Demonstrate that the requirements of paras. 3.1 through 3.6 of this Code Case have been met for one interval prior to extending the examination interval.

2.1 Service Life Evaluations

The data and information gathered under this Code Case shall be utilized to reevaluate service life as described in section ISTD 8.

2.2 Testing for This Code Case

Snubbers tested specifically for this Code Case shall be dispositioned per para. ISTD 8.5.

Table 1 Correlation Table

1995 Edition and 1996 Addenda	1998 Edition
ISTD 1.13	ISTD-1750
ISTD 6	ISTD-4200
ISTD 6.1, 6.2, 6.3, 6.4	ISTD-4210, 4220, 4230, 4240
IST 6.5.1	ISTD-4251
ISTD 6.5.2(a)	ISTD-4252(a)
ISTD 6.5.2(b)	ISTD-4252(b)
ISTD 6.5.2(c)	ISTD-4252(c)
ISTD 8	ISTD-6000
ISTD 8.5	ISTD-6500
Table ISTD 6.5.2-1	Table ISTD-4252-1

3 SPECIFIC REQUIREMENTS

3.1 Examination for Indications of Degradation or Severe Operating Environments

Examinations per paras. ISTD 6.1 through ISTD 6.4 shall include examination for indications of degradation and severe operating environments.

3.2 Examination Prior to Maintenance or Testing

All snubbers shall be examined in accordance with the requirements of paras. ISTD 6.1 through ISTD 6.4 and para. 3.1 of this Code Case prior to conducting any maintenance, stroking, or testing, and prior to removal, for any reason, from their installed location.

3.3 Monitoring of Reservoir Fluid Level

Fluid level in hydraulic snubber reservoirs shall be sufficient to ensure that the snubber is acceptable for continued service to the next examination interval.

3.4 Review of Operational Readiness Test Data

All inservice test data acquired since implementation of the requirements of this Code Case shall be evaluated for indications of snubber degradation or other anomalies. This includes a review of test traces, where available. The results of this evaluation shall be used

(a) to identify snubbers that are subject to progressive degradation

(b) to identify severe operating environments not previously identified

Where applicable, data gathered prior to implementation of this Code Case shall also be evaluated.

3.5 Examination During Disassembly

Snubbers and snubber parts shall be examined for indications of degradation and severe operating environments during disassembly (e.g., during failure evaluation, refurbishment).

3.6 Transient Dynamic Event

The service life evaluation required by para. 2.1 of this Code Case shall include any transient dynamic event and actions taken under para. ISTD 1.13.

3.7 Frequency of Examinations

All snubbers within the scope of Subsection ISTD shall be examined and evaluated per paras. ISTD 6.1, ISTD 6.3, and ISTD 6.4 at least once every 10 yr.

Code Case OMN-13, Revision 1
Requirements for Extending Snubber Inservice Visual Examination Interval at LWR Power Plants

Inquiry: With the low rate of problem identification through the visual examination process, can the visual examination interval allowed in Table ISTD-4252-1 of the OM Code, Subsection ISTD, 1995 Edition through 2006 Addenda be extended?

Reply: Yes, provided that the following additional service life monitoring requirements are met.

Applicability: ASME OM Code-1995 Edition through 2006 Addenda.

1 APPLICABILITY

This Code Case establishes specific requirements that must be met in order to allow extension of the visual examination interval beyond the maximum interval allowed in Table ISTD-4252-1 for mechanical and hydraulic snubbers. Paragraphs referenced in this Code Case denote the 1998 Edition through the 2006 Addenda. A correlation table (Table 1) is provided for the 1995 Edition. This Code Case supersedes the previously published version.

2 GENERAL REQUIREMENTS

The following requirements shall be implemented in order to extend the visual examination interval beyond the maximum interval allowed in Table ISTD-4252-1:

(a) These requirements are in addition to the service life monitoring requirements in section ISTD-6000.

(b) The requirements of this Code Case shall be implemented after the requirements of paras. ISTD-4251 and ISTD-4252 have been satisfied and the previous examination per Table ISTD-4252-1 was performed at a maximum interval of two fuel cycles.

(c) Demonstrate that the requirements of paras. 3.1 through 3.6 of this Code Case have been met for one interval prior to extending the examination interval.

2.1 Service Life Evaluations

The data and information gathered under this Code Case shall be utilized to reevaluate service life as described in section ISTD-6000.

2.2 Testing for This Code Case

Snubbers tested specifically for this Code Case shall be dispositioned per para. ISTD-6500.

Table 1 Correlation Table

1995 Edition and 1996 Addenda	1998 Edition Through 2006 Addenda
ISTD 1.13	ISTD-1750
ISTD 6	ISTD-4200
ISTD 6.1, 6.2, 6.3, 6.4	ISTD-4210, 4220, 4230, 4240
ISTD 6.5.1	ISTD-4251
ISTD 6.5.2	ISTD-4252
ISTD 8	ISTD-6000
ISTD 8.5	ISTD-6500
Table ISTD 6.5.2-1	Table ISTD-4252-1

3 SPECIFIC REQUIREMENTS

3.1 Examination for Indications of Degradation or Severe Operating Environments

Examinations per paras. ISTD-4210, ISTD-4220, ISTD-4230, and ISTD-4240 shall include examination for indications of degradation and severe operating environments.

3.2 Examination Prior to Maintenance or Testing

All snubbers shall be examined in accordance with the requirements of paras. ISTD-4210, ISTD-4220, ISTD-4230, and ISTD-4240 and para. 3.1 of this Code Case prior to conducting any maintenance, stroking, or testing, and prior to removal, for any reason, from their installed location.

3.3 Monitoring of Reservoir Fluid Level

Fluid level in hydraulic snubber reservoirs shall be sufficient to ensure that the snubber is acceptable for continued service to the next examination interval.

3.4 Review of Operational Readiness Test Data

All inservice test data acquired since implementation of the requirements of this Code Case shall be evaluated for indications of snubber degradation or other anomalies. This includes a review of test traces, where available. The results of this evaluation shall be used

(a) to identify snubbers that are subject to progressive degradation

(b) to identify severe operating environments not previously identified

Where applicable, data gathered prior to implementation of this Code Case shall also be evaluated.

3.5 Examination During Disassembly

Snubbers and snubber parts shall be examined for indications of degradation and severe operating environments during disassembly (e.g., during failure evaluation, refurbishment).

3.6 Transient Dynamic Event

The service life evaluation required by para. 2.1 of this Code Case shall include any transient dynamic event and actions taken under para. ISTD-1750.

3.7 Frequency of Examinations

(a) All snubbers within the scope of Subsection ISTD shall be examined and evaluated per this Code Case at least once every 10 yr.

(b) If at any time during an examination interval the cumulative number of unacceptable snubbers exceeds the applicable value from Column B in Table ISTD-4252-1, the current examination interval shall end, and all remaining examinations must be completed within the current fuel cycle. The duration of the subsequent examination interval shall be reduced in accordance with Table ISTD-4252-1, using the examination interval prior to implementing the code case as the base interval. The beginning of the subsequent fuel cycle shall be the starting date for the new examination interval.

3.8 Examination Corrective Action

The following actions shall be taken for snubbers that do not meet examination requirements:

(a) An evaluation shall be conducted to determine the cause of the unacceptability.

(b) Unacceptable snubbers shall be adjusted, repaired, modified, or replaced.

Code Case OMN-13, Revision 2
Performance-Based Requirements for Extending Snubber Inservice Visual Examination Interval at LWR Power Plants

Inquiry: With the low rate of problem identification through the visual examination process, can the visual examination interval allowed in Table ISTD-4252-1 of the OM Code, Subsection ISTD, 1995 Edition through 2011 Addenda be extended?

Reply: Yes, provided that the following additional service life monitoring requirements are met.

Applicability: ASME OM Code-1995 Edition through 2011 Addenda.

1 APPLICABILITY

This Code Case establishes specific requirements that must be met in order to allow extension of the visual examination interval beyond the maximum interval allowed in Table ISTD-4252-1 for mechanical and hydraulic snubbers. Paragraphs referenced in this Code Case denote the 1998 Edition through the 2011 Addenda. A correlation table (Table 1) is provided for the 1995 Edition. This Code Case supersedes the previously published version.

2 GENERAL REQUIREMENTS

The following requirements shall be implemented in order to extend the visual examination interval beyond the maximum interval allowed in Table ISTD-4252-1:

(a) These requirements are in addition to the service life monitoring requirements in section ISTD-6000.

(b) The requirements of this Code Case shall be implemented after the requirements of paras. ISTD-4251 and ISTD-4252 have been satisfied and the previous examination per Table ISTD-4252-1 was performed at a maximum interval of two fuel cycles.

(c) Demonstrate that the requirements of paras. 3.1 through 3.6 of this Code Case have been met for one interval prior to extending the examination interval.

2.1 Service Life Evaluations

The data and information gathered under this Code Case shall be utilized to reevaluate service life as described in section ISTD-6000.

2.2 Testing for This Code Case

Snubbers tested specifically for this Code Case shall be dispositioned per para. ISTD-6500.

Table 1 Correlation Table (15)

1995 Edition and 1996 Addenda	1998 Edition Through 2011 Addenda
ISTD 1.13	ISTD-1750
ISTD 6	ISTD-4200
ISTD 6.1, 6.2, 6.3, 6.4	ISTD-4210, 4220, 4230, 4240
ISTD 6.5.1	ISTD-4251
ISTD 6.5.2	ISTD-4252
ISTD 8	ISTD-6000
ISTD 8.5	ISTD-6500
Table ISTD 6.5.2-1	Table ISTD-4252-1

3 SPECIFIC REQUIREMENTS

3.1 Examination for Indications of Degradation or Severe Operating Environments

Examinations per paras. ISTD-4210, ISTD-4220, ISTD-4230, and ISTD-4240 shall include examination for indications of degradation and severe operating environments.

3.2 Examination Prior to Maintenance or Testing

All snubbers shall be examined in accordance with the requirements of paras. ISTD-4210, ISTD-4220, ISTD-4230, and ISTD-4240 and para. 3.1 of this Code Case prior to conducting any maintenance, stroking, or testing, and prior to removal, for any reason, from their installed location.

3.3 Monitoring of Reservoir Fluid Level

Fluid level in hydraulic snubber reservoirs shall be sufficient to ensure that the snubber is acceptable for continued service to the next examination interval.

3.4 Review of Operational Readiness Test Data

All inservice test data acquired since implementation of the requirements of this Code Case shall be evaluated for indications of snubber degradation or other anomalies. This includes a review of test traces, where available. The results of this evaluation shall be used

(a) to identify snubbers that are subject to progressive degradation

(b) to identify severe operating environments not previously identified

Where applicable, data gathered prior to implementation of this Code Case shall also be evaluated.

3.5 Examination During Disassembly

Snubbers and snubber parts shall be examined for indications of degradation and severe operating environments during disassembly (e.g., during failure evaluation, refurbishment).

3.6 Transient Dynamic Event

The service life evaluation required by para. 2.1 of this Code Case shall include any transient dynamic event and actions taken under para. ISTD-1750.

3.7 Frequency of Examinations

(a) All snubbers within the scope of Subsection ISTD shall be examined and evaluated per this Code Case at least once every 10 yr.

(b) If at any time during an examination interval the cumulative number of unacceptable snubbers exceeds the applicable value from Column B in Table ISTD-4252-1, the current examination interval shall end, and all remaining examinations must be completed within the current fuel cycle. The duration of the subsequent examination interval shall be reduced in accordance with Table ISTD-4252-1, using the examination interval prior to implementing the code case as the base interval. The beginning of the subsequent fuel cycle shall be the starting date for the new examination interval.

3.8 Examination Corrective Action

The following actions shall be taken for snubbers that do not meet examination requirements:

(a) An evaluation shall be conducted to determine the cause of the unacceptability.

(b) Unacceptable snubbers shall be adjusted, repaired, modified, or replaced.

Code Case OMN-15
Requirements for Extending the Snubber Operational Readiness Testing Interval at LWR Power Plants

Inquiry: What alternative rules may be used in place of those specified in section ISTD 7 and para. ISTD 7.4 of the 1995 Edition and paras. ISTD-5200 and ISTD-5240 of the 1998 and later editions of the ASME OM Code, which require operational readiness testing during each fuel cycle?

Reply: It is the opinion of the Committee that the test interval requiring operational testing during each fuel cycle specified in section ISTD 7 and para. ISTD 7.4 of the 1995 Edition and paras. ISTD-5200 and ISTD-5240 of the 1998 and later editions of the ASME OM Code may be extended to two or more fuel cycles based on previous satisfactory operational readiness testing, provided that the following requirements are met.

1 APPLICABILITY

This Code Case establishes requirements for extending the test interval specified in section ISTD 7 and para. ISTD 7.4 of the 1995 Edition of the ASME OM Code and paras. ISTD-5200 and ISTD-5240 of the 1998 and later editions and addenda of the ASME OM Code.

2 DEFINITIONS

extended test interval: interval greater than one fuel cycle.

successful campaign: campaign completed without having to test the entire population.

test campaign: the series of actions required to complete the test plan requirements defined in section ISTD 7 or para. ISTD-5200, as applicable.

3 GENERAL REQUIREMENTS AND LIMITATIONS

This Code Case may be used for one or more DTPG (Defined Test Plan Group) during a given test campaign.

This Code Case may not be used for DTPGs defined in para. ISTD 7.5.3, 1995 Edition of the ASME OM Code and para. ISTD-5253 of the 1998 and later editions.

The test interval may be extended by a maximum of one fuel cycle beyond the previous interval.

The maximum allowable test interval shall be three fuel cycles plus 60 days.

4 SPECIFIC REQUIREMENTS

For the test campaign immediately preceding an extended test interval, the initial sample size shall be as indicated in Table 1, Column A (rounded up to the next integer) in lieu of the initial sample size listed in para. ISTD 7.9.1, ISTD 7.12.1, ISTD-5311, or ISTD-5411, as applicable. Testing shall satisfy the applicable mathematical expression listed in Table 1, Column B in lieu of equations listed in para. ISTD 7.11.1, ISTD 7.14.1, ISTD-5331, or ISTD-5431, as applicable.

4.1 Additional Specific Requirements for Implementing a Two Fuel Cycle Test Interval

Prior to implementing a two fuel cycle test interval, three successive test campaigns shall be successfully completed for the applicable DTPG. These shall include the campaign conducted at the end of the fuel cycle immediately preceding the two cycle test interval.

4.2 Additional Specific Requirements for Implementing a Three Fuel Cycle Interval

Prior to implementing a three fuel cycle test interval, the following requirements shall be met:

(a) The test interval immediately preceding the three fuel cycle test interval shall be a two fuel cycle test interval.

(b) The four test campaigns immediately preceding the three fuel cycle test interval shall have been completed successfully.

Table 1 Test Plan Required for Test Campaign Immediately Preceding Extended Interval

Test Plan [Note (1)]	DTPG Size, n	Column A Initial Sample Size [Note (2)]	Column B Mathematical Expression to Be Satisfied
1	$n \geq 370$	52	$N \geq 51.60 + 21.03C$
2	$369 \geq n \geq 300$	$0.13n$	$N \geq 0.13n + C(0.1n)$
3	$299 \geq n \geq 250$	$0.14n$	$N \geq 0.14n + C(0.1n)$
4	$249 \geq n \geq 200$	$0.15n$	$N \geq 0.15n + C(0.1n)$
5	$199 \geq n \geq 150$	$0.18n$	$N \geq 0.18n + C(0.1n)$
6	$149 \geq n \geq 100$	$0.125n$	$N \geq 0.125n + C(0.125n)$
7	$n < 100$	13	$N \geq 12.5 + 12.5C$

GENERAL NOTES:

(a) Definitions of terms:

C = total number of unacceptable snubbers found in the DTPG
N = total number of snubbers tested that were selected from the DTPG
n = number of snubbers in the DTPG

(b) The requirements specified in Table 1 need only apply to the test campaign immediately preceding an extended test interval. For other campaigns, the requirements of Table 1 or the requirements of subpara. ISTD-5331(a) or ISTD-5341(a) shall be met.

NOTES:

(1) Alternatively, Test Plan 1 may be used for DTPG sizes less than 370 snubbers.

(2) Fractional sample values shall be rounded up to the next integer.

Nonmandatory Appendix A
Example Scenarios

This Nonmandatory Appendix provides examples of various scenarios where the snubber inservice test (IST) interval specified in the ASME OM Code may or may not be extended. While it is related to Code Case OMN-15, it is not part of that Code Case. Definitions of terms not defined in this Nonmandatory Appendix are included in Code Case OMN-15 or in the editions/addenda of the ASME OM Code to which it applies.

NOTE: Test plan numbers referred to in this Nonmandatory Appendix are defined in Table 1 of OMN-15.

A-1 SCENARIO 1

DTPG 3 at Plant X has a total of 298 snubbers. A successful test campaign was completed during RFO 5 using the 10% Plan. A successful test campaign was completed during RFO 6 using the 37 Snubber Plan. What is required in order to bypass a test campaign at RFO 8?

Response: Completion of a successful test campaign at RFO 7 using either Test Plan 1 or Test Plan 3.

A-2 SCENARIO 2

Following Scenario 1 for DTPG 3 at Plant X, a test campaign was bypassed at RFO 8. What is required in order to bypass a test campaign at RFO 10 and RFO 11?

Response: Completion of a successful test campaign at RFO 9 using either Test Plan 1 or Test Plan 3.

A-3 SCENARIO 3

DTPG 3 at Plant X has a total of 298 snubbers. Successful test campaigns were completed during RFO 5, 6, 7, and 8. A successful test campaign was completed during RFO 9 using Test Plan 1. Is a test campaign required at RFO 10?

Response: No.

Is a test campaign required at RFO 11?

Response: Yes. The test interval may be extended by a maximum of one fuel cycle beyond the previous interval.

Code Case OMN-15, Revision 2
Performance-Based Requirements for Extending the Snubber Operational Readiness Testing Interval at LWR Power Plants

Inquiry: What alternative rules may be used in place of those specified in paras. ISTD-5200 and ISTD-5240 of the 1998 through 2009 edition of the ASME OM Code that require operational readiness testing during each fuel cycle using test plans described in paras. ISTD-5260, ISTD-5300, and ISTD-5400?

Reply: It is the opinion of the Committee that the test requirement of every fuel cycle, specified in paras. ISTD-5200 and ISTD-5240 of the 1998 through 2009 edition of the ASME OM Code, may be extended to two or more fuel cycles based on the satisfactory results of previous interval tests, provided that the following requirements are met.

1 APPLICABILITY

This Code Case establishes conditions for extending the test requirement specified in paras. ISTD-5200 and ISTD-5240 and replacing the test plans specified in paras. ISTD-5260, ISTD-5300, and ISTD-5400 of the 1998 through 2009 edition of the ASME OM Code.

2 SUPPLEMENTAL DEFINITIONS

extended test interval: interval greater than one fuel cycle.

failure rate: the number of unacceptable required operational readiness tests as a percentage of the total number of required tests performed within a defined test plan group (DTPG) for a completed test campaign.

fuel cycle: time period beginning with the start of the reactor until the completion of the next refuel outage and subsequent restart.

successful test campaign: campaign completed without having to test the entire defined test plan group (DTPG) population.

test campaign: the series of actions required to complete the test plan requirements defined in para. ISTD-5200 during each fuel cycle, or the extended test interval per this Code Case, as applicable.

test interval: the interval between test campaigns.

3 LIMITATIONS

3.1 Implementation of ISTD Requirements

ASME OM Code, Subsection ISTD shall be implemented prior to the use of this Code Case.

3.2 Defined Test Plan Groups (DTPGs)

This Code Case may be used for one or more DTPGs during a given test campaign. When combining DTPGs, the shorter test interval shall be applicable.

3.3 DTPGs Defined in ISTD-5253

This Code Case may not be used for DTPGs defined in para. ISTD-5253.

3.4 Code Case OMN-13

This Code Case shall not be used in conjunction with Code Case OMN-13.

3.5 Extension of Test Interval

The test interval may be extended by only one fuel cycle at a time.

3.6 Maximum Allowable Test Interval

The maximum allowable test interval shall be three fuel cycles plus the Code-allowed 60 days prior to the start of the scheduled refueling outage specified in para. ISTD-5240.

3.7 Snubber Failure Mode Groups (FMGs)

Snubber failure mode group (FMG) categories as defined in Subsection ISTD shall not be used to group snubber failures for DTPGs using this Code Case.

4 GENERAL REQUIREMENTS

4.1 Sample Size and Composition

For the test campaign immediately preceding an extended test interval and during the extended test interval, the initial sample size shall be as indicated in Table 1, Column A and selected randomly from the DTPG. When additional samples are required to satisfy the mathematical expression of Table 1, they shall be selected randomly from the remaining population of the DTPG.

4.2 Test Plans

Test plans listed in Table 1 are in lieu of test plans addressed in paras. ISTD-5260, ISTD-5300, and ISTD-5400.

4.3 Use of FMGs

Use of FMGs as described in paras. ISTD-5263 and ISTD-5270 is not applicable to this Code Case. All testing

Table 1 Test Plan Required for Test Campaign Immediately Preceding and During the Extended Interval

Test Plan [Note (1)]	DTPG Size, n	Column A Initial Sample Size [Note (2)]	Column B Mathematical Expression to Be Satisfied [Notes (2), (3)]
1	$n \geq 370$	52	$N \geq 51.60 + 21.03C$
2	$369 \geq n \geq 300$	$0.13n$	$N \geq 0.13n + C(0.1n)$
3	$299 \geq n \geq 250$	$0.14n$	$N \geq 0.14n + C(0.1n)$
4	$249 \geq n \geq 200$	$0.15n$	$N \geq 0.15n + C(0.1n)$
5	$199 \geq n \geq 150$	$0.18n$	$N \geq 0.18n + C(0.1n)$
6	$149 \geq n \geq 100$	$0.125n$	$N \geq 0.125n + C(0.125n)$
7	$n < 100$	13 [Note (4)]	$N \geq 12.5 + 12.5C$

GENERAL NOTES:

(a) Definitions of terms:

C = total number of unacceptable snubbers found in the DTPG
N = total number of snubbers tested that were selected from the DTPG
n = number of snubbers in the DTPG

(b) The requirements specified in Table 1 apply to the test campaign immediately preceding and during any extended test interval.

(c) The four preceding campaigns, required by para. 5.2, shall meet or exceed the requirements of Table 1 or of para. ISTD-5331 or ISTD-5431.

NOTES:

(1) Alternatively, Test Plan 1 may be used for DTPG sizes less than 370 snubbers.
(2) Fractional sample values shall be rounded up to the next integer.
(3) Additional testing may be required to satisfy the provisions of para. 5.1.
(4) For a DTPG smaller than 13, all snubbers in the DTPG must be successfully tested.

shall be in the respective DTPG until the mathematical expression of Table 1 is satisfied.

4.4 Action on Unacceptable Snubbers

Unacceptable snubbers shall be evaluated and adjusted, repaired, modified, or replaced. The provisions of paras. ISTD-1600 and ISTD-1700 also apply.

4.5 Retesting of Failed Snubbers

Snubbers placed in the same location as snubbers that failed the previous inservice operational readiness test shall be retested at the next refueling outage unless the cause of the failure is clearly established and that cause is corrected to preclude reoccurrences. Any retest or failures found by these retests do not require additional testing in accordance with this Code Case, but shall be evaluated for appropriate corrective action.

4.6 Service-Life Monitoring (SLM)

If testing is conducted specifically for service-life monitoring (SLM) purposes, the results of such testing does not require additional testing in accordance with this Code Case, but shall be evaluated for appropriate corrective action.

4.7 Snubbers Selected for SLM

Any snubbers selected for SLM or seal replacement during an applicable test campaign of this Code Case shall remain eligible for selection and testing under the test campaign.

4.8 Test Campaign Failure Rate

The test interval shall revert back to that specified in para. ISTD-5240 if the failure rate for the completed test campaign exceeds 2.5%.

4.9 Discontinuing Use of This Code Case

During any test campaign using this Code Case, if the entire DTPG population requires testing, usage of this Code Case shall be discontinued. The testing requirements of Subsection ISTD shall apply for that DTPG.

4.10 Functional Test Failures

All functional test failures identified during maintenance, SLM, transient dynamic events (para. ISTD-1750), and visual examination activities (para. ISTD-4230) conducted during the extended test interval shall be evaluated in accordance with paras. ISTD-1800 and ISTD-5270. If any condition indicates the snubber population level of operational readiness has degraded, corrective action shall be implemented as required by paras. ISTD-4270, ISTD-4280, ISTD-5271, and ISTD-5280.

5 SPECIFIC REQUIREMENTS

For the test campaign immediately preceding an extended test interval, the initial sample size shall be as indicated in Table 1, Column A (rounded up to the next integer) in lieu of the initial sample size listed in para. ISTD-5311 or ISTD-5411, as applicable. Testing shall satisfy the applicable mathematical expression listed in Table 1, Column B in lieu of equations listed in para. ISTD-5331 or ISTD-5431, as applicable.

5.1 Additional Specific Requirements for Implementing a Two Fuel Cycle Test Interval

Prior to implementing a two fuel cycle test interval, three successive single fuel cycle test campaigns shall be successfully completed for the applicable DTPG, with each test campaign failure rate not exceeding 2.5%. These test campaigns shall include the campaign conducted at the end of the fuel cycle immediately preceding the two cycle test interval.

5.2 Additional Specific Requirements for Implementing a Three Fuel Cycle Test Interval

Prior to implementing a three fuel cycle test interval, the following requirements shall be met:

(a) The test interval immediately preceding the three fuel cycle test interval shall be a two fuel cycle test interval.

(b) The four test campaigns immediately preceding the three fuel cycle test interval shall have been completed successfully.

Code Case OMN-15, Revision 2
Nonmandatory Appendix A
Example Scenarios

This Nonmandatory Appendix provides examples of various scenarios where the snubber inservice test (IST) interval specified in the ASME OM Code may or may not be extended.

NOTE: Test plan numbers referred to in this Nonmandatory Appendix are defined in Table 1 of OMN-15.

A-1 SCENARIO 1

DTPG 3 at Plant X has a total of 298 snubbers. A successful test campaign was completed during RFO 5 using the 10% Plan. A successful test campaign was completed during RFO 6 using the 37 Snubber Plan. What is required in order to bypass a test campaign at RFO 8?

Response: Completion of a successful test campaign at RFO 7 using either Test Plan 1 or Test Plan 3.

A-2 SCENARIO 2

Following Scenario 1 for DTPG 3 at Plant X, a test campaign was bypassed at RFO 8. What is required in order to bypass a test campaign at RFO 10 and RFO 11?

Response: Completion of a successful test campaign at RFO 9 using either Test Plan 1 or Test Plan 3.

A-3 SCENARIO 3

DTPG 3 at Plant X has a total of 298 snubbers. Successful test campaigns were completed during RFO 5 through 8. A successful test campaign was completed during RFO 9 using Test Plan 1. Is a test campaign required at RFO 10?

Response: No.

Is a test campaign required at RFO 11?

Response: Yes. The test interval may be extended by a maximum of one fuel cycle beyond the previous interval.

Code Case OMN-16
Use of a Pump Curve for Testing

Inquiry: What alternative requirements to those of Subsection ISTB may be used when it is impractical to adjust a centrifugal or vertical line shaft pump to a specific reference value as required by subpara. ISTB-5121(b), ISTB-5123(b), ISTB-5221(b), or ISTB-5223(b)?

Reply: It is the opinion of the Committee that the following alternative requirements may be used in lieu of subpara. ISTB-5121(b), ISTB-5123(b), ISTB-5221(b), or ISTB-5223(b) for testing of centrifugal or vertical line shaft pumps where adjustment to a specific reference value is impractical. Where a paragraph number is different than the existing Code, it shall be used to supplement the existing Code, and where the paragraph number is the same, it shall be used in lieu of the existing Code when testing using pump curves.

Applicability: 1998 Edition and subsequent editions and addenda through the OMb-2006 Addenda.

16-2100 ADDITIONAL DEFINITIONS

maximum pump curve range: the maximum potential flow or differential pressure range for the pump curve, from shutoff conditions to maximum required flow rate.

reference curve: a range of values of a test parameter versus flow or differential pressure, for a centrifugal or vertical line shaft pump, measured or determined when the pump is known to be operating acceptably.

16-3300 ESTABLISHING REFERENCE CURVES

Reference curves shall be obtained as follows:

(a) Initial reference curves shall be determined from the results of testing meeting the requirements of para. ISTB-3100, Preservice Testing, or from the results of testing performed in conjunction with the first inservice test.

(b) New or expanded reference curves shall be established as required by para. 16-3310, 16-3320, or subpara. 16-6200(c).

(c) Reference curves shall only be established when the pump is known to be operating acceptably.

(d) The range of the reference curve shall be sufficient to bound the points of operation expected during subsequent tests. The reference curve shall be established within ±20% of pump design flow rate for the comprehensive pump test.

(e) A reference curve shall be established from a minimum of three data points and have at least one data point for each 20% of the maximum pump curve range for the portion of the maximum pump curve established by the reference curve.

(1) A reference curve shall be established with the independent variable on the x-axis and the dependent variable on the y-axis. Alternately, the curve may be represented by an equation.

(2) If vibration is relatively unaffected by changing differential pressure or flow over the reference curve range, a single reference value may be used for that test quantity, provided it is at the minimum of the measured data.

(f) All subsequent test results shall be compared with the initial reference curves or new reference curves established in accordance with para. 16-3310, 16-3320, or subpara. 16-6200(c).

(g) Related conditions that can significantly influence the measurement or determination of the data points used to establish the reference curve shall be analyzed in accordance with para. ISTB-6400.

If reference curves are used, the reasons for doing so and suitability of the methods used to develop the reference curves and acceptance criteria shall be justified and documented in the record of tests (see section ISTB-9000).

16-3310 EFFECT OF PUMP REPLACEMENT, REPAIR, AND MAINTENANCE ON REFERENCE CURVES

When a reference curve(s) may have been affected by repair, replacement, or routine servicing of a pump, a new reference curve shall be determined in accordance with para. 16-3300 or the previous curve(s) reconfirmed by a comprehensive or Group A test run before declaring the pump operable. The Owner shall determine whether the requirements of para. ISTB-3100, to reestablish reference curves, apply. Deviations between the previous and new reference curves shall be identified, and verification that the new curves represent acceptable pump operation shall be placed in the record of tests (see section ISTB-9000).

16-3320 ESTABLISHMENT OF EXPANDED REFERENCE CURVES OR ADDITIONAL REFERENCE CURVES

If it is necessary or desirable, for some reason other than stated in para. 16-3310, to extend the current pump curve or establish an additional reference curve, an inservice test shall be run at the conditions of an existing set of reference values, or within the range of existing reference curves, and the results analyzed. If operation is acceptable, a second test run at the new reference conditions shall follow as soon as practicable. The results of this test shall establish the additional reference curves or be used to extend the range of the current reference curves. Whenever an additional set of reference curves, or extension of existing reference curves, is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTB-9000). The requirements of para. 16-3300 apply.

16-5120/16-5220 INSERVICE TEST PROCEDURE

An inservice test shall be conducted with the pump operating at the specified test conditions. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as directed in this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives and at a speed adjusted to the reference speed (±1%) for variable speed drives.

(b) Differential pressure, flow rate, and vibration (displacement or velocity, for Comprehensive or Group A tests) shall be determined and compared with the associated reference values from the reference curves. All deviations from the associated reference values shall be compared with the limits given in Table ISTB-5121-1 or ISTB-5221-1 and Fig. ISTB-5223-1 (Table ISTB-5100-1 or ISTB-5200-1 and Fig. ISTB-5200-1 in 2003 Addenda and earlier) and corrective action taken as specified in para. 16-6200. Comparison may be done graphically as shown in Examples 1 and 2 of Fig. 1.

(c) Vibration measurements shall be per the requirements of subpara. ISTB-5121(d), ISTB-5123(d), ISTB-5221(d), or ISTB-5223(d).

16-6200 CORRECTIVE ACTION

When using reference curves, determination of values falling in the alert or required action ranges may be done graphically, as shown in Examples 1 and 2 of Fig. 1.

(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, the frequency of testing specified in para. ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition corrected.

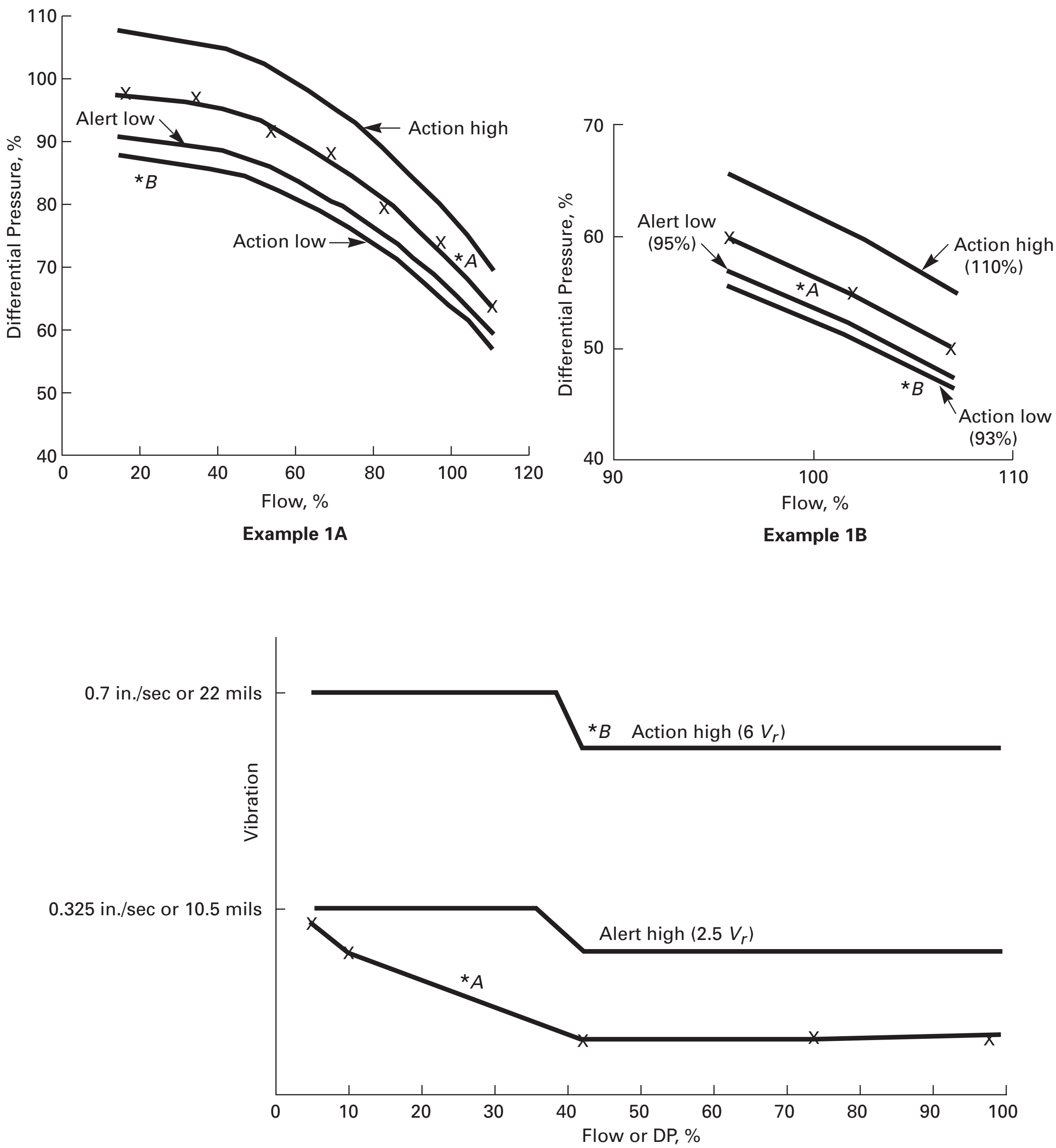
(b) Required Action Range. If the measured test parameter values fall within the required action range of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition corrected, or an analysis of the pump is performed and new reference values are established in accordance with subpara. ISTB-6200(c).

(c) New Reference Curves. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, and the pump's continued use at the changed values is supported by an analysis, a new set of reference curves may be established. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump and system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The results of this analysis shall be documented in the record of tests (see section ISTB-9000).

16-9500 DOCUMENTATION OF CODE CASE USAGE

Use of this Code Case shall be documented in the test plans per para. ISTA-3100.

Fig. 1 Examples of Graphical Evaluation of Tests Using Reference Curves **(15)**



A = acceptable operation
B = required action
X = data points used to establish reference curve

Code Case OMN-16, Revision 1
Use of a Pump Curve for Testing

Inquiry: What alternative requirements to those of Subsection ISTB may be used when it is impractical to adjust a centrifugal or vertical line shaft pump to a specific reference value as required by subpara. ISTB-5121(b), ISTB-5123(b), ISTB-5221(b), or ISTB-5223(b)?

Reply: It is the opinion of the Committee that the following alternative requirements may be used in lieu of subpara. ISTB-5121(b), ISTB-5123(b), ISTB-5221(b), or ISTB-5223(b) for testing of centrifugal or vertical line shaft pumps where adjustment to a specific reference value is impractical. Where a paragraph number is different than the existing Code, it shall be used to supplement the existing Code, and where the paragraph number is the same, it shall be used in lieu of the existing Code when testing using pump curves.

Applicability: 1998 Edition and subsequent editions and addenda through the OMa-2011 Addenda.

16-2100 ADDITIONAL DEFINITIONS

maximum pump curve range: the maximum potential flow or differential pressure range for the pump curve, from shutoff conditions to maximum required flow rate.

reference curve: a range of values of a test parameter versus flow or differential pressure, for a centrifugal or vertical line shaft pump, measured or determined when the pump is known to be operating acceptably.

16-3300 ESTABLISHING REFERENCE CURVES

Reference curves shall be obtained as follows:

(a) Initial reference curves shall be determined from the results of testing meeting the requirements of para. ISTB-3100, Preservice Testing, or from the results of testing performed in conjunction with the first inservice test.

(b) New or expanded reference curves shall be established as required by para. 16-3310, 16-3320, or subpara. 16-6200(c).

(c) Reference curves shall only be established when the pump is known to be operating acceptably.

(d) The range of the reference curve shall be sufficient to bound the points of operation expected during subsequent tests. The reference curve shall be established within ±20% of pump design flow rate for the comprehensive pump test.

(e) A reference curve shall be established from a minimum of three data points and have at least one data point for each 20% of the maximum pump curve range for the portion of the maximum pump curve established by the reference curve.

(1) A reference curve shall be established with the independent variable on the x-axis and the dependent variable on the y-axis. Alternately, the curve may be represented by an equation.

(2) If vibration is relatively unaffected by changing differential pressure or flow over the reference curve range, a single reference value may be used for that test quantity, provided it is at the minimum of the measured data.

(f) All subsequent test results shall be compared with the initial reference curves or new reference curves established in accordance with para. 16-3310, 16-3320, or subpara. 16-6200(c).

(g) Related conditions that can significantly influence the measurement or determination of the data points used to establish the reference curve shall be analyzed in accordance with para. ISTB-6400.

If reference curves are used, the reasons for doing so and suitability of the methods used to develop the reference curves and acceptance criteria shall be justified and documented in the record of tests (see section ISTB-9000).

16-3310 EFFECT OF PUMP REPLACEMENT, REPAIR, AND MAINTENANCE ON REFERENCE CURVES

When a reference curve(s) may have been affected by repair, replacement, or routine servicing of a pump, a new reference curve shall be determined in accordance with para. 16-3300 or the previous curve(s) reconfirmed by a comprehensive or Group A test run before declaring the pump operable. The Owner shall determine whether the requirements of para. ISTB-3100, to reestablish reference curves, apply. Deviations between the previous and new reference curves shall be identified, and verification that the new curves represent acceptable pump operation shall be placed in the record of tests (see section ISTB-9000).

16-3320 ESTABLISHMENT OF EXPANDED REFERENCE CURVES OR ADDITIONAL REFERENCE CURVES

If it is necessary or desirable, for some reason other than stated in para. 16-3310, to extend the current pump curve or establish an additional reference curve, an inservice test shall be run at the conditions of an existing set of reference values, or within the range of existing reference curves, and the results analyzed. If operation is acceptable, a second test run at the new reference conditions shall follow as soon as practicable. The results of this test shall establish the additional reference curves or be used to extend the range of the current reference curves. Whenever an additional set of reference curves, or extension of existing reference curves, is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTB-9000). The requirements of para. 16-3300 apply.

16-5120/16-5220 INSERVICE TEST PROCEDURE

An inservice test shall be conducted with the pump operating at the specified test conditions. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as directed in this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives and at a speed adjusted to the reference speed (±1%) for variable speed drives.

(b) Differential pressure, flow rate, and vibration (displacement or velocity, for Comprehensive or Group A tests) shall be determined and compared with the associated reference values from the reference curves. All deviations from the associated reference values shall be compared with the limits given in Table ISTB-5121-1 or ISTB-5221-1 and Fig. ISTB-5223-1 (Table ISTB-5100-1 or ISTB-5200-1 and Fig. ISTB-5200-1 in 2003 Addenda and earlier) and corrective action taken as specified in para. 16-6200. Comparison may be done graphically as shown in Examples 1 and 2 of Fig. 1.

(c) Vibration measurements shall be per the requirements of subpara. ISTB-5121(d), ISTB-5123(d), ISTB-5221(d), or ISTB-5223(d).

16-6200 CORRECTIVE ACTION

When using reference curves, determination of values falling in the alert or required action ranges may be done graphically, as shown in Examples 1 and 2 of Fig. 1.

(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, the frequency of testing specified in para. ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition corrected.

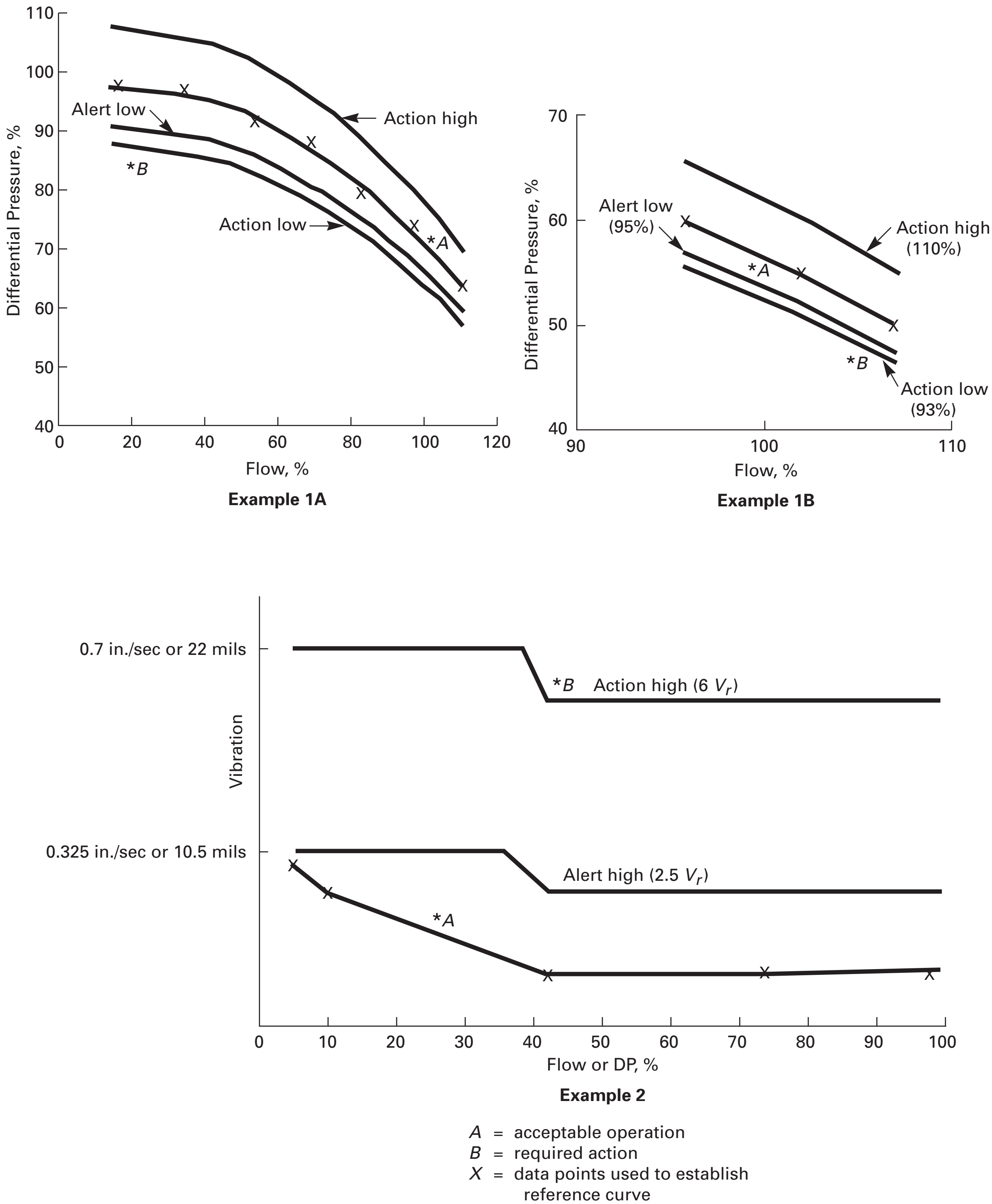
(b) Required Action Range. If the measured test parameter values fall within the required action range of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition corrected, or an analysis of the pump is performed and new reference values are established in accordance with subpara. ISTB-6200(c).

(c) New Reference Curves. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5121-1 or ISTB-5221-1 (Table ISTB-5100-1 or ISTB-5200-1 in 2003 Addenda and earlier), as applicable, and the pump's continued use at the changed values is supported by an analysis, a new set of reference curves may be established. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump and system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The results of this analysis shall be documented in the record of tests (see section ISTB-9000).

16-9500 DOCUMENTATION OF CODE CASE USAGE

Use of this Code Case shall be documented in the test plans per para. ISTA-3100.

(15) **Fig. 1 Examples of Graphical Evaluation of Tests Using Reference Curves**



Code Case OMN-17
Alternative Rules for Testing ASME Class 1 Pressure Relief/Safety Valves

Inquiry: What alternative may be used in lieu of the ASME OM Code 1995 Edition through the 1997 Addenda of Appendix II-1.3.3, the 1998 Edition through 2000 Addenda of Appendix II-1330, and the 2001 Edition through the 2006 Addenda of Appendix I, Section I-1320?

Reply: It is the opinion of the Committee that the following alternative may be used.

1 TEST FREQUENCIES, CLASS 1 PRESSURE RELIEF VALVES

(a) 72-Month Test Interval. Class 1 pressure relief valves and PWR Main Steam Safety Valves shall be tested at least once every 72 months (6 yr), starting with initial electric power generation. A minimum of 20% of the valves from each valve group shall be tested within any 24-month interval. This 20% shall consist of valves that have not been tested during the current 72-month interval, if they exist. The test interval for any individual valve that is in service shall not exceed 72 months except that a 6-month grace period is allowed to coincide with refueling outages to accommodate extended shutdown periods.

(b) Replacement With Pretested Valves. The Owner may satisfy testing requirements by installing pretested valves to replace valves that have been in service, provided that

(1) for replacement of a partial complement of valves, the valves removed from service shall be tested prior to resumption of electric power generation and shall be subjected to the maintenance specified in subpara. (d) or

(2) for replacement of a full complement of valves, the valves removed from service shall be tested within 24 months of removal from the system

(c) Requirements for Testing Additional Valves. Additional valves shall be tested in accordance with the following requirements:

(1) For each valve tested for which the as-found set-pressure (first test actuation) exceeds the greater of either the plus/minus tolerance limit of the Owner-established set-pressure acceptance criteria or ±3% of valve nameplate set-pressure, two additional valves shall be tested from the same valve group.

(2) If the as-found set-pressure of any of the additional valves tested in accordance with subpara. (c)(1) exceeds the criteria noted therein, then all remaining valves of that same valve group shall be tested.

(3) The Owner shall evaluate the cause and effect on system capability of valves that fail to comply with the set-pressure acceptance criteria established in subpara. (c)(1), or the acceptance criteria for other required tests (e.g., acceptance of auxiliary actuating devices, compliance with Owner's seat tightness criteria). Based upon this evaluation, to address any generic concerns, the Owner shall determine the need for testing in addition to the minimum tests specified.

(d) Maintenance. The Owner shall disassemble and inspect each valve after as-found set-pressure testing to verify that parts are free of defects resulting from time-related degradation or service-induced wear. Based upon this inspection, the owner shall determine the need for additional inspections or testing to address any generic concerns. As-left set-pressure testing shall be performed following maintenance and prior to returning the valve to service.

(e) Disassembly and Inspection. Each valve shall have been disassembled and inspected in accordance with subpara. (d) above prior to the start of the 72-month test interval. Disassembly and inspection performed prior to the implementation of this Code Case may be used.

Code Case OMN-18
Alternate Testing Requirements for Pumps Tested Quarterly Within ±20% of Design Flow

Background: When Subsection ISTB was revised in 1994 to include the Comprehensive Pump Test, the primary purpose of the Comprehensive Pump Test was to address centrifugal pumps normally tested on mini-flow recirculation. Testing at mini-flow did not provide good data to identify degradation, so the Comprehensive Test was added to ensure that those pumps would be tested further out on the curve, with the best instrumentation available, every 2 yr (once per outage). It was not the position of Subsection ISTB that there was a problem with the data obtained from pumps tested using full-flow test loops.

This change caused an issue for plants with full-flow test loops, as they were required once every 2 yr to install more accurate test pressure gauges, and use more restrictive test criteria. Additionally, it caused problems with trending, as the data from the tests with the more accurate instruments was not always directly comparable with the quarterly data.

This Code Case allows the Owner to not perform the Comprehensive Test with the associated acceptance criteria, if the quarterly test is performed at the flow rate and with the instrumentation required for the comprehensive test.

NOTE: Subsection ISTB allows the Owner to categorize the pumps in their program. As such, an Owner could categorize a pump that otherwise meets the requirements of Group B, as a Group A pump, and test according to this Code Case. However, in doing so they are obtaining additional data (vibration and flow or differential pressure) quarterly, rather than once every 2 yr.

Inquiry: What alternative rules to those of para. ISTB-3400 (para. ISTB 5.1 in the OMc-1994 Addenda through the OMb-1997 Addenda) may be used for Group A pumps that are tested quarterly within ±20% of pump design flow rate?

Reply: It is the opinion of the Committee that in lieu of the requirements of para. ISTB-3400 (para. ISTB 5.1 in the OMc-1994 Addenda through the OMb-1997 Addenda), the Group A test may be performed quarterly within ±20% of pump design flow rate, with instrumentation meeting the requirements of Table ISTB-3510-1 (Table ISTB-3500-1 in the 1998 Edition through the 2003 Addenda, Table ISTB 4.7.1-1 in the OMc-1994 Addenda through the OMb-1997 Addenda) for the Comprehensive and Preservice Tests, and no comprehensive test is required.

Applicability: OMc-1994 Addenda, and subsequent Editions and Addenda through the 2006 Addenda.

Code Case OMN-19
Alternative Upper Limit for the Comprehensive Pump Test

Background: Owners are having difficulties based on normal data scatter with implementation of the comprehensive pump test's current "Required Action Range" upper limit of 3% above the established reference value for the measured hydraulic value of differential pressure, discharge pressure, or flow. Owners have had to declare pumps inoperable for reasons other than a pump degradation issue. A "Required Action Range" upper limit of 6% above the reference value is a realistic value that should allow any true degradation issues to be captured and should alleviate unnecessarily declaring pumps inoperable.

This issue was also discussed at the ASME/NRC special meeting on June 4, 2007. The basis for the 1.06 upper limit is established in the white paper for the Code change that was approved under Standards Committee Ballot 09-610, record 09-657. This white paper discussed the impact of instrument inaccuracies, human factors involved with setting and measuring test parameters, readability of gauges, and other miscellaneous factors on the ability to meet the 1.03 criteria. Operating experience was also discussed in the white paper.

Inquiry: What alternative acceptance criteria may be used in place of the 1.03 reference value multiplier for the comprehensive pump test's upper "Acceptable Range" criteria and "Required Action Range, High" criteria referenced in the applicable ISTB test acceptance criteria tables?

Reply: It is the opinion of the Committee that a multiplier of 1.06 times the reference value may be used in lieu of the 1.03 multiplier for the comprehensive pump test's upper "Acceptable Range" criteria and "Required Action Range, High" criteria referenced in the ISTB test acceptance criteria tables listed in Table 1.

Applicability: ASME OMc Code-1994 Addenda through the ASME OM-2009 Edition.

Table 1 Test Acceptance Criteria Tables Affected by Alternative Upper Limit for the Comprehensive Pump Test

Applicable Code	Applicable ISTB Test Acceptance Criteria Table(s)
ASME OMc Code-1994 Addenda, ASME OM Code-1995 Edition, ASME OMa Code-1996 Addenda, ASME OMb Code-1997 Addenda	Table ISTB 5.2.3-1, Comprehensive Test Hydraulic Acceptance Criteria
ASME OM Code-1998, ASME OMa-1999 Addenda, ASME OMb Code-2000 Addenda, ASME OM Code-2001 Edition, ASME OMa Code-2002 Addenda, ASME OMb Code-2003 Addenda	Table ISTB-5100-1, Centrifugal Pump Test Acceptance Criteria Table ISTB-5200-1, Vertical Line Shaft and Centrifugal Pumps Test Acceptance Criteria Table ISTB-5300-1, Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria Table ISTB-5300-2, Reciprocating Positive Displacement Pump Test Acceptance Criteria
ASME OM Code-2004, ASME OMa Code-2005, ASME OMb Code-2006, ASME OM-2009	Table ISTB-5121-1, Centrifugal Pump Test Acceptance Criteria Table ISTB-5221-1, Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria Table ISTB-5321-1, Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria Table ISTB-5321-2, Reciprocating Positive Displacement Pump Test Acceptance Criteria

Code Case OMN-20
Inservice Test Frequency

Inquiry: What alternative(s) may be applied to the test frequencies for pumps and valves specified in ASME OM, Division 1, Section IST, 2009 Edition through OMa-2011 Addenda and all earlier editions and addenda?

Reply: It is the opinion of the Committee that for the test frequencies for pumps and valves specified in ASME OM, Division 1, Section IST, 2009 Edition through OMa-2011 Addenda and all earlier editions and addenda, the below requirements may be applied.

1 TEST FREQUENCY GRACE

ASME OM, Division 1, Section IST and all earlier editions and addenda specify component test frequencies based either on elapsed time periods (e.g., quarterly, 2 yr, etc.) or the occurrence of plant conditions or events (e.g., cold shutdown, refueling outage, upon detection of a sample failure, following maintenance, etc.).

(a) Components whose test frequencies are based on elapsed time periods shall be tested at the frequencies specified in Section IST with a specified time period between tests as shown in Table 1. The specified time period between tests may be reduced or extended as follows:

(1) For periods specified as fewer than 2 yr, the period may be extended by up to 25% for any given test.

(2) For periods specified as greater than or equal to 2 yr, the period may be extended by up to 6 months for any given test.

(3) All periods specified may be reduced at the discretion of the owner (i.e., there is no minimum period requirement).

Period extension is to facilitate test scheduling and considers plant operating conditions that may not be suitable for performance of the required testing (e.g., performance of the test would cause an unacceptable increase in the plant risk profile due to transient conditions or other ongoing surveillance, test, or maintenance activities). Period extensions are not intended to be used repeatedly merely as an operational convenience to extend test intervals beyond those specified.

Period extensions may also be applied to accelerated test frequencies (e.g., pumps in alert range) and other fewer than 2-yr test frequencies not specified in Table 1.

Period extensions may not be applied to the test frequency requirements specified in Subsection ISTD, Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants, as Subsection ISTD contains its own rules for period extensions.

(b) Components whose test frequencies are based on the occurrence of plant conditions or events may not have their period between tests extended except as allowed by ASME OM, Division 1, Section IST, 2009 Edition through OMa-2011 Addenda and all earlier editions and addenda.

Table 1 Specified Test Frequencies

Frequency	Specified Time Period Between Tests
Quarterly (or every 3 months)	92 days
Semiannually (or every 6 months)	184 days
Annually (or every year)	366 days
x years	x calendar years where x is a whole number of years ≥ 2

Code Case OMN-21
Alternative Requirements for Adjusting Hydraulic Parameters to Specified Reference Points

Inquiry: What alternatives to the requirements of paras. ISTB 5.2.1, ISTB 5.2.2, and ISTB 5.2.3 in the 1995 Edition, 1996 Addenda, and paras. ISTB-5121, ISTB-5122, ISTB-5123, ISTB-5221, ISTB-5222, ISTB-5223, ISTB-5321, ISTB-5322, and ISTB-5323 in the 1998 Edition through the 2009 Edition, 2011 Addenda may be used when it is impractical to operate a pump at a specified reference point and adjust the resistance of the system to a specified reference point for flow rate, differential pressure, or discharge pressure?

Reply: It is the opinion of the Committee that when it is impractical to operate a pump at a specified reference point and adjust the resistance of the system to a specified reference point for flow rate, differential pressure, or discharge pressure, the pump may be operated as close as practical to the specified reference point with the following requirements: The Owner shall adjust the system resistance to as close as practical to the specified reference point where the variance from the reference point does not exceed +2% or −1% of the reference point when the reference point is flow rate, or +1% or −2% of the reference point when the reference point is differential pressure or discharge pressure.

Applicability: ASME OM Code-1995 Edition through 2011 Addenda.

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