Report of the U.S. Nuclear Regulatory Commission Piping Review Committee

Evaluation of Seismic Designs - A Review of Seismic Design
Requirements for Nuclear Power Plant Piping

U.S. Nuclear Regulatory
Commission

Prepared by the Seismic Design Task Group

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Manuscript Completed: February 1985
Date Published: April 1985

Prepared by
The Seismic Design Task Group

U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

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FOREWORD

The Executive Director for Operations of the U. S. Nuclear Regulatory Commission (NRC) requested that a comprehensive review be made of NRC requirements in the area of nuclear power plant piping. In response to this request, an NRC Piping Review Committee was formed. The activities of this Committee were divided into four tasks handled by appropriate Task Groups. These were:

- Pipe Crack Task Group
- Seismic Design Task Group
- Pipe Break Task Group
- Dynamic Loads and Load Combination Task Group

Each Task Group has prepared a report appropriate to its scope. In addition, the Piping Review Committee will prepare an overview document rationalizing areas of overlap between the Task Groups. This will be released as a separate report.

The project titles of the five volumes are:

Volume 1 - Investigation and Evaluation of Stress-Corrosion Cracking in Piping of Boiling Water Reactor Plants

Volume 2 - Evaluation of Seismic Designs - A Review of Seismic Design Requirements for Nuclear Power Plant Piping

Volume 3 - Evaluation of Potential for Pipe Breaks

Volume 4 - Evaluation of Other Dynamic Loads and Load Combinations

Volume 5 - Summary - Piping Review Committee Conclusions and Recommendations

SEISMIC DESIGN TASK GROUP MEMBERS

Shou-Nien Hou, Chairman
Goutam Bagchi
Daniel J. Guzy
Kamal A. Manoly
John A. O'Brien

The conclusions and recommendations presented in the Executive Summary and other identified sections of this report are those of the Seismic Design Task Group itself and do not necessarily reflect the technical positions of the individual consultants.

Seismic Design Task Group Consultants

C.K. Chou of Lawrence Livermore National Laboratory contributed information and suggestions on damping values, spectra modification, and overall design margins. He also provided overall logistic and technical assistance to the Task Group.

R.P. Kennedy of Structural Mechanics Associates contributed information and suggestions on inelastic piping response and on issues concerning the operating basis earthquake vs. the safe shutdown earthquake.

M. Reich of Brookhaven National Laboratory contributed information and suggestions on piping support design as well as on single-envelope spectrum vs. multiple-response spectra methods.

E.C. Rodabaugh of E.C. Rodabaugh Associates contributed information and suggestions on nozzle load design limits, strain rate effects, and overall design margins.

J.D. Stevenson of Stevenson & Associates contributed information and suggestions on the use of snubbers, foreign seismic design criteria, and piping performance in actual earthquake events.

These consultants are the primary authors of the technical information given in Chapters 2, 3, and 4 and in the appendices to this report. This information formed much of the basis for the Task Group's recommendations. However, it should be noted that some of the consultants' suggestions were not adopted by the Task Group. No immediate Task Group action will be taken on those consultants' suggestions that were not adopted, but they are presented in this report for general information only.

EXECUTIVE SUMMARY

The Code of Federal Regulations Title 10 Part 50 requires that structures, systems, and components important to the safety of nuclear power plants be designed to withstand individual and combined effects caused by normal operations, by extreme natural phenomena, and by postulated accident conditions. The U.S. Nuclear Regulatory Commission staff, through various standards such as regulatory guides, branch technical positions, and the standard review plan, has specified how these effects are to be considered in the design of safety-related structures, systems, and components. In the area of nuclear power plant piping, several of the current regulatory criteria and industry design practices had to be developed without extensive supporting data. Information obtained since their development has indicated that current nuclear piping design could be improved to increase overall safety and to reduce unnecessary costs.

This report presents the findings and recommendations of the Seismic Design Task Group of the NRC Piping Review Committee and includes contributions from consultants. The Task Group was directed to review current seismic criteria pertaining to piping such as definition of seismic loads, construction of floor response spectra, calculation of piping seismic response, and state-of-the-art design practice. The Task Group was further directed to evaluate and recommend changes in current requirements for piping design, drawing on both domestic and foreign experience in the process.

Current nuclear piping systems use significantly more snubbers and other seismic supports than systems in older plant designs. These stiffer designs are the result of conservatism added in both design criteria and design practice to account for the large uncertainty inherent in predicting seismic effects. Today, however, in light of new data and a more integrated view of piping system behavior, it seems that some of these conservatisms are excessive. Because stiff systems generate high stresses and nozzle loads resulting from restraint of thermal expansion and can be more adversely influenced by construction, maintenance, and inspection errors, many experts believe that they diminish overall plant safety.

This report identifies the major issues influencing seismic design and discusses the effects of current regulatory criteria and design practices. Recommendations are then presented for resolving these individual issues. In developing these recommendations, the Task Group recognized that a fundamental resolution of all technical issues will require advancement in many technical areas. An optimum balance among all factors affecting piping design may not be achievable in the near future. Initial efforts by the Task Group therefore concentrated on identifying key elements affecting design and understanding the effects of each. From this understanding, a practical near-term regulatory position can be established to modify design. This would yield an immediate improvement in reliability during normal operation even though a more integrated approach to piping design may still be several years away.

Truly optimum design criteria will ultimately not only resolve technical issues but will also improve safety. Although any detailed value-impact analysis is outside the charter of the Piping Review Committee, the Task Group has given qualitative consideration to cost-benefit in developing its specific recommendations. For example, in those situations where it is clear that substantial

benefit could be realized at minimal implementation cost, the Task Group suggests items for immediate NRC action, including changes in current design criteria. In situations where potential technical benefit exists but the implementation cost of regulation change is uncertain, suggestions for further action, including relevant research programs, have been made.

The specific technical issues studied by the Task Group are presented below, together with recommendations for (1) immediate NRC action, (2) changes in regulatory positions, and (3) research programs to improve understanding of specific technical issues.

Damping Values

Because of a lack of understanding of the parameters affecting damping, lower-bound values are currently used for seismic design (Regulatory Guide 1.61). The use of higher allowable damping values would reduce calculated response and thus allow increased piping system flexibility. Experimental evidence to date suggests a strong correlation between damping and frequency. In light of this evidence, the Pressure Vessel Research Committee (PVRC) has recommended a technical position allowing 5% of critical damping for piping frequencies up to 10 Hz, 2% for frequencies between 20 Hz and 33 Hz, with linearly varying damping between 10 Hz and 20 Hz. This has been adopted by the ASME as Code Case N-411.

The Task Group makes the following recommendations regarding damping values for piping design:

- o Action Items
 - Immediately endorse ASME Code Case N-411 for use in calculating seismic response using spectral analysis methods. (This limited endorsement does not apply to damping values for time-history analysis.)
- o Change in Regulatory Position
 - Revise Regulatory Guide 1.61 and Standard Review Plan 3.9.2 to incorporate the new damping criteria.
- o Research Programs
 - Complete the Idaho National Engineering Laboratory (INEL) damping tests, which should establish more precisely the dependency of damping to both modal response frequency and load frequency.
 - Investigate the possibility of applying the PVRC damping position to dynamic loads other than seismic, and address proper damping for frequencies above 33 Hz.

Spectra Modifications

Regulatory Guide 1.122 stipulates that the peaks of floor response spectra used for piping design be broadened by $\pm 15\%$ to account for uncertain structural frequencies resulting from uncertainties in parameters such as material properties of the structure and soil damping values, soil-structure-interaction analysis techniques, and approximations in modeling techniques used in seismic analysis. In reality, a piping system will excite at only one peak frequency in the artificially broadened range. The required $\pm 15\%$ peak broadening takes into account the uncertainties associated with frequency estimation, but also substantially (and artificially) increases the total energy input to the piping system. As a result, this requirement introduces additional conservatism into the seismic piping design. The PVRC has recommended an alternative to peak broadening whereby response spectra peaks would be shifted throughout the $\pm 15\%$ range and the responses to various inputs, rather than the inputs themselves, would be enveloped. This has been adopted by the ASME as Code Case N-397 and will also be included in Appendix N of the 1984 Summer Addendum to the ASME Code.

The Task Group makes the following recommendations regarding spectra modification:

- o Action Items
 - Immediately endorse ASME Code Case N-397.
 - Initiate NRC internal review regarding the adequacy of the $\pm 15\%$ range for treating uncertainties in spectral peak frequencies.
- o Change in Regulatory Position
 - Revise Regulatory Guide 1.122 to permit peak shifting as an alternative to peak broadening.
- o Research Programs
 - Assess uncertainty range of spectral frequencies, including uncertainties in piping system modeling.
 - Develop a simple spectra-broadening procedure based on equivalent energy input.

Nozzle Loads

Piping systems generally terminate at nozzles connected to piping, vessels, or rotating machinery. The design of piping branch connections and tank and vessel nozzles do not generally take credit for nozzle flexibility, resulting in higher calculated stresses. Also, equipment manufacturers often specify unnecessarily low nozzle allowable loads. Improving nozzle design procedures could help reduce the number of seismic restraints required in current piping design and could lessen the restrictions of present nozzle load limits when new piping criteria (e.g., damping) are introduced.

The Task Group makes the following recommendations with regard to nozzle loads:

o Action Items

- Request that the ASME Section III Working Group on Piping Design revise ASME Code sections addressing pipe system flexibility calculation to also consider tank and vessel nozzle flexibility. (Completed)

o Change in Regulatory Position

- Revise Standard Review Plan 3.9.2 to consider nozzle flexibility in piping analysis.

o Research Programs

- Develop improved design guidance on nozzle stress limits and flexibilities.

Inelastic Response

Well-designed piping systems are capable of absorbing and dissipating a considerable amount of energy when strained beyond their elastic limit. Also, an earthquake is capable of inputting only a limited amount of energy into such systems. Unless adjusted, a linear-elastic response analysis cannot account for the inelastic energy absorption capacity present at even the Service Level C or D stress levels and therefore gives credit for only a fraction of the total energy absorption capability of the piping system. This conservatism leads to the use of more pipe restraints than are actually necessary to ensure acceptable margins against failure for dynamic loads that may occur. As a result, piping system stiffness is increased causing a potential decrease in overall reliability.

The Task Group makes the following recommendations regarding consideration of inelastic piping system response:

o Change in Regulatory Position

- Revise Standard Review Plan 3.9.2 to state the goal of safe-shutdown-earthquake performance criteria to be used in nonlinear piping analysis. Such performance criteria would establish a minimum margin against failure, where failure would be defined as (1) the onset of plastic tensile instability, (2) low-cycle fatigue or plastic ratcheting, (3) the onset of local or system buckling, (4) excessive deformation (resulting in more than a 15% reduction in cross-sectional flow area), or (5) functional failure of pipe-mounted equipment.

o Research Programs

- Develop pseudolinear-elastic estimation methods, and design procedures to account for inelastic response.

Uniform-Envelope vs. Multiple-Response Spectra Methods

Because pipe supports are often attached to structural members located at different elevations in one or more buildings, piping systems will experience multiple acceleration inputs during an earthquake. The total response of the pipe will depend on its own inertia as well as on the differential motion between support attachments. Time-history finite-element analyses are capable of capturing this response but are very costly. Therefore, most nuclear piping systems are qualified by response spectra methods using envelope spectra input from Regulatory Guide 1.60 for the dynamic responses and a separate seismic analysis for the pipe response due to support motion; the results of these two analyses are then combined by absolute sum.

Brookhaven National Laboratory has recently completed (reported in NUREG/CR-3811) an NRC-funded evaluation of multiple-response spectra methods for evaluating piping systems. Multiple-response spectra methods, being closer to reality than the uniform-envelope excitation assumption, could result in less design conservatism while still providing the required margin of safety. Furthermore, computer run times are comparable to those required for present response spectra methods.

The Task Group makes the following recommendations regarding multiple independent spectra input:

o Change in Regulatory Positions

- Revise Standard Review Plan 3.9.2 to permit and encourage the use of multiple-response spectra methods for more realistic seismic response analysis (for details, see Section 2 of Volume 4 of NUREG-1061).

o Research Programs

- Investigate phase correlation between floor responses, and recommend changes to spectra combination methods, as appropriate.

Overall Design Margins

A key element in the development of optimized design criteria is that a proper balance be maintained among the margins associated with various individual effects such as seismic and thermal loads. In balancing a design for these various effects, it is important to achieve this balance at the level of actual failure, rather than that of a code-defined standard.

The most appropriate balance among effects is difficult to define because of a lack of real failure information for piping, particularly for seismic loads. The current ASME Code stress criteria were developed considering piping collapse as the chief failure mode for seismic inertial loads. However, many experts now feel that low-cycle fatigue, or fatigue/ratchetting, is the likely failure mode. Our limited data base of piping failure (see the Addendum to Volume 2 of NUREG-1061) seems to strengthen this belief. If this can be adequately proven, appropriate changes to the ASME Code could likely result in more flexible piping system design. Development of a final position will require a research program to review behavior of piping in real strong-motion earthquakes and review of all

existing or planned test programs on seismic design to determine if their results are suitable for incorporating margins against failure into design regulations.

The Task Group makes the following suggestions for rationalizing overall design margins:

o Action Items

- Monitor and assess PVRC piping activities and ASME Code revisions as appropriate.
- Assess piping experience when a seismic event occurs.

o Research Programs

- Test programs (e.g., EPRI's piping capacity tests) for verifying piping seismic design margins and identifying failure modes should be supported. Evaluate test results and provide recommendations for criteria changes (e.g., reclassification of seismic inertial stresses as "secondary"), as appropriate.
- Encourage the nuclear industry to establish and justify an earthquake level that piping systems can sustain with sufficient confidence that no seismic analysis is needed.

Operating Basis Earthquake vs. Safe Shutdown Earthquake

Originally, the seismic design of nuclear power plants followed the same basic concept applied to other industrial facilities located in areas of high seismicity. Plant design was governed by the effects of an earthquake determined to have a reasonable probability of occurrence during the plant design life and then was "safety checked" against a larger earthquake generally assumed to induce ground motion twice that of the design earthquake. However, design emphasis eventually shifted so that an independently established safe shutdown earthquake (SSE) was that emphasized in plant design. The lesser earthquake, referred to as the operating basis earthquake (OBE), is now generally specified as producing ground motion one-half that of the SSE. As a result, the original concept of the OBE as having a "reasonable" probability of occurrence during plant life may have been lost.

Although current design practice normally sets a plant's OBE at one-half the SSE ground motion, some plants have lower OBE to SSE ratios. The Atomic Safety and Licensing Appeal Board's June 16, 1981 decision on Diablo Canyon clarifies that the OBE does not have to be directly coupled to the SSE value. The practice of setting OBE input to one-half the SSE input has several major impacts on the seismic design of piping systems:

1. The design requirement to safely shut down the plant up to the SSE level seems sufficient to ensure nuclear safety. It should be left to the discretion of the plant owner to define a "reasonable" level for which the plant must be designed to remain functional.

2. Current design criteria define different structure and pipe damping values for the OBE than for the SSE, requiring that two separate seismic analyses be performed. This increases analytical effort without clearly adding to safety or reliability.
3. In the absence of loss-of-coolant-accident (LOCA) or pipe-break loads, the OBE at Service Level B controls piping design over the SSE at Service Level D.

The Task Group makes the following recommendations regarding design for the OBE and the SSE:

o Action Items

- Initiate an NRC internal review to investigate the feasibility of using uniform structural and piping damping values for evaluating both the OBE and SSE and thus permit scaling of a single earthquake analysis.
- Request ASME to consider effects of seismic anchor movement at Service Level D (rather than at Level B) when the OBE becomes decoupled from the SSE.

o Change in Regulatory Positions

- Recommend that rulemaking be undertaken that would change the OBE definition in Appendix A to 10 CFR Part 100 to permit decoupling of the OBE and SSE.

Use of Snubbers

Snubbers are devices installed in piping systems to limit relatively rapid dynamic motion while permitting relatively slow motion. Operating experience has indicated that neither mechanical nor hydraulic snubbers have always performed reliably in service. In order to improve the overall reliability of otherwise passive piping systems, the use of snubbers to meet piping system design requirements should be limited.

The Task Group suggests a program to limit the use of snubbers on safety-related piping in nuclear power plants, including the following specific recommendations:

o Action Items

- Initiate a nonmandatory snubber reassessment program for operating plants and plants under construction.

o Research Programs

- Encourage the nuclear industry to investigate methods and procedures to limit the use of snubbers.
- Complete the Pacific Northwest Laboratories' study of Licensee Event Reports related to snubber performance to identify failure causes and

effectiveness of various snubber types, and suggest methods of improving performance such as periodic testing or qualification testing.

Support Design

Current design practice addresses independently seismic margins for component supports, pipe supports, and piping. A more integrated approach to piping system design that considers the interaction between support and piping response and failure could improve overall performance. It may be more desirable to establish separate seismic criteria for piping supports than for component supports.

The Task Group suggests that such an integrated approach to pipe-support system design be pursued and makes the following specific recommendations:

o Action Items

- Encourage PVRC and ASME activities to review and improve piping support design criteria.

o Research Programs

- Encourage the nuclear industry to develop procedures to optimize support placement and minimize the number of supports.
- Encourage the nuclear industry to investigate the effects of support gap size and installation tolerances on piping system behavior for both seismic and thermal loadings.
- Encourage the nuclear industry to assess performance of various piping supports.

General

Piping criteria changes leading to more flexible design (e.g., higher damping values) will also result in relatively greater earthquake displacements than would be experienced by current piping designs. These greater displacements increase the possibility of interaction with surrounding structures and equipment and also increase the motion of line-mounted equipment. These increased displacement effects should be considered in designing, or redesigning, piping systems. This should be addressed in Section 3.9.2 of the standard review plan.

The functionality criterion for piping will be maintained. Current ASME Code Class 1 or Class 2 stress evaluation procedures, not to exceed Level C limits, will be used. These limits are similar to those now being used on a case-by-case basis to satisfy the functionality criterion. It is recommended that the upcoming EPRI/NRC pipe tests be evaluated to confirm this position and to determine whether it is appropriate to use the current higher Level D stress limits.

Recognizing the important role that cost plays in the development of reasonable design criteria, the Task Group strongly recommends that any development effort include detailed value-impact evaluations. Attempts should be made to quantify both the individual and combined effects of the recommended and proposed piping criteria changes.

LIST OF ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
AE	Architect/Engineer
AECL	Atomic Energy of Canada, Ltd.
AEOD	Analysis and Evaluation of Operational Data
AIF	Atomic Industrial Forum
AIJ	Architect Institute of Japan
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
API	American Petroleum Institute
ASEA	Allmanna Svenska Elektriska Aktiebolaget (Sweden)
ASME	American Society of Mechanical Engineers
BNL	Brookhaven National Laboratory
BSA	Belgian Safety Authority
BWR	Boiling water reactor
CE	Corps of Engineers, U.S. Army
CRGR	Committee to Review Generic Requirements
DBPB	Design basis pipe break
DEGB	Double-ended guillotine break
EDF	Electricity Authority of France
EDO	Executive Director for Operations
EPRI	Electrical Power Research Institute
FSAR	Final Safety Analysis Report
GDC	General design criterion
HDR	Heissdampfreaktor (Federal Republic of Germany)
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
IGSCC	Intergranular stress corrosion cracking
KTA	Kern Technische Ausschuss (Germany)
LLNL	Lawrence Livermore National Laboratory
LOCA	Loss-of-coolant accident
MARK II & III	General Electric boiling water reactor containment types
MITI	Ministry of International Trade and Industry (Japan)
MS/FWPB	Main steam and feedwater pipe break
MWe	Megawatts (electrical)
NDE	Nondestructive examination
NEMA	National Electrical Manufacturers Association
NSSS	Nuclear steam supply system
OBE	Operating basis earthquake
OELD	Office of Executive Legal Director
PNL	Pacific Northwest Laboratory
PVRC	Pressure Vessel Research Committee, especially their Steering Committee on Piping Systems
PWR	Pressurized water reactor
RCL	Reactor coolant loop
RHRS	Residual heat removal system
SAM	Seismic anchor movement
SDE	Site design earthquake
SER	Safety Evaluation Report
SI	Seismic-induced
SOT	System operating transients

LIST OF ACRONYMS AND INITIALISMS (Continued)

SRP	Standard Review Plan
SRV	Safety relief valve
SRSS	Square root of the sum of the square
SSE	Safe shutdown earthquake
SSMRP	Seismic Safety Margins Research Program
TUV	Technical Supervisory Association (Federal Republic of Germany) Technischer Überwachungs Verein
USI	Unresolved safety issue
WRC	Welding Research Council

1. INTRODUCTION

As part of an ongoing effort to improve the reliability of piping in nuclear power plants, the Executive Director for Operations requested the formation of the NRC Piping Review Committee to (1) conduct a comprehensive review of NRC criteria for piping important to safety in new and operating plants, (2) recommend changes in current requirements, as appropriate, and (3) identify areas requiring further research or other action. The Committee, comprised of 17 NRC staff members assisted by expert consultants, is divided by technical issue into four task groups: pipe cracking, seismic design of piping, pipe break, and other dynamic loads and load combinations.

This report presents the findings and recommendations of the Seismic Design Task Group of the NRC Piping Review Committee. The Task Group was directed to review current seismic criteria pertaining to piping such as definition of seismic loads, construction of floor response spectra, calculation of piping seismic response, and state-of-the-art design practice. The Task Group was further directed to evaluate and recommend changes in current requirements for piping design, drawing on both domestic and foreign experience in the process. Chapters 2, 3, and 4 and the appendices to this report include suggestions from consultants, not all of which have been directly adopted by the Task Group and the Piping Review Committee. No immediate Task Group action will be taken on those consultants' suggestions that were not adopted, but they are presented in this report for general information only.

Current nuclear piping systems use significantly more snubbers and other seismic supports than do systems in older plant designs. These stiffer designs are the result of conservatisms added in both design criteria and design practice to account for the large uncertainty inherent in predicting seismic effects. Today, however, in light of new data and a more integrated view of piping system behavior, it seems that some of these conservatisms are excessive. Because stiff systems generate high stresses and nozzle loads resulting from restraint of thermal expansion and can be more adversely influenced by construction, maintenance, and inspection errors, many experts believe that they diminish overall plant safety.

Research evidence and operating experience have improved our understanding of such areas in piping seismic design as damping, multiply supported piping, response spectrum peak broadening, the use of snubbers to limit dynamic pipe loads, and industry design practice. The common awareness of these concerns led to formation of a Pressure Vessel Research Committee (PVRC) Steering Committee on Piping Systems in 1982, which represents a joint effort between NRC and the nuclear industry to reassess current piping design criteria. The Task Group has drawn on several PVRC proposals in recommending modifications to current regulatory requirements and identifying areas for future research.

This report is divided into five chapters. Chapter 2 discusses the issues associated with overlapping conservatism in seismic design. Chapter 3 addresses the roles of the OBE and SSE as design criteria. Chapter 4 defines problems

in current industry practices. Chapter 5 discusses briefly how seismic design issues interface with the areas considered by the other Piping Review Committee task groups.

Extensive technical appendices are included in support of the text, and references are included for those readers interested in further study of seismic design issues. In addition, a summary and evaluation of seismic damage to industrial piping is presented separately as an addendum to this report.

2. ISSUES REGARDING OVERLAPPING CONSERVATISM IN SEISMIC DESIGN

2.1 Problem Description

The Code of Federal Regulations Title 10 Part 50 [Ref. 2-1] requires that structures, systems, and components important to the safety of nuclear power plants be designed to withstand individual and combined effects caused by normal operation, by extreme natural phenomena, and by postulated accident conditions. The U.S. Nuclear Regulatory Commission, through its various standards such as regulatory guides, branch technical positions, and the standard review plan, has specified how these effects are to be considered in the design of safety-related structures, systems, and components.

The postulated accident loads and loads caused by natural phenomena such as earthquakes are random events having amplitude, duration, frequency of content, time of occurrence, and time-phase relationship that are random and stochastic. Each parameter has large uncertainties that make it difficult to define design loads for these events. Our general understanding is that such an event may not occur frequently, but whenever it does, it may introduce very large loads that may in turn have severe consequences. Therefore, when considering these dynamic events, the design philosophy has been based on judgment tending toward the conservative.

In addition to conservatisms built into the design chain by code specification and regulatory requirements, designers introduce still more conservatisms for economic reasons or because of inadequate guidance for refining design techniques. Examples include linear-elastic analysis vs. nonlinear actual behavior, response spectrum analysis vs. more realistic time-history analysis, and enveloped input vs. multiple-support actual excitation. In the real world situation, a simplified seismic design procedure is definitely necessary to deal with the approximately 100,000 feet of piping in each nuclear unit that must be analyzed for seismic loads.

Recently designed nuclear piping systems use significantly more seismic supports than older designs. These stiffer designs could produce higher thermal stresses under normal operating conditions, which would decrease reliability during daily operation. In addition, ductility characteristics are not fully used by a stiff structure that relies heavily on strength to achieve seismic resistance. Because of its energy-absorbing capability, a flexible structure subjected to dynamic loads may have a greater safety margin against failure than does a stiff structure. Also, a higher safety margin for a particular component in resisting one specific load, such as an earthquake, does not necessarily lead to higher overall reliability for the entire system or plant. This is because a stiff pipe will impart higher moments to the structure or component to which it is connected than a flexible pipe. Optimal piping system reliability may be ideally achieved by a design approach that considers all realistic loads, failure modes, and failure criteria. In developing piping design procedures based on reliability, three elements must be considered: (1) event occurrence rate, (2) pipe response as predicted by a best-estimate calculation, and (3) realistic failure mechanisms and failure criteria.

To develop optimal piping design procedures, one should carefully consider the relative contribution of thermal and seismic loads that a pipe might experience over the lifetime of the plant. Realistic rates of occurrence for thermal and seismic events should be weighed, along with the uncertainty in predicting these rates. On the one hand, we have over 100 years of experience with thermal design and can predict reasonably well thermal loads due to daily operation. On the other hand, the large uncertainty associated with seismic events prevents us from predicting seismic effects on piping with the same degree of accuracy. It is also important to consider the level of actual failure, and not just the level of any artificial standard (such as a design allowable stress) that may itself have imbalanced considerations embedded in it.

2.2 Damping Values

Damping is a hypothetical factor used to represent the energy dissipation in a structure. In analyzing a structure under near-resonance conditions, even small amounts of damping may have a significant effect on the amplitude and phase of the response. The influence of damping on dynamic response can only be established by experiments.

Current damping requirements for piping system seismic design are given in Regulatory Guide 1.61. It is widely felt that higher allowable damping values would be more realistic and would be beneficial to the nuclear industry by reducing the number of required piping supports and increasing the overall reliability of piping systems. Many countries have conducted various experiments to identify the parameters that can influence damping values, to correlate field-observed energy dissipation with analytical predictions, and to establish a technical basis for deriving more realistic damping values to be used in design. For example, the Japanese industry is currently conducting a large research program to define more realistic damping. From field observations as well as laboratory testing, higher damping values have been observed. Japanese industry has recommended to their regulatory authorities that the critical damping factor be increased from the current 0.5% to 3% for their larger design basis earthquake.

2.2.1 PVRC Effort on Damping

A Task Group on Damping Values was set up in the Technical Committee on Piping Systems of the Pressure Vessel Research Committee (PVRC). This technical committee consists of members from NRC, the nuclear industry, and the ASME Code committees. An objective of this PVRC committee is to determine and recommend more realistic damping values that can be used in performing seismic analysis of nuclear power plant piping systems. The approach this PVRC committee took was to (1) collect data, (2) compile the data in a matrix format according to a predetermined set of variables that possibly affect damping, (3) perform regression analyses to identify important variables, and (4) recommend damping values for implementation in design standards.

The PVRC collected data from a wide spectrum of both foreign and domestic sources, including laboratory and in-plant tests of piping with different sizes, types of supports, and types of excitation. Data evaluation combined three basic elements: individual judgmental evaluation, engineering assessment, and regression analysis. Individual judgment was used to identify key parameters that may affect damping values and thus the true representation of the energy dissipation capacity of piping systems. Engineering assessment was used to develop the correlation between the damping values and the identified parameters. Regression analysis was used to represent this relationship statistically.

A number of parameters were identified as influencing damping values: pipe diameter, type of support, number of supports, stress level, frequency, and mode number. Among these, pipe diameter and stress level are used in Regulatory Guide 1.61. However, the engineering assessments performed on the data collected show very little relationship between damping values and these two parameters. A strong correlation appears to exist between damping and frequency, indicating in general that damping decreases as frequency increases. The regression analysis performed on the collected data suggested a statistical relationship between damping and frequency. Other parameters do not show strong correlation, except for mode number. In general, the mode number has an indirect relationship with frequency.

The PVRC piping committee recommended that damping values for piping design be defined solely as a function of frequency, independent of stress level and pipe size. The recommended median damping value is 5% of critical damping for piping frequencies up to 10 Hz and 2% for piping frequencies between 20 Hz and 33 Hz, with a linear variation between 10 and 20 Hz. No description is given for frequency beyond 33 Hz. This recommendation, which applies only to seismic design and is not currently proposed for other types of loads [Ref. 2-2], has been incorporated in ASME Code Case N-411.

2.2.2 Consultant Suggestions and General Discussion of PVRC-Proposed Damping

The PVRC recommendations and associated justification documents have been reviewed. The following technical discussions are offered:

1. Since the disclosure of the PVRC recommendation, many people in the technical community have expressed reservations about the frequency-dependent nature of the damping proposal. The reservations came either from personal technical opinion or from concern over introducing yet one more element into the already complex piping design procedure. Most people felt that a constant damping would be more suitable. However, the recommendation does serve one very important purpose, i.e., to encourage industry to design more flexible (or less rigid) piping systems. Because flexible systems will have lower frequencies, piping designers could analyze such systems using the higher damping. This incentive may help achieve the goal of more flexible piping design, which in turn would increase piping reliability during normal operation. A Lawrence Livermore National Laboratory (LLNL) survey funded by NRC indicated that a majority of PWR and BWR piping systems have fundamental piping frequencies under 10 Hz for seismic motion (Appendices A through D).

2. The recommended damping values are based on the median distribution of the collected data; uncertainty was not incorporated in developing the recommendation. After reviewing the raw data that went into the data evaluation, it is clear that the form of the data available from laboratory or in situ tests is not suitable for an uncertainty study. To incorporate uncertainty into the damping study would require a new set of tests designed with an uncertainty evaluation in mind. Therefore, the uncertainty issue will have to be addressed by other means.
3. The recommendation was made as an interim position. It was understood that the PVRC committee will continue its effort to produce a final version of its recommendation on damping values. It is not known whether future recommendations will be of the same magnitude, shape, or dependency as now recommended. If the NRC adopts this interim position, a question remains about what will be done if the final recommendation differs from the interim position. Many plants would then have piping systems already designed according to the proposed interim damping values.

The results of a study funded by the NRC to evaluate the PVRC-proposed damping values indicated substantial reductions in piping responses when the proposed damping was used. The reduction in responses ranged from 20% to 40% of the original dynamic responses due to seismic loads. The responses covered by this sensitivity study were acceleration, displacement, forces, and moments for both piping and support structures resulting from piping excitation under seismic load. As a result of the response reduction, it was found for one piping system under study that 9 seismic restraints out of a total of 12 could be removed while still meeting ASME Code requirements [Ref. 2-3].

A separate study also performed by the LLNL showed that the new design with fewer seismic restraints had equal or even higher reliability than the original stiff system when seismic and thermal loads were considered simultaneously [Ref. 2-4]. This study confirmed the desirability of having a more flexible piping system.

The following arguments are offered to answer the concerns expressed above:

1. Damping is a hypothetical factor used to represent the energy dissipation in a structure. Because of the complexity of predicting dynamic behavior mathematically, damping values are not something that can be defined with precision. A precise definition of damping may never be achievable. Therefore, we view damping as a mechanism representing a calibration of the design process. This calibration will help us to more realistically represent structural behavior mathematically.
2. Considerable calculational margin now exists in response spectra analyses. An LLNL study funded by the NRC calculated factors ranging from 2 to 32 for the three systems evaluated [Ref. 2-3] when piping response predictions using current standard review plan (SRP) seismic design procedures were compared against the best-estimate evaluations. The best-estimate evaluation model was based on a multiple-support time-history analysis, including uncertainties associated with each major parameter in the seismic analysis except for piping system parameters.

Pipe damping values did not deviate from the current requirements given in Regulatory Guide 1.61. If the actual damping were higher than that given in Regulatory Guide 1.61, the factors would be even higher than those reported.

3. A second part of this LLNL study used the PVRC-recommended damping values. A seismic evaluation was performed according to SRP procedures, the only difference being that the damping values for the piping system were different from those of Regulatory Guide 1.61. The same three systems were used in the study. The results in responses showed a reduction in dynamic response of up to 40% compared to those calculated using the original damping values. The reduced responses are used to make a comparison with the best-estimate multiple-support time-history analysis with damping for piping specified by Regulatory Guide 1.61. The comparison gave factors that ranged between 1.1 and 5.0 for the same three piping systems studied. The conclusion of this study is that we can use the PVRC-proposed new damping values to remove a significant amount of conservatism embedded in the current SRP seismic design procedure.

2.2.3 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations regarding damping values for piping design:

- o Action Items
 - Immediately endorse ASME Code Case N-411 for use in calculating seismic response using spectral analysis methods. (This limited endorsement does not apply to damping values for time-history analysis.)
- o Change in Regulatory Position
 - Revise Regulatory Guide 1.61 and SRP Section 3.9.2 to incorporate the new damping criteria.
- o Research Programs
 - Complete the Idaho National Engineering Laboratory (INEL) damping tests, which should establish more precisely the dependency of damping to both modal response frequency and load frequency.
 - Investigate the possibility of applying the PVRC damping position to dynamic loads other than seismic, and address proper damping for frequencies above 33 Hz.

2.3 Spectra Modification

Regulatory Guide 1.122 stipulates that the peaks of floor response spectra used for piping design input be broadened by $\pm 15\%$ to account for uncertain structural

frequencies resulting from uncertainties in parameters such as material properties of the structure and soil, damping values, soil-structure-interaction analysis techniques, and approximations in modeling techniques used in seismic analysis. In reality, a piping system will excite at only one peak frequency in the artificially broadened range. The required $\pm 15\%$ peak broadening artificially increases the total energy input to the piping system. Therefore, this requirement introduces additional conservatism into the seismic piping design. A more rational way of treating uncertainties while also maintaining consistency within standard design practice is to envelop responses instead of enveloping seismic input. In this way, additional artificial energy would not be introduced into the system.

2.3.1 PVRC Effort on Spectra Modification

The PVRC piping committee looked into the problem of spectra development and proposed that an alternative to peak broadening be allowed. The proposed alternative scheme has also been approved by ASME as an official position and incorporated in the ASME Boiler and Pressure Vessel Code. Code Case N-397 was filed with ASME and was approved. The proposed resolution will appear in Appendix N to the ASME Boiler and Pressure Vessel Code.

The proposed spectral peak shifting method requires that the results of shifted spectra be enveloped, thus enveloping the responses to different inputs rather than the inputs themselves. The proposed alternative method calls for shifting the unbroadened raw spectrum within the $\pm 15\%$ frequency range. Analyses would be performed at the peak frequency, at both ends of the $\pm 15\%$ range, and at all piping frequencies within the $\pm 15\%$ range. The final piping design response would then envelop results from all analyses. Reference 2-5 gives a detailed description of the proposed alternative method.

2.3.2 Consultant Suggestions and General Discussion of Spectra Modification

The PVRC recommendations and the associated supporting documentation have been reviewed. The following technical discussions are offered:

1. In the existing Regulatory Guide 1.122, the $\pm 15\%$ peak broadening requirement was used to account for uncertainty in predicting the natural frequencies of supporting structures. This uncertainty covers elements such as material properties of the structure and soil, damping values of soil and structure, soil-structure-interaction analysis techniques, and approximations in modeling techniques used in seismic analysis. In a recent research program funded by the NRC, the Seismic Safety Margins Research Program (SSMRP) [Refs. 2-6, 2-7, 2-8], a quantification of uncertainty was estimated for the various elements considered to have uncertainty. The combined uncertainties of all elements cited indicated that the uncertainty range can be much larger than $\pm 15\%$. The inadequacy of $\pm 15\%$ to cover all the uncertainties is not an issue of the proposed alternative method but exists in the original Regulatory Guide 1.122. However, in reviewing the technical justification that went into the original Regulatory Guide 1.122, it is clear that the NRC recognized the inadequacy of the $\pm 15\%$ range. The reason for specifying $\pm 15\%$ was to take into consideration the substantial conservatisms embedded in the SRP

seismic design methodology chain. It was assumed that the conservatisms embedded in the design process would compensate for the inadequacy of the $\pm 15\%$ broadening range. Because the NRC is working to remove overlapping conservatisms from the existing design procedure, it is necessary that the adequacy of the $\pm 15\%$ range be investigated.

2. The proposed alternative method calls for shifting only the first peak. Sometimes the second peak may be equally important for certain characteristics of the piping system.
3. The proposed alternative method calls for multiple piping analyses. The increased analytic effort associated with peak shifting compared to peak broadening may make its implementation more costly. Therefore, it would be left to industry to decide which approach to take, based on cost-benefit considerations.

The possible inadequacy of $\pm 15\%$ shifting range is recognized. This is a generic problem associated with the proposed shifting method that challenges existing Regulatory Guide 1.122. Unless a detailed study is done to precisely define what the actual uncertainties associated with the prediction of support structure frequency are, it would be difficult to judge whether or not the $\pm 15\%$ range is adequate.

The NRC funded an LLNL study [Ref. 2-3] to assess what the effect would be if this proposed alternative method is used in the actual piping design. The study indicated that up to a 10% reduction in dynamic response is to be expected by adopting this proposed method. For some systems the reduction may not be recognizable. This is a small effect compared to the overall seismic safety margins embedded in the current SRP seismic design methodology chain.

The increased analysis costs associated with this proposed method of peak shifting are recognized, especially when multiple independent spectra input is used or in cases where more than one dominant peak exists within the broadened frequency range. Since it is an alternative method, it will be left to industry to decide whether to use peak broadening or peak shifting, based on cost-benefit considerations.

2.3.3 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations regarding spectra modification:

- o Action Items
 - Immediately endorse ASME Code Case N-397.
 - Initiate NRC internal review regarding the adequacy of the $\pm 15\%$ range for treating uncertainties in spectral peak frequencies.
- o Change in Regulatory Position
 - Revise Regulatory Guide 1.122 to permit peak shifting as an alternative to peak broadening.

o Research Programs

- Assess uncertainty range of spectral frequencies, including uncertainties in piping system modeling.
- Develop a simple spectra-broadening procedure based on equivalent energy input.

2.4 Nozzle Load Design Limit

Terminations of piping systems quite often consist of nozzles in pressure vessels and tanks or nozzles of rotating equipment such as pumps or steam turbines in branch connections to run pipe. The specified allowable loads on nozzles are often so low that they require additional restraints on the piping. Also quite often the nozzles are modeled as rigid anchors in the piping system analysis. In some cases, the flexibility of nozzles in vessels and piping is very significant; the combination of using low allowable loads and ignoring nozzle flexibility may lead to a significant number of restraints that, by using a more rational approach, could be shown to be unnecessary.

2.4.1 Consultant Suggestions and General Discussion

While there are several SRP sections (e.g., 3.7.1, 3.7.2, 3.7.3, and 3.9.3) that address seismic analysis, none of these effectively address the problem of nozzle loads. (Nozzle loads are significant with respect to static loads such as weight or thermal expansion. However, there are no regulatory criteria relevant to the evaluation of static loads.)

The combination of using low allowable nozzle loads and ignoring nozzle flexibility may lead to additional restraints which, by a more rational approach, could be shown to be unnecessary. These additional restraints may reduce the reliability of the piping system and will add to its cost.

Nozzles in Vessels

Stresses in vessels at nozzles subjected to moment loading are often estimated by using Welding Research Council Bulletin 107 [Ref. 2-9]. However, realistic limits for these estimated stresses have not been established, particularly for Level D service loadings. Bulletin 107 does not give any information on stresses in the nozzles (it gives stresses in the vessel at the nozzle), nor does it give any information on the flexibility of the nozzles.

The PVRC Subcommittee on Reinforced Openings and External Loadings is sponsoring analytical and test work on nozzles in cylindrical shells with moment loads on the nozzle. The analytical work completed to date has been performed by C. R. Steele and is summarized in References 2-10, 2-11, and 2-12. Test data that have been developed recently, in large part for the purpose of comparisons with Reference 2-11 theory, are contained in References 2-13, 2-14, and 2-15. WRC Bulletin 297 [Ref. 2-16] has been recently published. This bulletin, based on Steele's analytical results, is an extension of WRC Bulletin 107 [Ref. 2-9] in that it gives stresses in both the vessel adjacent to the nozzle and in the nozzle adjacent to the vessel. It also gives data from which the nozzle flexibility (or stiffness) can be obtained.

Nozzles in Piping

The ASME Code [Ref. 2-17] for Class 1 piping gives specific guidance for calculating stresses, stress limits, and flexibility of nozzles in piping (i.e., branch connections). Analogous specific guidance for calculating stresses and stress limits are also given for Class 2 or 3 piping, but flexibility is not included.

The work discussed above for nozzles in vessels may have some impact on nozzles in piping. However, there are no efforts under way to modify or expand the guidance given in NB/NC/ND-3600 of the Code [Ref. 2-17].

Nozzles on Rotating Equipment

Allowable loads for nozzles on rotating equipment (e.g., pumps and turbines) are established in such standards as NEMA SM23 [Ref. 2-18] for steam turbines and API-610 [Ref. 2-19] for centrifugal pumps. As indicated in Table 2-1, the allowable loads in NEMA SM23 correspond to very low limits on pipe stresses. Allowable pipe stresses (SA106 Grade B, temperatures below 650°F, Class 2 or 3) are from 22.5 to 37.5 ksi for displacement-controlled loadings.

Specifications for nuclear power plant rotating equipment usually include a portion that indicates the nozzle loads that the Buyer wishes to have accepted by the Seller. Limits on pipe stresses for one such specification-portion are shown in Table 2-1 and identified as S_2 . These are more liberal than NEMA SM23 [Ref. 2-18] limits, but even these more liberal nozzle load limits will often lead to additional restraints on the piping. Furthermore, the Seller may not accept the specification loads, which causes time-consuming and costly negotiations between the Buyer and Seller.

A major problem with allowable nozzle loads on rotating equipment is that the basis for establishing those loads is not generally known, e.g., the basis for either NEMA SM23 [Ref. 2-18] or API-610 [Ref. 2-19] allowable nozzle loads.

The PVRC Subcommittee on Piping, Pumps, and Valves is sponsoring work on allowable loads on pump nozzles. The long-range objectives are to:

1. Gain improved understanding of the relationships between connecting piping pump load patterns and the pump failure modes experienced in the process and power industries, primarily through the accumulation and evaluation of field data.
2. Establish, through actual field experience, what margin is provided between "safe" load and "overload" by current design criteria.
3. Propose, for consideration by the appropriate standards-making bodies, improved and extended criteria as are indicated and warranted by the conclusions of these efforts.

Table 2-1

LIMITS ON STRESSES IN STANDARD WEIGHT PIPE ATTACHED TO ROTATING EQUIPMENT NOZZLES

Nominal Pipe Size (NPS)	Pipe Wall Thickness, t, in.	Pipe Section Modulus Z, in ³	Limits on Pipe Stresses		
			S ₁ , ksi (a), (b)	S ₂ , ksi (a), (c)	S ₃ , ksi (d)
2	0.154	0.561	21.4	12.6	14.8
4	0.237	3.22	7.47	9.39	7.45
6	0.280	8.50	4.24	6.48	4.94
8	0.322	16.81	2.86	6.70	3.71
10	0.365	29.91	1.74	5.83	2.65
12	0.375	43.8	1.28	4.76	2.25
16	0.375	70.3	0.91	3.87	-

(a) Based on the assumption that forces imposed on the equipment by the attached pipe are negligible. If forces are not negligible, the limits on stresses would be reduced to less than the tabulated values.

(b) NEMA Steam Turbine Standard SM23-1979:

$$S_1 = 12 \times 3 \times 167 D_e / Z$$

D_e = NPS for NPS of 8 and smaller

D_e = (16 + NPS)/3 for NPS of 8 and larger

(c) Limits from a Buyer's specification for centrifugal pumps:

$$S_2 = 180,000 D_x^2 t / (bZ), \text{ where } D_x \text{ and } b \text{ depend upon NPS as follows:}$$

NPS	4 & under	6 to 8	10 & over
D_x	NPS + 1	NPS	(NPS + 16)/3
b	35.29	32.94	28.23

(d) Limits from API-610, Appendix C, Table C-1, $S_3 = M_r / Z$. M_r = resultant moment from Table C-1. Stresses are based on the assumption that the resultant force is equal to its allowable per Table C-1. If the resultant force is negligible, the allowable stresses can be doubled, for NPS ≤ 6 , and can be increased by about 50% for larger NPSs.

These objectives, when accomplished, should provide a significant step in rationalizing allowable nozzle loads on rotating equipment. However, this work does not address allowable loads on steam turbines. Also, it appears likely that emphasis will be placed on continuous loads, and suitable criteria for short-time loads (e.g., water hammer, earthquakes) may not emerge.

Static Load Criteria

There are no SRP sections that address static loadings. Static internal pressure is, in many piping systems, the most important of all loadings. The ASME, in NB/NC/ND-3640, gives adequate guidance. However, because no SRP sections address this important subject, it appears that NRC plant reviews have not established that the Code NB/NC/ND-3640 requirements have been met.

For pressure loading, the SRP should address the following items:

1. Corrosion/erosion allowance
2. Minimum wall thickness control during fabrication
3. Design of fabricated branch connections
4. Effect of lugs, trunions, and heavy clamps on pressure boundary

Up to the present time, weight and restraint of thermal expansion loads have been of minor significance because of design control by seismic loadings. However, the work in progress by the PVRC Committee on Piping Systems and/or implementation of other recommendations made in this report may greatly reduce the significance of seismic loadings on piping pressure boundary integrity (including equipment nozzles) and on piping supports. When this stage is reached, the accuracy of analysis for weight and restraint of thermal expansion will become more significant. For these loadings, the SRP should address the following items:

1. Appropriate use of stress indices and stress intensification factors for piping products covered by the Code
2. Development and appropriate use of stress indices and stress intensification factors for piping products not covered by the Code
3. Effect of overthickness elbows
4. End-effects on elbows
5. Flexibility of nozzles
6. Adequacy of piping system analysis

The recommended new SRP is not intended to add any requirements that are not contained in the Code. Rather, it is intended to be a checklist whereby the NRC obtains assurance that Code design requirements have been met.

2.4.2 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations with regard to nozzle design:

o Action Items

- Request that the ASME Section III Working Group on Piping Design revise ASME Code sections addressing pipe system flexibility

calculation to also consider tank and vessel nozzle flexibility.
(Completed)

o Change in Regulatory Position

- Revise SRP Section 3.9.2 to consider nozzle flexibility in piping analysis.

o Research Programs

- Develop improved design guidance on nozzle stress limits and flexibilities.

2.5 Inelastic Piping Response and Modifications to Elastic Analysis Criteria

2.5.1 Consultant Views and Information

Current practice for the seismic design of piping does not correlate well with experience on the behavior of piping in seismic events. Piping design concentrates on inertial loads and inertial-induced primary stresses held to Code-allowable stress limits. These stress limits have been set to prevent plastic instability or excessive ovaling (excessive flow area reduction) based on static load tests. A static load test does not recognize that seismic input is a short duration, limited-energy-content, oscillatory input. Whereas a static mechanical load continues to strain the pipe until either failure occurs or until sufficient static resistance is developed, an oscillatory, short-duration, dynamic input results in increased limits on strain in which for short periods of time the load exceeds the ultimate resistance of the pipe.

Most heavy industrial facility or power plant piping is generally thickwalled (diameter to thickness ratio less than 35). For such piping, past seismic experience [Ref. 2-20] has never shown a primary collapse mode of failure. Seismic failures of thickwalled ductile steel piping with butt-welded joints have been caused by:

1. Excessive support movements that pulled the pipe apart.
2. Rupture associated with an initial flaw or excessive erosion or corrosion.

Failures due to support movement have resulted from lack of sufficient flexibility in the piping system. Examples are cases of a straight pipe header running between inlet nozzles of two adjacent tanks or a straight small-diameter branch pipe running between two large-diameter pipes. In these cases, differential shaking displacements of the tank or the large-diameter pipe rip apart the straight connecting pipe.

A limited amount of nonlinear piping analyses [Refs. 2-21 and 2-22] have also demonstrated that a primary collapse failure mode is highly unlikely. Essentially, a very large margin exists against primary collapse for limited-energy dynamic events. Analytical studies reported in Reference 2-22 identify plastic strain ratchetting as the controlling failure mode, rather than plastic collapse, for piping with fundamental frequencies above the 1 to 5 Hz range.

The primary problem is that piping systems are capable of absorbing and dissipating a considerable amount of energy when strained beyond their elastic limit. On the other hand, an earthquake is capable of inputting only a limited amount of energy into such systems. Unless corrected for inelastic response capability, a linear-elastic response analysis is incapable of accounting for the inelastic energy absorption capacity even when Service Level C or D stress criteria are used. The energy absorption obtained from a linear-elastic analysis carried to Service Level C or D stress levels is only a fraction of the total energy absorption capability of the piping system [Ref. 2-21].

The net result is excessive conservatism in the treatment of primary stresses when uncorrected linear-elastic analyses are performed and the results are compared to stress limits based on static tests. In turn, this excess conservatism in the treatment of primary stresses leads to the use of pipe supports in excess of what is needed to provide acceptable margins against failure for dynamic loads that may occur. These additional supports decrease the reliability of piping systems for normal operating loads as thermal growth is potentially overrestrained.

A significant aspect of nuclear power plant piping system design is that there are typically 100 to 200 systems that must be evaluated. Each of these systems contains lengths of straight pipe and may contain elbows, bent pipe, reducers, branch connections, flanged joints, etc. A rigorous elastic-plastic analysis of any one of these systems would constitute a major undertaking. Indeed, in the relatively simple geometry/loadings of an elbow, test data [Ref. 2-23] indicate that there are significant finite-displacement effects; the present Code [Ref. 2-17] incorporates this effect in an approximate manner by making the B_1 -index a function of the elbow parameter, h . To capture this complex interaction between internal pressure and moment loading, the analysis would need to be an elastic-plastic, finite-displacement, dynamic method.

The near-term application of elastic-plastic analysis of piping systems is useful for understanding and calibration of elastic analysis methods. References 2-21 and 2-24 represent valuable recent contributions along these lines. The NRC should encourage further work of this type and, even though it will entail additional work for the staff in safety evaluation report (SER) reviews, elastic-plastic analysis methods should be accepted for specific evaluations.

However, in the near-term for "production" evaluation of piping systems, elastic analysis will continue to be used. This subsection discusses potential changes in Code criteria. When used with elastic piping system analysis, the changed criteria would be more realistic for seismic loadings.

Existing Regulatory Positions on Seismic Design of Piping

Appendix A to SRP Section 3.9.3 specifies the load combinations, which include seismic (SSE or OBE), shown in Table 2-2.

Table 2-2
STANDARD REVIEW PLAN LOAD COMBINATIONS

Service Loading Combination*	Service Stress Limit
Sustained Loads + LOCA + SSE	D
Sustained Loads + DBPB + SSE	D
Sustained Loads + MS/FWPB + SSE	D
Sustained Loads + SOT + OBE	B

*LOCA	=	Loss-of-coolant accident
DBPB	=	Design basis pipe break
MS/FWPB	=	Main steam and feedwater pipe break
SOT	=	System operating transient

In addition to meeting the specified service stress limits, operability and functional capability must also be demonstrated.

The present ASME Code criteria, with respect to seismic design of piping pressure boundaries, consists of two checks:

1. Satisfaction of Code Equation (9)

$$B_1 P D_o / 2t + B_2 M_x / Z \leq \alpha S_x$$

The stress limits of Code Equation (9) are provided in Table 2-3. M_x , in general, is a resultant moment amplitude. See the Code for definition of other terms.

2. Satisfaction of fatigue criteria (explicit for Class 1; implicit for Class 2/3)

Table 2-4 indicates how moments due to seismic loads are included in the evaluations. The seismic-induced moments are further classified as those due to seismic inertia (SI) or those due to seismic anchor movements (SAMs).

The treatment of primary and secondary stresses is different at Service Level D than it is at Service Level B. First, secondary stresses (SAM) can be ignored at Service Level D. In light of the fact that SAM has resulted in piping failures in past earthquakes, ignoring of SAM stresses for the SSE appears to be questionable. However, so long as the OBE SAM stresses are at least 50% of the SSE SAM stresses and so long as OBE SAM must be combined with restraint of thermal expansion stress at Service Level B, this ignoring of SSE SAM poses no problem.

The SSE SI stresses combined with other primary stresses can be compared either with the primary stress allowables of Equation (9) of the ASME Code or against the criteria of Appendix F to the ASME Code. When Equation (9) is used, an elastic piping system analysis is performed. With Appendix F, either an elastic

Table 2-3
CODE EQUATION (9) STRESS LIMITS

Level	αS_x is lesser of:	
	Class 1	Class 2
A	---	$1.8S_h, 1.5S_y$
B (OBE)	$1.8S_m, 1.5S_y$	$1.8S_h, 1.5S_y$
C	$2.25S_m, 1.8S_y$	$2.25S_h, 1.8S_y$
D (SSE)	$3.0S_m, 2.0S_y$	$3.0S_h, 2.0S_y$

Table 2-4
INCLUSION/NONINCLUSION OF SEISMIC MOMENTS IN PIPING PRESSURE
BOUNDARY EVALUATION

Level	Code Equation (9)				Fatigue Evaluation			
	Class 1 ^(a)		Class 2		Class 1		Class 2	
	SI (b)	SAM (b)	SI	SAM (c)	SI (b)	SAM (b)	SI	SAM (c)
A	--	--	Yes	Yes	Yes	Yes	No	Yes
B(OBE)	Yes	No	Yes	Yes	Yes	Yes	No	Yes
C	Yes	No	Yes	No	No	No	No	No
D(SSE)	Yes	No	Yes	No	No	No	No	No

(a) Code Equation (9) is not used for Level A, Class 1 piping.

(b) For Class 1 piping, the Code does not distinguish between SI and SAM moments. The entries under Code Equation (9) are deemed to agree with industry practice. The "Yes" entries under Fatigue Evaluation are also deemed to agree with industry practice. However, the "No" entries under Fatigue Evaluation are definite in the sense that NB-3655 and NB-3656 of the Code do not require fatigue evaluation for Level C or D.

(c) For Class 2 piping, SAM may be considered either in Code Equation (9) or the implicit fatigue evaluation of NC-3653.2. SI moments are not required to be included in fatigue evaluation.

or a plastic piping system analysis may be performed. However, even when a plastic system analysis is performed, the acceptance criteria consist of comparing computed stresses or loads with static allowable stresses or static allowable loads. Thus, the advantage of accounting for inelastic energy absorption due to nonlinear hysteresis loops under dynamic loading cannot be fully achieved because of a lack of an allowable strain criterion and the use of static allowable stress or load criteria.

Some Data Relevant to Code Criteria

1. Experiences with Piping Systems During Earthquakes

A large amount of piping is used in such industrial installations as fossil-fueled power plants and oil refineries. Some of these installations have been subjected to very severe earthquakes. The NRC has funded a report of this experience that is presented as an addendum to Volume 2 of NUREG-1061 [Ref. 2-20].

Inspection of the piping systems that had been subjected to severe earthquakes indicates that no failure of the inertia type that ASME Code Equation (9) is supposed to protect against has occurred. Of course, when portions of a building structure fall on the pipe or carry the pipe with them as they fall, the pipe may be badly bent or ruptured in the process. But this is not the type of failure encompassed by Code Equation (9).

At this time, we can only say that Code Equation (9) appears excessively conservative and that Code consideration of SAMs is inadequate.

2. Earthquake Simulation Tests

EPRI and the NRC have sponsored tests at ANCO of simple piping systems consisting of (1) a Z-bend, (2) a three-dimensional piping system with two anchors, and (3) a three-dimensional piping system with two branches and four anchors. The pipe material is SA 106 Grade B. Reference 2-25 gives some results of the Z-bend test. A to-be-published paper, Reference 2-26, gives a much more complete description of the Z-bend test results. Reference 2-27 gives some results from the three-dimensional two-anchor piping system. While References 2-25 and 2-27 contain only brief abstracts of test results and even Reference 2-26 is missing vital information from the standpoint of evaluating Code criteria, there are *prima facie* aspects of the tests that are relevant.

- a. Test inputs of about four times the level estimated to correspond to the Code Equation (9) Level D did not cause any gross plastic deformation of the piping systems. This suggests that Code Equation (9) is conservative.
- b. The four-times-Level-D tests of the Z-bend contained acceleration inputs, at the major piping frequency response of 7.3 Hz, of about 25g. This input acceleration is very high compared to most nuclear power plant floor response spectra and enforces the field experience; SI moments are very unlikely to significantly damage piping made of material like SA 106 Grade B.

Generalization of the ANCO test results with respect to Code Equation (9) poses several problems. First, it appears that these are tests of Code Equation (9) with respect to elbow strength. That is, even in the four times Level D tests, it appears that loads on straight pipe portions were not above the strength expected from static load tests. However, for the Z-bend four-times-Level-D test (with guesses that the elbow thickness was about nominal and the elbow material yield strength did not exceed 50 ksi), it appears that maximum loads were about two times the expected-from-static-tests load capacity. With available data from the three-dimensional two-anchor system, it is not possible to state for sure that the four-times-Level-D test imposed loads that were greater than expected-from-static-tests load capacity.

Further study of the ANCO tests is needed. Also, we need to study the implications of these tests with respect to applicability of elastic piping system analysis for calculating loads. The prima facie aspects of the tests suggest that Code Equation (9) is excessively conservative.

3. Teidoguchi Dynamic Tests

Teidoguchi [Ref. 2-28] reported results of tests in which five Z-bend piping systems were mounted on a shake table and vibrated at the resonance frequencies of 2.8 Hz (out-of-plane, three tests) or 3.6 Hz (in-plane, two tests). One of the out-of-plane tests was run with zero internal pressure; the other four were run with internal pressures such that the nominal hoop stress, $PD/2t$, was about 18 ksi. The material was an austenitic steel, like Type 304, but the yield strength of the material is not stated.

The maximum moment amplitudes during these tests ranged from 2.5 to 3.6 times that permitted by Code Equation (9) with a Level D stress limit of $2S_y = 60$ ksi. Estimating that the material used in the test specimens has a yield strength of 40 ksi leads to estimates that the maximum moment amplitudes ranged from 1.5 to 2.1 times the expected static limit moment.

Each of these five tests were terminated by a fatigue failure (through-wall crack) in the body of an elbow. Cycles-to-failure ranged from 108 to 340. In the four tests with internal pressure, measurable ratchetting occurred. However, the Code fatigue analysis methods include the effect of ratchetting, and the cycles-to-failure in these tests is reasonably consistent with the bases for both Code Class 1 and Class 2/3 fatigue evaluation methods.

Problem Areas with Current Practice

Two potential problems exist with the current practice for seismic design of piping systems.

1. The practice of comparing inertial-induced stresses or loads with primary static stress or load limits results in excessive conservatism in the treatment of inertial effects because it ignores the limited-energy input and the inelastic energy absorption capability of the piping system. The reality that inertial effects have not failed thickwalled ductile steel piping is being ignored by this practice. This practice encourages the overrestraint of piping.

2. The practice of treating seismic support movement as secondary stresses and thus ignoring these stresses at Service Level D is potentially unconservative unless an OBE of at least 50% of the SSE is considered. Excessive differential support movement has failed overrestrained piping. One should be encouraging flexibility of piping between anchor points to prevent such failures. However, ignoring such stresses while overemphasizing inertial-induced stresses encourages overrestraint and lack of flexibility.

These two problems (overconservative treatment of inertial effects and potentially unconservative treatment of SAMs) can be overcome by the use of strain or displacement criteria in lieu of linear-elastic computed stress or force criteria. It is large inelastic strains (not stresses) that can lead to tensile rupture, compressive wrinkling, or excessive ovaling. When evaluated on a strain basis, the pipe doesn't care whether the strains are due to inertial effect or seismic anchor movements. The distinction between inertial responses and anchor movements is of interest only when a stress analysis is performed for comparison with static stress or load allowables.

2.5.2 Consultant Suggestions for Changes in Regulatory Positions

The NRC staff should allow any of these three approaches: (1) the current SRP Section 3.9.3 service stress limit approach with the ASME Code, (2) an alternative performance criterion to demonstrate the seismic adequacy of piping systems for the SSE, or (3) the modifications to elastic analysis criteria given in Section 2.5.3.

With the current service stress limit approach, one should either require that $1/2$ SSE SAM combined with thermal expansion stresses meet Service Level B secondary stress limits (Equation (10) of the Code) or should establish some alternative stress limits to be used with SSE SAM. In this way, one explicitly guards against SAM-induced piping failures at the SSE level. Thus, one would not have to consider an OBE to guard against SSE SAM.

As an alternative performance criterion for the SSE, the NRC staff should establish a minimum required factor of safety against failure for the SSE combined with other loadings. We recommend a minimum SSE factor of safety of 1.5 to 2.0. A minimum SSE factor of safety of 1.5 to 2.0 is sufficient to provide a margin for ground shaking greater than the SSE and response uncertainties. Actually, additional seismic margin exists because of conservative building response analysis and conservative definition of the seismic input motions.

Failure would be defined as either (1) onset of plastic tensile instability (onset of tensile necking), (2) low-cycle fatigue (less than 5 full cycles), (3) onset of compressive wrinkling (local buckling), or (4) excessive deformation resulting in more than a 15% reduction in cross-sectional flow area. The applicant should be permitted to perform nonlinear seismic time-history analyses of a piping system to demonstrate compliance with this performance goal. One method is to factor all loads upward by the required minimum safety factor of 1.5 to 2.0 and demonstrate that the computed strains from these factored loadings are less than those associated with any of the failure modes. Both SI and SAM effects should be required to be included in this alternative approach.

This alternative performance criterion has the major advantage of allowing an applicant to properly account for the inelastic energy absorption capacity of a piping system and to properly compare both SI and SAM effects against strain criteria. The drawbacks are:

1. Nonlinear seismic time-history analyses would have to be performed.
2. Failure strain criteria would have to be established.

A substantial static failure test data base exists for pipe failing by tensile plastic instability or by compressive wrinkling. When strained in tension, pipe is very ductile and is capable of mobilizing large strains, with significant tensile yielding before rupture. The basic pipe material can withstand strain of at least 10% to 17% in tension, depending on the pipe material. However, stress concentrations due to weld discontinuities and nonuniformities in pipe wall thickness, yield point, etc., could lead to pipe failure at lower strain levels. Thus, the maximum tensile strain in the pipe should be kept well below the ultimate strain capacity of the steel. With good quality control to promote near uniformity of pipe properties and weld inspection adequate to minimize weld flaws, maximum design tensile strain limits on the order of 2% to 5% are reasonable [Ref. 2-29].

When a pipe is strained in compression, wrinkling of the pipe wall can occur because of local buckling. Experimental results of Wilson and Newmark [Ref. 2-30] indicate that actual cylinders will normally begin to wrinkle at strains of about

$$\epsilon \cong 0.2 (t/R)$$

where t is the wall thickness and R is the pipe radius. Tests on large-diameter pipe indicate somewhat greater wrinkling capacities. For instance, Reference 2-31 reports that for 48-inch diameter, 0.462-inch wall thickness pipe, wrinkling begins at a compressive strain of 0.004 to 0.007. Furthermore, wrinkling does not imply failure. Strains of the order of four to six times as great, in the absence of severe stress raisers or flaws, can normally be sustained without danger of tearing at the compression wrinkle. It should be recognized, however, that after wrinkling occurs, further strains may tend to concentrate in the area of the wrinkle.

Therefore, the following strain criteria are sufficient to conservatively prevent failure in straight pipe from tensile plastic instability, low-cycle fatigue, or compressive wrinkling:

$$\epsilon \leq 0.2 (t/R)$$

or

$$\epsilon \leq 0.02$$

(1)

whichever is less. A significant but lesser data base exists for failure strains in fittings and strains associated with flow area reduction.

This alternative performance criterion would generally not be used in the near future because of costs associated with nonlinear time-history analysis and uncertainty concerning failure strain criteria. However, the primary purposes of this alternative criterion are:

1. Establish an acceptable minimum margin of safety for seismic design of piping. It should be noted that the actual seismic margin associated with the SSE will be larger than this minimum design margin because of additional margin provided by conservative building response analysis and conservative definition of the input motions.
2. Encourage research to establish conservative failure strain criteria for piping components.
3. Encourage research to establish acceptable pseudolinear-elastic seismic analysis methods that conservatively approximate the results of nonlinear time-history seismic analysis. Such techniques may incorporate the use of dynamic-to-static margin ratios to modify linear-elastic response results. Alternatively, such research might result in increased allowable stresses for dynamic input and linear-elastic analysis.
4. Provide an alternative means to encourage more flexible (less restrained) piping design and to demonstrate the acceptability of such designs even though current ASME Code criteria are not met.

2.5.3 Consultant Suggestions for Revising ASME Code Criteria for Seismic Stresses

In Item 1 below, the concept of removing SI and SAM moments from Code Equation (9), provided they both are included in a fatigue evaluation, is explored. Available data are deemed to be sufficient to defend such a change. However, as discussed in Item 2, this leads to potential problems in calculated loads using an elastic piping system analysis. In Item 3, a proposed relaxation in Code Equation (9) stress limits is presented. The problem of axial stresses in piping is discussed in Item 4.

1. Concept

This concept consists of removing SI and SAM moments from Code Equation (9), provided both are included in a fatigue evaluation [Ref. 2-22].

Class 1 Piping

Table 2-4 shows that OBE moments are already included in a fatigue evaluation. Extending the concept to SSE leads to the potential Code change:

M_i need not be included in Code Equation (9) provided it is included in the fatigue evaluation, where M_i is the SI and SAM moment resultant from either SSE or SAM.

Of course, a fatigue evaluation requires an input of a number of stress cycles. For OBE evaluations, piping analysts must have made some postulation of the number of stress cycles. Extension to SSE will require the same sort of postulation. While it is not our purpose to pin down this cyclic-postulation, in our judgment, 50 maximum OBE cycles and 5 or 10 maximum SSE cycles would be sufficient. By "maximum," we mean the largest peak-to-peak stress range calculated for the particular OBE or SSE.

Class 2/3 Piping

Because Class 2/3 piping has implicit rather than explicit fatigue criteria, the pathway to implementing the concept of moving SI and SAM moments from Code Equation (9) to a fatigue basis is considerably more complex than for Class 1 piping. A brief discussion of the implicit fatigue basis of Class 2/3 rules is now given. For more detailed discussion of the fatigue basis of Class 2/3 rules, along with comparisons with Class 1 piping fatigue evaluation, see Reference 2-32.

The fatigue evaluation used for Class 2/3 piping is based on moment-loading fatigue tests on piping products reported in Reference 2-33 and Markl's correlations thereof. His cycles-to-failure equation is:

$$iS_f = 490 N_f^{-0.2} \text{ (ksi, range)} \quad (2)$$

where i = fatigue-based stress-intensification factor
 S_f = nominal stress range, M/Z, cycles to failure
 N_f = average cycles to failure (through-wall crack)

The i factors given in Figures NC/ND-3673.2(b)-1 are, for the most part, taken directly from Markl's recommendations.

For design purposes, a margin of two on stress was deemed appropriate; hence, the design equation is:

$$iS_d = 245 N_d^{-0.2} \text{ (ksi, range)} \quad (3)$$

where S_d = nominal stress range, M/Z, for design use
 N_d = design cycles

Correlations of Equation (3) with Code Equations (10) and (11) in NC/ND-3653.2 are discussed in Reference 2-32. The important points here are:

- a. The Code equations, by the use of $f = 1.0$ up to 7000 cycles, incorporate Equation (3) for not less than 7000 cycles of moment loading.
- b. Equation (3) was developed from tests on A106 Grade B piping products at room temperature but (in the absence of severe environmental effects such as stress corrosion cracking) gives equally applicable design guidance for temperatures up to 550°F and for austenitic steels at temperatures up to 550°F.

If, in analogy to the suggestion for Class 1 piping, the SI and SAM moments were to be removed from Code Equation (9) and placed in Code Equations (10) and (11), we would be designing for 7000 cycles of OBE and 7000 cycles of SSE. This is too conservative.

There are a number of possible approaches to incorporate the concept of moving SI and SAM moments from Equation (9) to fatigue evaluation control. However, one particular approach appears attractive because it would require a minimum of effort in Code revisions, in Code users' reeducation, and in NRC staff reviews.

This approach is based on the assumptions that:

- a. Five maximum SSE stress cycles and 50 maximum OBE stress cycles are realistic estimates, and
- b. The usage factors for OBE and SSE cycles should be small (we will use "small" as 1/16 for SSE cycles and 1/16 for OBE cycles).

Usage factor is defined as n_i/N_i , where n_i is the number of anticipated cycles of a given stress amplitude and N_i is the number of allowable cycles of that amplitude. Equation (3) then gives:

$$\begin{aligned} iS_d &= iM'_B/Z = 102 \text{ ksi stress range for SSE} \\ &= 64.4 \text{ ksi stress range for OBE} \end{aligned}$$

where M'_B is the resultant moment range due to SI and SAM.

The usage factors are related to the design Equation (3). As related to mean cycles-to-failure Equation (2), the usage factor is $1/(16 \times 32) = 0.002$ for SSE and OBE, a total of 0.004.

Code Equation (9) is an amplitude limiting equation. Accordingly, the appropriate limits to SI and SAM moment amplitude corresponding to the assumed cycles and usage factor are 51 ksi for SSE and 32 ksi for OBE. This leads to the potential Code change:

M'_B need not be included in Code Equation (9) provided (iM'_B/Z) does not exceed 51 ksi for SSE or 32 ksi for OBE. M_B is the maximum amplitude (one-half the range) of SI plus SAM moments.

2. Nozzle, Flanged Joint, and Support Loads

The elastic piping system analysis that is used to evaluate pressure boundary adequacy is also used to calculate nozzle, flanged joint, and support loads. The limits to Code Equation (9), shown in Table 2-3 were selected so that gross plastic deformations would be restricted and an elastic piping system analysis could be defended as usable to calculate loads. The potential Code criteria discussed in Item 1 may, of course, permit higher limits than shown in Table 2-3 and are intended to do so. The applicability of an elastic piping system analysis for calculating nozzle and support loads is no longer apparent.

What appears to be needed is a simple technique whereby the loads, for piping systems where Code Equation (9) limits are exceeded, would be scaled up. References 2-21 and 2-22, as well as the ANCO data, should be reviewed to see if a basis for such a technique can be found.

3. Code Equation (9) Stress Limits

As indicated in Table 2-3, the present Code limits are based on the lesser of a factor times the allowable stress and a factor times the yield strength. Because large plastic deformations are a function of material yield strength, the factor times yield strength is obviously pertinent.

Reference 2-34, which provided a basis and motivation for recent Code Equation (9) changes, suggested limits in terms of S_y only. This approach is deemed to be supported by results of the ANCO tests on SA 106 Grade B piping systems. Accordingly, it is appropriate to eliminate the allowable-stress-dependent limits of Code Equation (9), with a proviso discussed below.

Code Equation (9), with its limits of up to $2S_y$, involves an implicit assumption that the material is ductile, e.g., not like glass or cast iron. Typical piping materials such as SA 106 Grade B and SA 312 Type 304 are, of course, sufficiently ductile. In general, Code weld qualification requirements (e.g., bend tests) are sufficient so that welds in such materials are also reasonably ductile. However, the Code lists a welded pipe material, SA 672 J100, which has minimum ultimate strength of 100 ksi and yield strength of 83 ksi. We are not aware of the use of such a material for nuclear power plant piping but nevertheless the possibility exists. We would question the application of Code Equation (9), even with its present limits but particularly with S_y -related limits only, to piping made of a material like SA 672 J100.

Flanged joints often use SA 193 Grade B7 bolting, a material with properties somewhat like SA 672 J100. However, to be able to pass a hydrostatic test, it is necessary to tighten the bolts to high stress levels and subsequent loads (e.g., SI and SAM moments) should not increase the preapplied stress level. Appropriately, the Code addresses flanged joints separately from Code Equation (9).

The preceding leads to the suggested Code change:

The allowable-stress limits on Code Equation (9) should be eliminated provided that S_u/S_y is at least 1.5. (S_u = specified minimum U.T.S., S_y = specified minimum yield strength.)

This suggestion could be implemented immediately and could significantly reduce the number of seismic restraints required to meet Code Equation (9) for Class 2 or 3 ferritic steel piping such as SA 106 Grade B. Examples of the effect for Level D are shown in Table 2-5.

It may be noted that this is a further step towards making Code Equation (9) for Class 1 the same as for Code Class 2/3. With the proposed change, the stress limits and the left-hand side of Code Equation (9) become the same.

4. Axial Stresses in Piping

Failures have occurred in straight pipe running between inlet nozzles of two adjacent tanks and in straight pipe running between two large-diameter pipes. The addendum to this Volume 2 of NUREG-1061 [Ref. 2-20] gives some specific descriptions of these failures.

Table 2-5
PROPOSED CHANGES TO LEVEL D ALLOWABLE STRESSES

Material	Temp. (°F)	Class 1		Class 2/3	
		Present (ksi)	Proposed (ksi)	Present (ksi)	Proposed (ksi)
SA 106-B	100	60.0	70.0	45.0	70.0
	500	56.6	56.6	45.0	56.6
Type 304	100	60.0	60.0	56.4	60.0
	500	38.8	38.8	38.8	38.8

Piping codes, since their early drafts in the 1920s, have never required the axial stresses in piping to be limited in any way. This tradition has carried on into the Code for both Class 1 and Class 2/3 piping. Of course, in a piping system analysis, the forces are a basic part of the results. For straight pipe, the axial stress is simply F/A , where F is the axial force and A is the pipe cross-sectional area. However, for elbows, branch connections, tees, flanged joints, etc., evaluation of axial stresses might entail developing a set of stress indices and stress intensification factors analogous to those now available for moment loading. This is a major undertaking and should not be entered into lightly.

Reference 2-20 highlights these particular failures because they are of a type for which Code rules do not provide any evaluation. After thorough review of these failures (type of pipe, type of nozzles, estimated relative end displacements that caused the failures), it might be advisable to include this subject in SER reviews and perhaps even in reviews of operating plants.

One aspect of the problem is that nozzles in piping and pressure vessels will quite often undergo gross plastic deformations at radial loads that are much less than the axial load to produce yielding of the attached pipe. Further, even in the elastic region, the radial flexibility of nozzles is usually highly significant in realistic evaluation of axial loads. Keeping these aspects in mind, it may be possible to develop "screening criteria" that would evaluate the potential of piping failures due to excessive axial stresses arising from SAMs.

5. Regulatory Requirements

If the Code change proposed in Item 3 were adopted and if NRC accepts that Code Revision/Addenda, no specific changes are needed in regulatory documents such as SRP Section 3.9.3. However, the process of Code changes and NRC acceptance usually involves 1 or 2 years and for immediate use NRC should consider either a Code Case or some other appropriate NRC document to implement the recommendation.

6. Problems

There is no apparent problem with the proposed change in Item 3. However, the type of change discussed in Item 1 needs to be accompanied by a simple way to determine loads as discussed in Item 2.

Axial stress is not limited by Code Equation (9).

2.5.4 Consultant Suggestions for Research Programs

A program should be initiated with the specific objective of developing a simple way to establish loads from an elastic analysis of piping systems where the stresses in the piping exceed the present Code Equation (9) limits. This program should include, but not be limited to, a review of high-level test data and the Campbell [Ref. 2-21] and Broman [Ref. 2-22] reports.

The end product of this research should be the development of pseudolinear-elastic seismic analysis methods that conservatively and yet reasonably approximate the results of nonlinear time-history seismic analyses for piping systems. Design procedures that fully incorporate inelastic energy absorption and strain capability of piping systems should be developed. Two candidate techniques are the dynamic-to-static margin ratio technique of Reference 2-21 or the use of increased allowable stresses such as discussed in Reference 2-22. However, both techniques need further development and more comparison with nonlinear time-history analyses of realistic piping systems.

Upon review of Stevenson's report [Ref. 2-20], the details of straight pipe/excessive SAM should be examined. A program should be initiated with the specific objective of developing screening criteria to apply to this type of failure process.

2.5.5 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations regarding consideration of inelastic piping system response:

- o Change in Regulatory Position
 - Revise SRP Section 3.9.2 to state the goal of SSE performance criteria to be used in nonlinear piping analysis. Such performance criteria would establish a minimum margin against failure, where failure would be defined as (1) the onset of plastic tensile instability, (2) low-cycle fatigue or plastic ratchetting, (3) the onset of local or system buckling, (4) excessive deformation (resulting in more than a 15% reduction in cross-sectional flow area), or (5) functional failure of pipe-mounted equipment.
- o Research Programs
 - Develop pseudolinear-elastic estimation methods, and design procedures to account for inelastic response.

2.6 Strain Rate Effects

2.6.1 Consultant Views and Information

As illustrated by Figures 2-1 and 2-2, the strains of piping materials are a function of strain rate. The strain rates involved in the natural phenomena earthquake loadings can be estimated from the one-degree-of-freedom equation of motion:

$$y = y_0 \cos wt \quad (4)$$

where y = displacement (function of time) in inches

y_0 = initial displacement in inches

w = natural frequency in radians per second

t = time in seconds

The derivative with respect to time of Equation (4) gives

$$\dot{y} = y_0 w \sin wt \quad (5)$$

For structural modal responses that resemble the one-degree-of-freedom system, the strain contributed by a specific mode is proportional to the modal displacement y . Accordingly, Equation (5) can be expressed in terms of maximum strain rate as:

$$\dot{e}_{\max} = 2\pi e_0 f \quad (6)$$

where f is the modal natural frequency in cycles per second. Equation (6) gives values of $\dot{e}_{\max}$, for selected values of e_0 and f , as shown in Table 2-6.

Table 2-6

MAXIMUM STRAIN RATES FOR SELECTED VALUES OF MAXIMUM STRAIN
(e_0) AND FREQUENCY (f)

f, cps	$\dot{e}_{\max}$ (in/in/sec) for e_0 (in/in) of				
	0.001	0.0015	0.002	0.003	0.004
1	0.0063	0.0094	0.013	0.019	0.025
2	0.013	0.019	0.025	0.038	0.050
4	0.025	0.083	0.050	0.075	0.10
10	0.063	0.094	0.13	0.19	0.25
33	0.21	0.31	0.41	0.62	0.83

$$\dot{e}_{\max} = 2\pi e_0 f; \text{ see Equation (6).}$$

Figure 2-1. Effect of Strain Rate on Yield Stress, SA-106 Material

Figure 2-2. Effect of Strain Rate on Flow Strength, Type 304 Austenitic Stainless Steel

A standard tensile test is conducted at strain rates not greater than about 0.001 in/in/sec.; see, for example, ASTM A370 on Mechanical Testing of Steel Products. It can be seen in Table 2-6 that for combinations of low f and e_0 , the strain rates are about an order of magnitude higher than used in a standard tensile test to determine the yield strength of the material.

Values of $e_0 = 0.001$ and $e_0 = 0.002$, for a modulus of elasticity of 30×10^6 psi, correspond to stresses of $\pm 30,000$ and $\pm 60,000$ psi. The larger values of e_0 shown in Table 2-6 represent loads that produce plastic response. Because plastic response tends to occur at near the peak of the displacements where strain rates are less than at zero displacement, the values of $e_{0\max}$ shown in Table 2-6 for e_0 involving plastic response are upper bounds to the maximum plastic strain rates.

In summary, strain rate effects in earthquake loadings are small and do not merit inclusion in methods for determining piping system elastic-plastic responses to earthquake loadings.

However, at very high loading rates (e.g., water hammer), strain rate effects may be significant; see, for example, Reference 2-36. Also, very low loading rates (e.g., a hydrostatic test) may be significant in that failure can depend on whether the load is maintained for 5 minutes or 5 hours; see, for example, Reference 2-36.

2.6.2 Task Group Recommendations

The Task Group has reviewed the information above and recommends that no further action be taken to address seismic strain rate effects.

2.7 Single-Envelope Spectrum vs. Multiple-Independent Spectra

2.7.1 Consultant Suggestions and General Discussion

Seismic design of piping systems requires intermittent support devices in addition to terminal anchors. The support members are attached to numerous structural members that are located on various floors or sections of the same or even different buildings. Thus, piping systems will be subjected to multiple acceleration inputs during an earthquake event.

The solution for the response and safety of these complex piping systems is usually obtained by applying finite-element computer methods. The total response is usually expressed as the sum of the two components. One component, known as the dynamic or inertial component, is due to the inertia forces generated by the mass of the piping systems and the frequency of excitation of the inputs. The second component, on the other hand, has nothing to do with the piping mass. It is caused by the differential motion between the different support attachments. Since the motion of these attachments (often called the "seismic anchor motion") is a function of time, this latter component is also a function of time. However, it is termed the pseudostatic component.

The seismic forcing functions used for inputs to the piping system finite-element codes include time-history, uniform response spectrum, and multiple-response spectra representations. For complex systems, time-history analysis costs will

be excessively high. The final solution, however, obtained from solutions with independent support motion time-history input, includes the dynamic static and total response for each time point. Uniform and independent support motion response spectra computer runs, on the other hand, yield only the dynamic (or inertial) component of the response. In order to obtain the static components, a separate SAM analysis is required. While the requirement for calculating this component is specified, there is as yet no specified guidance as to how to perform this evaluation for either uniform or independent support motion response spectrum analysis.

Time-history analyses are costly to perform. Hence, the procedure most widely used in the nuclear industry to qualify piping systems is response spectrum analysis using as envelope spectra input from Regulatory Guide 1.60 for the dynamic responses (whose modal and directional combinations are performed per Regulatory Guide 1.92), and a separate SAM analysis for the pseudostatic components. The two components are then combined via the absolute sum method (see Item 9 of SRP Section 3.7.3).

As far as the multiple-support response spectra analysis method is concerned, there are no firm guidelines for a procedure to perform the SAMs and there are even some questions pertaining to the inertia component calculations. Each large architect/engineering (AE) firm developed its own method for calculating this particular response.

The problems or drawbacks to the method are twofold. For the dynamic analysis, there are questions pertaining to the methods for response combination between modes, directions, and support points or groups and the sequence of their combinations. Similarly, for the pseudostatic response, there is no agreed upon method. Instead, each large AE seems to be calculating this component by its own method. There is a need for a uniform approach that could yield optimum pseudostatic response. Similarly, there is a need for an optimum method for combining the dynamic and pseudostatic responses.

One of the main reasons for pursuing the multiple-response spectra method for response and safety evaluations of nuclear piping systems instead of the currently used uniform-envelope excitation method is the consensus that the multiple method could result in less conservatism for the designs and yet still provide the required margin of safety. The computer runs for the multiple-response spectra method are not much costlier than those for the response spectra method. Furthermore, since the multiple-response spectra assumption is closer to reality than the uniform-envelope excitation assumption, there are strong incentives for adopting this method for piping system analysis.

If a uniform less-conservative design that still provides adequate safety margins for piping systems results as a consequence of a better multiple-support analysis method, the impact to piping design is obvious. Fewer supports or snubbers may be required for the seismic design, thus reducing some of the reliability or malfunction problems and perhaps also some of the inspection radiation exposure problems.

2.7.2 Status of Ongoing Work

To assess the conservatism inherent in the current piping response spectrum analysis methods, the NRC funded a research program with the following aims: (1) to develop a combination method that can be used to predict the dynamic response of piping systems subjected to multiple-support excitations, (2) to formulate a uniform procedure to calculate the SAMs or pseudostatic response of the piping system, and (3) to identify an optimum combination procedure for the two responses, inertia and seismic anchor movement. The overall intention in developing each of the items was to reduce excessive conservatism in design while still maintaining a safe system.

Findings and recommendations of the Brookhaven National Laboratory (BNL) research program were published in August 1984 [Ref. 2-37]. Further work is planned at BNL to investigate the effect of floor-to-floor response phase correlation on the spectra combination methods recommended in Reference 2-37. BNL has also completed a brief assessment of the "center of mass" approach that is now being reviewed by the PVRC.

The NRC Piping Review Committee reviewed BNL's suggestions and modified them. The NRC recommendations on response combination methods to be used with the multiple-independent spectra method have been published in Section 2 of Volume 4 of NUREG-1061.

2.7.3 Consultant Suggestions for Research Programs

Research should be undertaken to evaluate other approaches that have been proposed to overcome the deficiencies inherent in the conventional uniform floor spectrum method. Two of these deserving further examination are the composite-system method and the cross-cross floor spectrum method. Details of both methods with some sample applications are given in Appendix E to this document.

2.7.4 Task Group Recommendations

The Task Group reviewed the above and makes the following recommendations regarding multiple independent spectra input:

- o Change in Regulatory Positions
 - Revise SRP Section 3.9.2 to permit and encourage the use of multiple-response spectra methods for more realistic seismic response analysis (for details, see Section 2 of Volume 4 of NUREG-1061).
- o Research Programs
 - Investigate phase correlation between floor responses, and recommend changes to spectra combination methods, as appropriate.

2.8 Suggestions for Rationalizing Overall Design Margins

2.8.1 Consultant Views and General Discussion

An optimal piping design criterion should be developed on a reliability basis. A key element to consider in developing a more rational design criterion is that a proper balance be maintained among margins associated with various effects. A piping design criterion cannot and should not be developed for any one particular loading alone. It has to be developed so that all the possible loading conditions are considered. The effects of various loading conditions may be different or even opposite. Rational overall design margins can be achieved only when the proper balance is maintained among the various loading conditions in the assessment of margins against realistic failures.

Extensive operating experience involving the thermal loadings of nuclear piping has given us confidence in the accuracy of methods used to predict thermal response and failure. However, earthquake experience for nuclear plants is extremely limited, and there is much uncertainty involved with the prediction of seismic response and failure. Nonnuclear experience [Ref. 2-20] gives us confidence that piping for other heavy industrial facilities has much inherent seismic capacity. But while the lack of actual failure data indicates high margins, it also prevents us from confidently quantifying failure levels and identifying the actual failure modes. Also, the extensive test data available are primarily for static loadings, and it is not entirely appropriate to directly apply these data in estimating time-dependent (and nonmonotonic) behavior. A better description of seismic failure levels and modes is needed in order to better quantify, and then balance, the margins in piping design. Additional capacity testing involving seismic-like loadings is needed.

Definition of Design Margin

We define design margin, DM, as:

$$DM = L_f / L_a \quad (7)$$

L_a = anticipated or postulated combination of loads.

L_f = combination of loads that would be expected to produce failure in the piping system assuming minimum material properties but no prior degradation (e.g., stress corrosion cracks).

The term failure includes:

1. Leakage of piping system pressure boundary.
2. Overloading of connected equipment (e.g., a valve or pump).
3. Excessive displacements (e.g., movement such that some part of the piping system would contact and damage adjacent equipment or such that the flow area through the piping would be significantly reduced).

The term design margin, as we have defined it, is equivalent to the more common term "factor of safety"; the change in terminology does not alter the problems.

Design Margin Development

Piping systems made of metal constitute a subset of metal structures. Metal structures have been in use for many centuries, but what might be called the modern technology of piping systems dates back about two centuries when steam was first used as a source of power. In the past roughly 60 years, the technology of the past two centuries has been standardized in the form of codes, design manuals, and specifications, etc. These standards reflect the accumulated experience (successful and unsuccessful) over many years. The standards are continuously revised to reflect the introduction of new techniques or improvement of existing techniques. (For example, one of the most significant changes in technology has been the introduction of electric-arc welding as a method of joining metals.) These standards reflect such aspects as the quality and quality-control of metal products, fabrication techniques and their control, inspection techniques (x-ray, ultrasonics), the accuracy with which loads can be predicted (a particular problem for earthquakes), and the capability of evaluating the response of piping systems to anticipated loads.

Table 2-7 lists the major considerations involved in establishing pressure vessel and piping design rules. While these rules do not define design margins (or factor of safety or factor of ignorance), the rules can be interpreted in terms of design margins as defined above.

Industrial codes have, for the most part, developed rules that are applicable to normal loadings. For piping systems, the loads consist of internal pressure, weight, and thermal expansion. In contrast, Section III, "Nuclear Power Plant Components," of the ASME Boiler and Pressure Vessel Code (hereinafter called the Code) introduced* the concept of normal, upset, emergency, and faulted conditions, now identified as Service Levels A, B, C, and D. In large part, service levels were introduced to provide what was deemed to be a rational approach for evaluating abnormal loadings such as earthquakes.

Code Service Levels

The Code provides design rules for four service levels identified as A, B, C, and D. The philosophy involved is indicated by the following quotes from Code NCA-2142.2:

Level B: "The component or support must withstand these loadings without damage requiring repair."

Level C: "The occurrence of stress to Level C Limits may necessitate the removal of the component (or support) from service for inspection or repair of damage to the component or support."

*In the 4th (1971) edition for Class 1 components; in the 6th (1977) edition for Classes 2 and 3 components.

Table 2-7

CONSIDERATIONS INVOLVED IN ESTABLISHING DESIGN MARGINS
FOR PIPING SYSTEMS

I. Construction, Other Than Design

1. Materials
2. Fabrication and examination
3. Inspection
4. Testing

II. Loading

1. Internal pressure
2. Weight
3. Thermal expansion
4. Thermal gradients
5. Dynamic
 - a. Vibration
 - b. Relief valve operation
 - c. Water hammer, steam hammer, slug flow, etc.
 - d. Wind
 - e. Earthquake

III. Accuracy of Available Methods and Data to Estimate Probability of Failure

IV. Degradation of Pressure Boundaries

1. Erosion
2. Corrosion
3. Hydrogen embrittlement
4. Caustic embrittlement
5. Intergranular stress corrosion cracking

V. Degradation of Supports or Restraints

1. Corrosion
2. Wear (e.g., of a constant load support)
3. Dirt or lack of lubrication (e.g., on a sliding support)
4. Lockup of snubbers due to corrosion
5. No restraint due to oil leak in hydraulic snubber

VI. Inservice Inspection

VII. Cost/Benefit Ratio

Level D: "These sets of limits permit gross general deformations with some consequent loss of dimensional stability and damage requiring repair, which may require removal of the component from service."

While not so stated, an obvious implication is that Level A rules are such that damage requiring repair does not occur. Further, "damage without repair" contains the implication that the anticipated number of Level A and Level B loadings will not cause a fatigue failure.

The Code does not say what loads or load combinations are to be placed in the four service levels. This choice is made by owners with concurrence of the NRC. Presumably, these choices are made with awareness of the concepts of NCA-2142.2 and, at least in a qualitative sense, the design margins associated with each service level.

2.8.2 Consultant Views on ASME Code Design Margins

The most obvious design margins can be deduced from the method of establishing allowable stresses in tension. Table 2-8 indicates the basis used for establishing the Code-allowable stresses. These are fractions of the minimum specified and minimum expected at elevated temperatures tensile yield strengths and ultimate strengths of the material. The selection of these fractions was developed over many years, with careful consideration of the many interacting items listed in Table 2-7. In particular, the fractions represent a consensus position on Item VII of Table 2-7, the cost/benefit ratio appropriate for nuclear power plant components.

The variation in design margin with service level is indicated by Code Tables NC-3321-1, NC-3416-1, and NC-3521-1. These tables, in conjunction with Table 2-8 lead to design margins as shown in Table 2-9.

A rather obvious cost/benefit evaluation is apparent by comparing the design margins on ultimate load with those in yield load. The writers of the Code recognized that the benefit obtained by preventing yielding is less than that obtained by preventing breaking.

Design rules in Code Subsection NF for piping supports lead to about the same design margins as shown in Table 2-9. One noteworthy exception occurs for linear-type supports. The basic allowable tensile stress is $0.6S_y$, leading to a design margin on yielding of 1.67. Table NF-3623(b)-1 gives stress limit factors of 1.0, 1.33, 1.5, and 2.0 for Levels A, B, C, and D, respectively. This leads to design margins on yielding of 1.67, 1.25, 1.11, and 0.833 for Levels A, B, C, and D, respectively. It may be noted that these design margins are a bit higher than shown in Table 2-9 under "Yield Load." In Level D, the design margin on yielding is less than unity, but an additional requirement is that the tensile stress must not exceed $0.7S_u$; hence, a design margin on ultimate load of 1.43 is maintained.

Design margins for tensile loads include the evaluation of membrane stresses due to internal pressure. We deem these design margins to be the most significant of all such margins embedded in Code rules. However, there are many other types of stresses and failure mechanisms that are covered by Code rules. The design margins and/or factors of safety associated with these rules are discussed in

Table 2-8

CODE FACTORS^(a) USED IN ESTABLISHING ALLOWABLE STRESSES IN
TENSION FOR PRESSURE BOUNDARY EVALUATION^(b)

Material	Class 1		Classes 2/3	
	$S_y^{(c)}$	S_u	$S_y^{(c)}$	S_u
Any, except bolting	2/3	1/3	2/3	1/4
Bolting ^(d)	1/3	---	2/3	1/4

- (a) Allowable stress = factor times the material property: S_y = tensile yield strength; or S_u = ultimate tensile strength. Where factors are shown under both S_y and S_u , the lower of the two criteria is used to establish the allowable stress.
- (b) This table is abstracted from Article III-3000 of the ASME Code and is specifically for ferrous materials.
- (c) For authentic stainless steels, the allowable stress may be up to 90% of the yield strength at temperature.
- (d) For Class 2/3 heat-treated bolting material, the allowable stresses do not exceed 1/5 of the specified minimum tensile strength or 1/4 of the specified minimum yield strength.

Table 2-9

DESIGN MARGINS^(a) FOR TENSILE LOADINGS OTHER THAN BOLTING

Level	Ultimate Load		Yield Load	
	Class 1	Class 2/3	$S = (2/3)S_y$	$S = 0.9S_y$
A	3.00	4	1.4	1.11
B	2.73	3.64	1.36	1.01
C	2.00 ^(b)	2.67	1.00	0.74 ^(b)
D	1.50 ^(c)	2.00	0.75	0.56

- (a) Based on values of σ_m shown in ASME Code Table NC-3321-1.
- (b) NB-3224 limits lead to a design margin of 2.5 on ultimate load, 1.00 on yield load.
- (c) Appendix F, F-1331.1, limit of $0.7S_u$ leads to a design margin of $1/0.7 = 1.43$ on ultimate load.

References 2-38 and 2-39 with respect to Code fatigue evaluation methods. Accordingly, below we will very briefly indicate bounds in design margins associated with Code rules.

Cyclic Loads and Fatigue

For Class 1 components, the design margin is 2 on stress or 20 on cycles, whichever is more restrictive. The Code does not require fatigue evaluation for Class 2 or 3 components. However, for Class 2/3 piping, the design rules have an embedded fatigue-based concept. Reference 2-39 brings out the point that, for cyclic moments, the design margin is conceptually 2 on stress. However, in detail, this design margin could range from 10 (low number of moment cycles) to less than unity for a high number of thermal gradient cycles.

Buckling

This type of failure is covered in considerable detail by design rules in Code Subsection NF, "Component Supports." For the simple case of column buckling, the design margins are about 1.7 on yielding for columns with low "slenderness" to about 1.9 for columns with high "slenderness." These are Level A design margins; for Level D, the design margin of columns that fail by elastic instability is 1.5. Buckling on the compressive side of beams in bending may occur. The design margins for this type of buckling are not readily discernible from the Code rules. (The previous discussion refers to "linear type" piping supports. Plate and shell supports could also be used and would have different margins.)

Combined Membrane and Bending Stresses

Provided no buckling occurs, the intended Code margins are indicated by Figure 2-3, taken from Reference 2-40. If the allowable stress is $(2/3) S_y$, Level A loads will not exceed the limit load. However, Level D loads may exceed the limit load and the design margin, with respect to limit loading, will be less than unity. Exceeding the limit load does not necessarily mean that gross plastic deformations will occur; in structures, a collapse mechanism must be present.

NB/NC/ND-3600 Equation (9)

Code Equation (9) is analogous to Code limits on combined membrane-plus-bending stresses in that it is based on limit load concepts. The background of Code Equation (9) is discussed in Reference 2-34.

On the basis of an elementary, single-hinge, limit moment evaluation, it can be shown that the design margin provided by Equation (9) can be as low* as $2/\pi = 0.64$ for Level D. However, the general perception of Code Equation (9) is that it is too restrictive when applied to evaluation of earthquake loadings. Recently available test data in which simulated earthquake inputs were applied to simple piping systems are discussed later.

*Based on $2S_y$ limit. The $3S_m$ limit of Code Appendix F for $S_m = 0.9S_y$ leads to a design margin of 0.47 on limit moment.

Figure 2-3. Limit Stress for Combined Membrane and Bending, Rectangular Section, from Reference 2-40

2.8.3 Consultant Views on Industrial Code Design Margins

After 20 years of development of various forerunner guides for design of piping systems, in 1935 the first edition of the "American Tentative Standard Code for Pressure Piping" (B31.1) was published. This B31.1-1935 contained the following sections:

1. Power piping systems
2. Gas and air piping
3. Oil piping systems
4. District heating piping systems
5. Refrigeration piping systems.

Section 1 is the predecessor of ANSI B31.1, "Power Piping," a code of some interest because, in early nuclear power plants, piping systems were designed to it. Up to 1942, the allowable stresses for power piping were based on 1/5 of ultimate; hence, the design margin on breaking was 5 rather than the present 4.

Section 2 is the predecessor of ANSI B31.8, "Gas Transmission and Distribution Piping Systems." Section 2 in 1942 and B31.8 at present base allowable stresses for internal pressure (where the piping is located in sparsely populated areas) on $0.72 S_u$. There is no specific margin on ultimate strength but, for materials typically used in gas transmission lines ($S_u/S_y \geq \sim 1.4$), this translates to a design margin on breaking of about 1.9.

The significant difference in design margins of 5 (now 4) for power piping, 1.9 for gas transmission piping, is relevant to cost/benefit perceptions. While there are a number of cogent considerations listed in Items I thru VI of Table 2-7 that would support lower design margins for gas transmission piping, Item VII is the key consideration.

1. Gas transmission piping systems typically consist of hundreds of miles of large (e.g., 30") diameter pipe. The reduced cost (of the pipe itself plus handling and welding) obtained by using a design margin of 1.9 rather than 4.0 must have been (and is) blatantly obvious to owners of gas transmission piping.
2. The cost of inservice failures in buried pipe in sparsely populated areas was apparently perceived to be sufficiently low that benefits obtained by using a higher than 1.9 design margin were not sufficient to compensate for the increased costs.

Experience with gas transmission piping over the past 40 years has confirmed the appropriateness of the cost/benefit evaluation. However, our main points here are:

1. Cost/benefit evaluation provides a rational basis for evaluation of Code rules and design margins embedded therein.
2. Cost/benefit ratios can vary between industries and, in the nuclear power plant industry, the benefits obtained by reducing the probability of inservice failures may be orders of magnitude greater than in other industries.

Industrial piping codes have only recently provided guidance for abnormal loadings. Early editions mentioned wind and snow or ice loads but did not specifically allow higher stresses for such loads. Earthquake (or seismic) was not mentioned. However, by the 1973 edition, specific guidance is given.

Either pressure or temperature, or both, may exceed the design values by

15% for 10% of time

20% for 1% of time

For pipe support elements, an increase in stress of 20% was permitted for "short time overloading conditions during operation." However, the question of allowable stresses for combinations of pressure and moment loadings was not specifically addressed until the Summer 1973 Addenda to ANSI B31.1 in which

$$PD_o/4t + 0.75i (M_A + M_B)/Z \leq kS_h$$

where

P = internal pressure

D_o = pipe outside diameter

t = pipe wall thickness

i = stress intensification factor

M_A = resultant moment due to sustained loads, e.g., weight

M_B = resultant moment due to occasional loads, e.g., earthquake

Z = pipe section modulus

S_h = allowable stress at operating temperature

k = 1.0 (and M_B = 0) for sustained loads

k = 1.15 for occasional loads acting less than 10% of time

k = 1.20 for occasional loads acting less than 1% of time

Since earthquake loads certainly are acting less than 1% of the time, the increased stress allowance for stresses for combined loadings, including earthquakes, is a factor of 1.2. This factor is consistent with an earthquake placed in Level B, but is more restrictive for an earthquake placed in Level D.

The AISC "Manual of Steel Construction" is also pertinent to nuclear power plant design because, until recently, many piping system supports were designed using the AISC manual. Paragraph 1.5.6 of the AISC specification for the design, fabrication, and erection of structural steel for buildings (included in the AISC manual) states, in effect, that allowable stresses may be increased by one-third in evaluating calculated stresses produced by earthquake loadings combined with normal loadings. This factor of 1.33 is the same as used in Code Subsection NF for Service Level B.

Comparison to Nuclear Power Plant Piping

We noted above that cost/benefit evaluation for power piping and gas transmission piping led to significantly different design margins. Nuclear power plant piping involves cost/benefit ratios quite different from those in any other industries. In particular, the benefit to be obtained by reducing the probability of inservice failures is perceived to be very large. The TMI accident illustrates that an inservice failure that would have relatively trivial cost consequences in a fossil power plant had cost consequences measured in billions of dollars in a nuclear power plant.

The perception of very large costs of inservice failures in nuclear power plants has led to very stringent requirements for control of materials, fabrication, inspection, testing, and inservice inspection. Furthermore, in an attempt to limit the potential consequences of inservice failures, the NRC requires that breaks be postulated at many locations in piping systems. The piping systems must be restrained or isolated so that the consequences of these postulated failures can be deemed to be acceptable.

However, from the viewpoint of design margins for normal operating conditions, the NRC criteria (having adopted the ASME Code as a design guide) are no more stringent than those for industrial piping. For the important and relatively well-quantified pressure loading case, the design margin for Code Class 1 piping is less than for ANSI B31.1 piping. Further, for abnormal loadings (e.g., earthquakes in Level D), the NRC accepts lower design margins than are acceptable under ANSI B31.1. Presumably, an underlying design assumption is that the more rigorous analysis for earthquakes required by the NRC justifies the lower design margins.

Design margins for Code Service Levels A and B are consistent with industrial codes and the implicit cost/benefit evaluations therein. For Service Level D, the Code design margins are smaller than any traceable to industry codes. However, the low-probability loads used with Level D (SSE, large-pipe breaks) provide a rational basis for the seemingly low design margins for Service Level D. Furthermore, the design margins are consistent with the Code philosophy of service levels. We deem the presently used Code design margins to be rational and do not recommend any changes.

2.8.4 Consultant Views and Suggestions on Earthquake Problem

While Code design margins are rational, this does not help to mitigate an "earthquake problem" described briefly below. Earthquake design used for nuclear power plant piping systems has led to large costs with perhaps negative benefits. This widely held perception led to the creation and activities of the PVRC Committee on Piping Systems and the NRC Piping Review Committee.

The process of evaluation of the ability of piping systems to withstand earthquakes can be considered as consisting of three steps:

1. Magnitude of Earthquake at Site

Seismic hazard curves in which the "probability of exceedance per year" is plotted against "peak ground acceleration" have been developed. Seismic risk studies use these curves as input and their results typically indicate that the uncertainty associated with seismic

hazard dominates the total uncertainty in predicting earthquake-induced piping failure. Progress in reducing the site seismic hazard uncertainty will be slow at best.

2. Translation of Site Earthquake to Piping System Input

A time-history calculation that involves soil properties, soil-structure interaction, and the characteristics of the building containing the piping system leads to the development of response spectra for various floors or elevations in each building.

3. Evaluation of Piping System Input

Typically 100 to 200 piping systems are required to be evaluated in a nuclear power plant. The floor response spectra are used to estimate the moments and forces acting on the piping pressure boundaries, supports, and restraints. These moments and forces are combined with those resulting from other loads such as weight and thermal expansion. Supports and restraints are selected from manufacturers' catalogs (where the rated loads are given) or are designed with design margins as previously discussed. Loads on equipment nozzles are checked against allowable loads furnished by equipment manufacturers and vessel designers. Stresses in the piping, including those due to internal pressure, are checked against Code criteria. This is often an interactive process in which earthquake restraints are added as required to meet both equipment nozzle load and pressure boundary criteria. Placement of restraints is often dictated by the locations of building structures that can take the calculated loads. Thus, along with time and budget restraints, the piping system design is seldom optimized. Snubbers are often used where a rigid restraint would be more appropriate.

Each of these three steps involves large uncertainties. The general tendency has been to overestimate loadings in each step.

A highly undesirable aspect of earthquake design of nuclear power plant piping systems is that the piping designer is forced to spend almost all of his available time on this aspect. The more important aspect of pressure design is almost ignored. Optimization of the overall design from the standpoint of weight and thermal expansion is severely restricted by the use of earthquake restraints. In many cases, earthquake restraints are secured by lugs welded on the pressure boundary. During normal operation, these welded-on lugs significantly increase the possibility of a pressure boundary failure. If an earthquake does occur, the restraint forces acting through the lugs might rupture the pressure boundary; whereas, without the restraint, the piping would not be damaged.

In summary, the three-step analytical approach appears to have led to large costs with perhaps negative benefits. The following sections discuss some approaches that may mitigate the earthquake problem.

Approaches to Mitigate Earthquake Problem

1. Experiences with Piping Systems During Earthquakes

References 2-20, 2-41, and 2-42 indicate the type of insight to be gleaned from reviewing experiences during earthquakes. The observations made suggest that few, if any, earthquake restraints are needed on piping systems. If this is true, the cost of the many thousands of earthquake restraints being installed on piping systems in nuclear power plants may be a waste of many millions of dollars.

Presumably, there is a much larger amount of such experiences than are described in published documents. The NRC has provided limited funding for a program to accumulate, review, and evaluate such experiences with respect to the design of nuclear power plants. The benefits of this work are substantial but the time and budget limitations may be insufficient. We suggest that NRC place a high priority on future work of this type. The NRC response that led to References 2-20 and 2-42 is commendable and will aid preparation to similarly respond to future major earthquakes or past earthquakes where relevant unpublished data may exist.

2. Earthquake Simulation Tests

EPRI and NRC have sponsored tests at ANCO Engineers, Inc., of simple piping systems consisting of (1) a Z-bend, (2) a three-dimensional piping system with two anchors, and (3) a three-dimensional piping system with two branches and four anchors. The tests consist of driving the supports with hydraulic cylinders programmed to input simulated earthquake motions.

References 2-43 and 2-44 indicate that these piping models had margins in excess of three or four times the SSE load limits. These results suggest that the Code limits contain very large margins and that the earthquake problem could be mitigated by using less restrictive Code limits.

EPRI is currently planning a major program to demonstrate piping failure limits and failure modes under dynamic loadings. The NRC should endorse and participate in this program.

3. Insignificant Earthquakes

Kennedy [Ref. 2-29] states: "... the OBE piping analysis should only be required in those cases where it clearly would add to safety or reliability. There is substantial empirical evidence to justify that thickwalled, butt-welded ductile steel piping is inherently rugged so as to withstand at least moderate seismic events without failure even if the piping has not been seismically designed. Furthermore, nuclear plant piping is being designed for at least the SSE. Therefore, in my opinion, if the OBE is less than or equal to about 0.07g and less than or equal to 1/2 SSE, then an OBE design of piping does nothing to add to safety and should not be required. It represents analytical effort for no purpose. Even nonseismically designed piping systems have been demonstrated to withstand ground motion substantially greater than 0.07g."

This concept might be extended to include other materials than just "ductile steel" and other connections than just "butt-welded." There are some flanged joints in Class 1 piping at pressure relief valves and quite a few in Class 2

or 3 piping systems. However, suitable restrictions would be needed to exclude the application of this suggestion to piping systems with "weak" joints. Possibly buried pipe should be excluded. More broadly, if it is deemed reasonable (on the basis of a cost/benefit evaluation) to use 0.07g as an SSE for some particular site, earthquake evaluation of piping systems may not be required for that site. (See Chapter 3 of this report.)

4. Reliability Analysis

We view cost/benefit evaluation as the basic criterion. Reliability analysis provides a valuable input to a cost/benefit evaluation. There are, of course, large uncertainties in both earthquake loadings and the capacity of piping systems to withstand earthquake loadings in combination with other loadings. However, the systematic study of those uncertainties by a reliability analysis provides guidance on the probability of avoiding inservice failures as a function of design procedures.

Reliability analysis of piping systems in which earthquake restraints are secured by lugs welded on the pressure boundary should include the probability and associated uncertainty of pressure boundary failure during normal operation and the possibility of pressure boundary failure during an earthquake when the restraint forces act through the lugs.

2.8.5 Consultant Views on Functional Capability of Piping

The function of nuclear power plant piping is to convey fluids from one location to another. Sizing of the pipe usually involves a compromise between the increasing installed costs with increasing size and the decreasing pressure drop as size increases. The Code does not address the functional capability of piping systems; it is concerned with pressure boundary integrity of the piping systems. Accordingly, it does not necessarily follow that meeting Code rules will ensure functional capability.

Reference 2-34 discusses the available data on the plastic response of piping systems. This report made a number of recommendations, some of which were adopted by the Code. Reference 2-34 states that Level D limits should not be used for piping systems that must remain functional during the postulated events.

Since 1978 when Reference 2-34 was written, a significant amount of additional data of the effects of earthquakes on piping systems have become available, some of which is discussed in Section 2.5. The data indicate that concern about functional capability of piping systems is not warranted provided the major calculated loads are earthquake induced and not, for example, weight or steady-state relief-valve-induced loads.

In view of the recent data, it is recommended that the NRC staff in SER reviews provide some relaxation of their present position. The present position, in its broadest terms, can be described as acceptance of demonstration of adequate functional capability by meeting Level C limits for all events, including SSE. It is recommended that NRC use the functional capability criteria:

Meet 1983 Code Equation (9) Level C or, if the applicant can show that at least one-half of the stress in 1983 Code Equation (9) for SSE comes from the SSE inertia moments, meeting 1983 Code Equation (9) Level D limits is acceptable.

This recommendation is obviously arbitrary but, in view of recent data, is deemed to be defensible.

At present, concern about functional capability is being focused on stainless steel elbows. With the recommendation in Section 2.5.3, carbon steel elbows will have the same criteria (yield strength) as stainless steel. The above recommendation is deemed appropriate. It should be noted that the Code itself limits use of B indices to $D_o/t \leq 50$; hence, piping with larger D_o/t will remain a special case.

2.8.6 Consultant Suggestions for Research Programs

1. Experiences with Piping Systems During Earthquakes

A continuing program should be established to accumulate data, evaluate that data, and issue periodic reports. It is suggested that NRC place a higher priority on this type of work than they have in the past.

2. Insignificant Earthquakes

A program should be initiated with the specific objective of determining a level of earthquake (e.g., 0.07g) that would be insignificant with respect to piping systems and their supports. At many sites, this might mean that OBEs (and possibly SSEs) would not require evaluation.

3. Earthquake Simulation Tests

The NRC should support test programs (e.g., EPRI's piping capacity tests) for verifying piping seismic design margins and identifying failure modes. Test results should be evaluated and recommendations for criteria changes should be provided, as appropriate.

4. Reliability Analysis

Continued priority should be given to reliability analysis, including effects of lugs and trunions on pressure boundaries.

2.8.7 Task Group Recommendations

The Task Group has reviewed the above and makes the following suggestions for rationalizing overall design margins:

o Action Items

- Monitor and assess PVRC piping activities and ASME Code revisions, as appropriate.

- Assess piping experience when a seismic event occurs.

- o Research Programs

- Test programs (e.g., EPRI's piping capacity tests) for verifying piping seismic design margins and identifying failure modes should be supported. Evaluate test results and provide recommendations for criteria changes (e.g., reclassification of seismic inertial stresses as "secondary"), as appropriate.
- Encourage the nuclear industry to establish and justify an earthquake level that piping systems can sustain with sufficient confidence that no seismic analysis is needed.

- o Functionality Criteria

The suggestions above regarding changes to the functionality criteria were reviewed at the Piping Review Committee level. The following was recommended:

- The functionality criterion for piping will be maintained. Current ASME Code Class 1 or Class 2 stress evaluation procedures, not to exceed Level C limits, will be used. These limits are similar to those now being used on a case-by-case basis to satisfy the functionality criterion. It is recommended that the upcoming EPRI/NRC pipe tests be evaluated to confirm this position and to determine whether it is appropriate to use the current higher Level D stress limits.

3. ROLE OF OPERATING BASIS EARTHQUAKE VS. SAFE SHUTDOWN EARTHQUAKE GROUND MOTION

3.1 Consultant Views and Information

Reference 3-1 discusses historical development of the concept of a dual earthquake (OBE and SSE) design criterion. The dual earthquake concept has been applied to many critical industrial facilities (offshore platforms, pipeline projects, and hazardous industrial projects) in high seismic regions as well as to nuclear power plants.

The original concept was to design the project to approximately conventional code stress levels for an earthquake input that has a reasonable probability of occurrence in the design life of the project and then to "safety-check," using more liberal criteria, some critical aspects of the project for a larger earthquake input. Early nuclear power plant design followed this concept. The emphasis was on the smaller "design" earthquake for lack of a more refined definition. Liberal nonlinear strain checks were used for this double-design earthquake. By this concept, the smaller earthquake generally governed design except for a few critical components. Many nonnuclear industrial projects in high-seismic zones still follow this original concept.

In the nuclear industry, the design emphasis gradually gravitated toward the larger earthquake, which became the safe shutdown earthquake (SSE). More stringent criteria were established for checking the plant for the SSE. The SSE was directly determined as that earthquake that is based on an evaluation of the maximum earthquake potential considering the regional and local geology and seismology characteristics of subsurface material. The lesser earthquake that has a reasonable probability of occurrence during the design life became known as the operating basis earthquake (OBE). At this stage, each earthquake had its own seismological definition.

However, the original concept that the large earthquake (SSE) should be about double the lesser earthquake (OBE) was retained as a carryover from the past. Whereas in the past the lesser earthquake (OBE) was determined and then arbitrarily doubled to obtain the larger earthquake (SSE), now the SSE is determined and arbitrarily cut in half to obtain the OBE. In the process of coupling the OBE to the SSE, the concept that the OBE should have a reasonable probability of occurrence during the design life was lost. Certainly, the OBE should be more easily determined from historical seismicity than is the SSE. Thus, defining the better known earthquake as a constant factor of the lesser known earthquake seems nonsensical. The original intent of this two-to-one ratio was just the opposite.

The problem is that this coupling between the OBE and the SSE became institutionalized with the publication of Appendix A to 10 CFR Part 100 in 1971. Appendix A provides three definitions for the OBE:

1. The Operating Basis Earthquake is that earthquake which, considering the regional and local geology and seismology and specific characteristics of local subsurface material, could reasonably be expected to affect the plant site during the operating life of the plant; it is that earthquake which produces the vibratory motion for which those features of the nuclear power plant necessary for continued operation without undue risk to the health and safety of the public are designed to remain functional.
2. The Operating Basis Earthquake shall be specified by the applicant after considering the seismology and geology of the region surrounding the site. If vibratory ground motion exceeding that of the Operating Basis Earthquake occurs, shutdown of the nuclear power plant will be required. Prior to resuming operations, the licensee will be required to demonstrate to the Commission that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public.
3. The maximum vibratory ground acceleration of the Operating Basis Earthquake shall be at least one-half the maximum vibratory ground acceleration of the Safe Shutdown Earthquake.

Because of the third definition, the OBE is governing the design of most piping systems irrespective of the plant location or frequency of earthquakes. There is nothing inherently wrong with the fact that the OBE governs design in a region of frequent seismic activity, but the OBE should generally not govern design in a region of infrequent seismic activity. The problem with the OBE's dominating design for regions of infrequent seismic activity is that closer support spacing is necessary to meet OBE stress levels. This closer support spacing and the resultant stiffer piping is detrimental to thermal stresses. Excessive conservatism for the OBE can thus reduce the overall reliability of the piping system.

Purpose of OBE

The purpose of the OBE is to provide very high confidence of high functional reliability and a lack of damage needing to be repaired for continued operation after an earthquake that can be reasonably expected to occur during the plant design life. This high confidence is achieved by holding computed responses to normal code stress levels, using well-understood linear-elastic analysis procedures and conservatively specified analysis parameters where necessary.

A second purpose is to have a realistic earthquake level for checking low-cycle fatigue damage for those components that might be susceptible to fatigue damage under a combination of earthquake and thermal stress cycles.

These purposes justify the retention of the OBE for high seismic regions particularly when recommending the liberalization of the SSE design criteria for piping. For piping design, there appears to be only one reason why the OBE should be specified as being at least one-half the SSE. This is that seismic anchor movement (SAM)-induced stresses are considered secondary stresses and may be ignored at Service Level D. Thus, SAM stresses are ignored for the SSE but are considered for the OBE at Service Level B. This problem could easily be corrected by requiring that the larger of $1/2$ SSE or OBE be used in the secondary stress computations (Eq. 10 of the ASME code) at Service Level B.

If this potential deficiency were eliminated, there appears to be no purpose for tying the OBE to 1/2 SSE.

Impact of OBE on Design of Piping Systems

The OBE has two major impacts on the design of piping systems. First, the inclusion of an OBE significantly increases the analytical effort because OBE building structure and piping damping values differ from those for the SSE. Second, when the OBE is set at one-half the SSE, in the absence of LOCA or pipe-break loads, the OBE at Service Level B always controls the design of the piping system over the SSE at Service Level D.

The increased analytical effort is worthwhile if this additional effort actually leads to increased safety. Otherwise, it is analysis for analysis sake. Every effort should be made to reduce unnecessary analysis and concentrate analytical effort on improving the quality of necessary analyses. The first step in this direction is to use common parameters for the OBE and SSE analyses whenever possible. SSE damping should be used for both analyses. Thus, OBE results could be simply scaled from the SSE results rather than requiring a new analysis.

Second, the OBE piping analysis should be required only in those cases where it clearly would add to safety or reliability. There is substantial empirical evidence to justify that thickwalled, butt-welded ductile steel piping is inherently rugged so as to withstand at least moderate seismic events without failure even if the piping has not been seismically designed. Nonseismically designed piping systems have been demonstrated to withstand ground motion substantially greater than 0.07g. Furthermore, nuclear plant piping is being designed for at least the SSE. Therefore, if the OBE is less than or equal to about 0.07g and less than or equal to 1/2 SSE, a separate OBE design of piping represents analytical effort with little benefit.

3.2 Consultant Suggestions for Regulatory Changes

Decouple OBE from SSE

The nuclear safety concerns associated with the OBE in general have not been clearly identified in the Federal regulation. For instance, from definition (1) in the Federal regulation, it is clear that features necessary for continued operation (in the event of an earthquake up to the selected OBE level) must be designed to remain functional. However, there is no nuclear safety requirement that the plant continue to operate at or beyond the OBE or any other earthquake level. Presumably, if the plant were designed to be shut down for inspection and safety evaluation in the event of an earthquake beyond a selected level, there should be no safety requirement to design for continued operation above that level, although the design must be made to ensure containment and safe shutdown.

The owner/operator should have the option of selecting an OBE seismic design level considered necessary to protect his financial investment as indicated in definition (2) of the Federal regulation. The design requirement to safely shut down the plant up to the SSE level would seem sufficient to ensure nuclear safety. The additional requirement for seismic design at the 0.5 SSE level has

been established to provide high confidence of plant reliability at an earthquake level that could reasonably be expected to affect the plant site during the operating life of the plant. However, this goal could be better achieved by tying the OBE level to a specific recurrence interval rather than to 0.5 SSE. For instance, a 10% to 20% probability of occurrence in a 40-year design life would be consistent with recurrence intervals of 380 to 180 years, respectively. Thus, specifying a 200- to 400-year recurrence interval earthquake would be substantially less than 0.5 SSE. It is expected that for low seismic regions this definition would result in OBE levels of about 0.25 to 0.3 times the SSE.

Thus, the definition of the OBE in terms of a realistic recurrence interval would eliminate the problem that the OBE controls design in low seismic regions where it is unreasonable that it should control.

As a second part of this recommendation, for those sites where the OBE, by the above definition, is less than about 0.07g effective ground acceleration, the requirements for an OBE design could be eliminated on the basis that such a low earthquake level is not capable of damaging engineered heavy industrial facilities and power plants, particularly since the safety features of the nuclear plant would continue to be designed for a much larger SSE. Thus, keeping in mind that the safety systems are designed for a much larger SSE, the cost and effort associated with evaluating the plant for such a low earthquake should be considered as an unwarranted engineering effort. In general, the provision of not having to evaluate plants for an OBE of less than 0.07g coupled with the 200- to 400-year recurrence interval would eliminate the need for an OBE design in low seismic regions (that is, in general, regions where the SSE is equal to or less than about 0.2g).

When an OBE evaluation is not performed, the plant should be required to shut down for inspection if subjected to an earthquake greater than 0.07g or 1/2 SSE, whichever is less. If the utility judges these values to be too low, the utility has the option of establishing an OBE.

Avoid Dual Earthquake Analyses

The need to perform dual dynamic analyses for the OBE and SSE is unnecessary "gilding of the lily." Such dual analyses come about because different damping values are specified for the OBE than for the SSE. Money and time spent on these dual analyses could be better spent on performing parameter variation analyses for the SSE level.

We recommend that the same damping values be used for the SSE and OBE analyses of both civil structures (for generation of floor spectra) and piping and equipment supported on such structures. If this were done, OBE responses could simply be obtained by scaling the SSE responses by the ratio of OBE/SSE. The great improvement in efficiency would easily warrant the slight loss in accuracy.

[Editorial Note: The following paragraph was written before the new damping values were endorsed and therefore does not reflect this change.]

The SSE damping values in Regulatory Guide 1.61 plus the recommended revised damping values for piping are sufficiently conservative that they could be used

for both the SSE and OBE analyses so long as the SSE response of the civil structure upon which floor spectra are being generated is generally at least 50% of yield (steel) or ultimate (concrete). In cases where the SSE response is very low, lesser damping values should be used for the civil structure when floor spectra are generated. Admittedly, the use of SSE damping values for the OBE might lead to some underestimation of response at the OBE level. However, this underestimation is expected to be minor because of the conservative nature of the SSE damping values. Certainly there is far more than enough margin of safety in OBE acceptable stress levels to compensate for any such underestimation in response.

Secondary Stress

If the OBE is not required to be at least 1/2 SSE, problems develop because the ASME Code does not require consideration of secondary stresses at Service Level D (SSE). A solution to this problem is discussed in Section 2.5. The OBE should not be decoupled from 1/2 SSE unless secondary stresses from SSE SAM are considered by some alternative means.

3.3 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations regarding design for the OBE and the SSE:

o Action Items

- Initiate an NRC internal review to investigate the feasibility of using uniform structural and piping damping values for evaluating both the OBE and SSE and thus permit scaling of a single earthquake analysis.
- Request ASME to consider effects of seismic anchor movement at Service Level D (rather than at Level B) when the OBE becomes decoupled from the SSE.

o Change in Regulatory Positions

- Recommend that rulemaking be undertaken that would change the OBE definition in Appendix A to 10 CFR Part 100 to permit decoupling of the OBE and SSE. (The Atomic Safety and Licensing Appeal Board's June 16, 1981 decision on Diablo Canyon (Ref. 3-2) clarifies that the OBE does not have to be directly coupled to the SSE value.)

4. DESIGN PRACTICE FOR MORE RELIABLE PIPING SYSTEMS

This chapter deals with design practice for more reliable piping systems. Basic problems in current industry practice are reviewed in Section 4.1. Section 4.2 deals directly with limiting the use of snubbers, which have been shown to malfunction in some cases. Section 4.3 discusses how the current design practice and responsibility lead to overdesign in terms of supports and snubbers. In Section 4.4, recommendations for optimizing support designs are given.

4.1 Basic Problems in Current Industry Practice

Over the last two decades, the industry practice for nuclear piping system design has undergone dramatic change. The major reasons for this are the changes brought about by NRC regulatory requirements and the extensions and revisions to the ASME Code criteria. These changes have resulted in a design process that is predominantly analytical and is dependent on many nonpiping design considerations.

The basic problem with current industry design practice is excessive use of complex analysis methods to satisfy regulatory procedures and Code compliance. Many times the design process results in piping designs that are not optimized, especially with regard to snubber and other supports. Perhaps this is a weakness with the Code itself since it does not provide guidance regarding design details that, based on past experience, are known to be more appropriate for certain geometry or loading conditions.

The topics discussed in the sections that follow address the major issues pertaining to this problem. In addition, many suggestions to improve current industry practice for piping design are detailed in the position paper by the PVRC Technical Committee on Piping Systems entitled "Technical Position on Industry Practice" [Ref. 4-1].

4.2 Use of Snubbers for Piping Systems in Nuclear Power Plants

4.2.1 Consultant Views and General Discussion

Development of Use of Snubbers

Nuclear power plants designed prior to 1966 were based primarily on conventional power plant experience and used few or no snubbers on piping systems. Seismic-induced inertia loads and stresses in piping systems were low given the manner in which earthquake loads were defined in piping at that time. Hence, snubbers were generally not needed. Starting about 1966, the procedures used for the computation of seismic loads and stress resultants in the piping underwent significant change. Use of the floor or amplified response spectral curves and a desire to limit pipe response to the relatively high frequency range above regions of resonance response of buildings (typically >10 Hz) tended to promote the increased use of snubbers. Typical applications increased from fewer than 100 snubbers per plant designed prior to 1969 to more than 300 snubbers in the 1969 to 1972 period [Ref. 4-2].

In 1973 the implementation of the Regulatory Guide 1.60 ground response spectra and the associated three component floor spectra resulted in a significant increase in calculated seismic stresses in piping systems. The period after 1973, which included implementation of Appendix B to 10 CFR Part 50 quality assurance requirements, was also characterized by extremely rapid growth in the design documentation and control requirements and the seismic analytical and administrative complexity necessary to document the design adequacy of piping systems. Experienced personnel were stretched thin, and the liberal use of snubbers was relied upon by relatively inexperienced piping designers and analysts as a design expedient to demonstrate adequacy for high-temperature piping systems subjected to significant thermal movements and relatively high seismic loads.

Today plants are nearing completion that were designed between 1973 to 1978. They typically have in excess of 1,500 snubbers. There are examples of single nuclear power plant units with more than 3,000 snubbers.

Historically the use of snubbers has tended to shift from hydraulic to mechanical type snubbers. Hydraulic snubbers were the first to reach the nuclear power plant market in large quantities in the late 1960s and early 1970s. Mechanical snubbers have tended to dominate snubber procurement since about 1977.

Numerous operating problems with the hydraulic snubbers consisted principally of leaking seals and a loss of hydraulic fluid resulting in a loss of restraint capability [Ref. 4-3]. This situation resulted in an NRC-mandated inservice inspection and maintenance program for hydraulic snubbers starting in 1973 and tended to promote the use of mechanical snubbers that were not susceptible to the loss of hydraulic fluid. A similar NRC-mandated surveillance program due to corrosive lockup of mechanical snubbers was begun in 1981 [Ref. 4-4].

There have been over 500 separate reported instances (Licensee Event Reports, LERs) of snubber malfunction or operation out of Technical Specification limitations in nuclear power plants. These events are summarized in Appendix F to this report with a histogram of snubber incidents. In Table F-1 is a summary of the estimated total snubber population. This estimate is based on incomplete data contained in References 4-2, 4-5, 4-6, and 4-7 and should not be considered a definitive estimate of snubber usage. However, it is probably the best snubber population estimate available short of requesting all operating nuclear plants and those nearing completion to provide a current snubber inventory. It should also be noted that not all snubber failure events are reported in the LERs.

References 4-8 through 4-12 document recent snubber-related problems.

Regulatory Criteria

Regulatory criteria specific to snubbers are found in Sections 3.9.2 and 3.9.3 of the standard review plan (NUREG-0800).

In addition to these regulatory criteria, a draft regulatory guide on snubber qualification and acceptance testing (Draft Regulatory Guide SC 708-4) has been developed, and detailed IE inspection program procedures are currently

being developed that should be evaluated as to their effect on snubber requirements. Although the draft regulatory guide has been referenced and endorsed by some industry and government organizations (Refs. 4-3 and 4-13), it has not completed the internal NRC approval process needed to make it an active NRC standard.

Problem Areas and Their Causes

The problem area concerning snubbers of probably the most concern to the nuclear power industry is the very high cost of current snubber inservice inspection and maintenance programs. Such programs typically range from \$200,000 to \$1,000,000 per year per plant in direct costs. These programs also entail significant radiological exposure to plant personnel.

Snubber operating characteristics and limits were generally established at time of purchase. These limits were set by the purchasers to obtain the widest range of useful operation. For example, the purchaser might specify a 30 inches/minute lockup velocity when procuring snubbers. In actual application on a particular piping system, the snubber might be able to develop its required stiffness at a lockup velocity of 80 inches/minute. However, the technical specification and inservice inspection requirement typically is still set at the 30 inches/minute that was defined in the snubber procurement specification or vendor catalog. Therefore, a snubber that when tested in service had a lockup velocity of say 50 inches/minute would require maintenance or replacement even though it would still be able to perform its required function.

There have been over 500 separate incidents of snubber malfunction or out-of-operating tolerance reported in safety-related nuclear power plant piping in the period from 1973 through 1983 as shown in Appendix F. Snubber incidents involving snubber malfunction or out-of-operating tolerance must be rated as one of the more common events occurring in safety-related piping systems in nuclear power plants today. It should also be understood that snubber incidents, even though they are rather common occurrences, are not considered a design basis event. Therefore, consequences of postulated snubber events in general have not been evaluated.

Reported snubber malfunction events have in most instances led to the loss of seismic restraint, which does not imperil normal operation. However, the less common lockup failure mode could lead to pipe rupture in normal or anticipated transient operation. This is all the more a concern because such snubber failures appear to be time dependent. During preoperational or startup testing, the snubber may function as designed but leakage of seals or corrosion that is quite time dependent may cause malfunction at a later date. In addition, actual piping system failure or rupture as a result of snubber malfunction tends also to be time dependent. Cyclic high stresses induced in the operating system by snubber restraint of thermal expansion potentially lead to low-cycle fatigue failures of the piping. However, it should be emphasized that while there have been approximately 25 lockup snubber incidents reported in nuclear plants in the period 1973 through 1983, there is no known instance to date where snubber failure has led to pipe rupture or leakage. This number is undoubtedly low because, as noted in a recent AEOD engineering evaluation report [Ref. 4-8], the current NRC requirements for visual inservice inspection for

mechanical snubbers are not adequate to detect lockup mechanical snubbers in operating plants. More than 100 mechanical snubber failures were reported in response to IE Bulletin 81-01 [Ref. 4-4] but were not in the LER data system.

Because of (1) the relatively high rate of snubber failure, (2) the potential for catastrophic failure (rupture) of high-energy safety-related piping systems in the operating as well as the seismic loading condition, and (3) the time-dependent nature of the failures, it is easy to understand the stated desire on the part of the NRC and the nuclear industry to reduce the use of snubbers. This desire or need for snubber reduction must be balanced against the ease and convenience from an analytical and design standpoint that the use of snubbers has had in meeting current design criteria, principally the requirements of Section III of the ASME Boiler and Pressure Vessel Code.

The picture is further clouded by the fact that by 1984 most nuclear power plant piping systems and their supports have been designed and the hardware is on order. Any effort now to reduce or limit the use of snubbers would require an extensive and expensive piping system redesign and analysis effort. Regardless of the long-term benefits of increased safety and reduced maintenance costs, it is understandable that utilities would be reluctant to embark on an overall reanalysis of their safety-related piping systems with the negative impact on schedule and costs unless the resultant benefits are significant and clearly identified.

One other problem area associated with snubbers is their use as vibration-control devices. The term vibration as used herein is limited to operational vibrations associated with steady-state flow and rotating equipment operation. Such vibrations are characterized by a large number of cycles ($> 10^4$) and small amplitudes. Snubbers do not perform well in such environments and are subject to considerable degradation. Hence, their use as vibration-control devices is not recommended.

Cost-Benefit Considerations

In Reference 4-5, two operating nuclear plants provided information regarding snubber maintenance, inspection, and repair costs. Plant A was completed in 1972 and used only hydraulic snubbers. Plant B was completed in 1976 and used both hydraulic and mechanical snubbers.

Plant A required 600 person-hours to inspect 1,000 snubbers. Snubber inspection occurs every 6 months. A second inspection of questionable snubbers requires approximately 20 person-hours per inspection period. Seals are replaced every 6 years in Plant A. Approximately 167 snubbers have seals replaced every year at a cost of \$4,000 per snubber. Maintenance and inspection costs for 1,000 snubbers is approximately \$1,000,000 per year or \$1,000 per snubber per year. Snubber failures have not caused reactor shutdown since the plant has 300 spare snubbers for use as replacement hardware.

Plant B has 650 snubbers and requires \$250,000 for maintenance, inspection, and repairs per year or \$385 per snubber per year. Approximately 150 person-hours are required to perform inspections. Plant B has 100% inspection per year. There is no reactor downtime because of a large snubber inventory.

Based on very limited data, cost of inservice inspection on snubbers is ranging between \$385 to \$1,000 per snubber per year at an average cost of \$690 per snubber. Assume there are a total of approximately 300 hot lines containing an average of five snubbers per line for a total of 1,500 snubbers per plant. A rather large spare snubber inventory of typically 300 snubbers or 20% of the installed number of snubbers at a capital cost of \$600,000 is also maintained per plant. For lines with an average spacing between snubbers of 16 feet or less and assuming a 50% elimination rate and an average of \$80.00/ft of line for reanalysis to eliminate snubbers, the payback in reduced snubber maintenance, inspection, and inventory costs would take less than 4 years. Obviously as snubber density per line increases, the payback period would decrease. Currently, the radiation dosage estimated for the snubber maintenance and inspection program is 40 person-rem/s per year per plant [Ref. 4-14]. Therefore, added to the direct economic considerations should be the benefit of reduced radiation exposure to plant personnel associated with the reduced number of snubber inspections and maintenance.

Status of Ongoing Efforts To Resolve Problem of Excess Use of Snubbers

The nuclear power industry, primarily in support of the PVRC Technical Committee on Piping Systems of the Welding Research Council, has embarked on a multiyear effort to reduce the perceived seismic overdesign of piping systems that reduces overall piping system reliability and plant safety. As part of this effort, a technical position on industry practice [Ref. 4-1] has been prepared by the Task Group on Industry Practice of the PVRC Technical Committee on Piping Systems. This document summarizes the current position of the Task Group on snubbers and their use and as such represents industry opinion on the subject. While the industry position cites cost as a major consideration in a snubber reduction or limitation program, it also identifies the negative impact of the use of snubbers on piping system reliability.

A general industry standard applicable to the examination and performance testing of nuclear power plant snubbers has been published [Ref. 4-15]. This standard, however, does not contain any advice on the general applicability or advisability of the use of snubbers. Industry practice and recommendations regarding the use of snubbers can also be found in Reference 4-16.

The NRC's most recent concern regarding the use of snubbers has been focused by the initiation of the NRC Piping Review Committee activity [Ref. 4-17]. Prior to this time, Generic Issue A-13 was created for improved snubber operability and reliability. Solutions were prepared in NUREG-0371, which consisted of an evaluation of industry practices associated with snubber design and qualification testing and development of technical specification and regulatory changes to enhance snubber reliability. SRP Sections 3.9.2 and 3.9.3 were made more detailed in their treatment of snubbers a draft regulatory guide to ensure a high level of snubber operability was completed. However, none of the NRC effort to date was focused directly on the reduction or elimination of snubbers until the current NRC Piping Review Committee began its effort. The concerns raised by the recent AEOD/E406 [Ref. 4-8] regarding mechanical snubber lockup can only increase the benefits to be derived from a significant snubber reduction program.

4.2.2 Consultant Suggestions on Use of Snubbers

Before making specific recommendations, it is necessary to review the current status of the use of snubbers in nuclear power plants. Before any recommendations presented in this report could be implemented (1985 at the earliest), it is expected that at least 90% of all potential snubber usage associated with the initial installation of nuclear power plant piping supports will be completed or beyond the active design phase. Therefore, any program recommending that snubber use be modified, changed, or otherwise reduced in order to significantly improve piping system reliability and safety should be applied to operating plants and plants nearing operation as well as any that may still be in an active design phase. Since the SRP and many other standards are geared to plants in the active design phase, any change to these criteria would have little impact on most U.S. nuclear plants. Before deciding it is necessary to limit the use of snubbers, the effects of various snubber reliability improvement programs should be carefully considered.

If review of current efforts to improve snubber reliability is not considered effective, it is recommended that any NRC-sponsored program to limit or reduce snubber usage should be applied to operating plants and plants nearing operation as well as those plants in the active design and construction phases. Given the added cost of any program to limit or reduce snubber usage, primarily in the form of additional engineering to reanalyze piping systems with snubbers deleted, it would appear prudent to provide an offsetting benefit in the form of significant reduction in the number of snubbers needed plantwide. While no detailed cost-benefit analysis has been performed, it is expected that a snubber reduction in the range of 40 to 60% would be required to offset the added cost of the analysis effort. It should also be noted that snubber reduction can be performed independently on a line-by-line basis. Therefore any snubber-reduction program could concentrate on lines with the highest snubber density to maximize initial payback. As discussed, a 50% snubber-reduction program should pay for itself in less than 4 years and thereafter result in a cost savings of over \$500,000 per year per plant for plants currently containing 1,500 or more snubbers.

It is our judgment that the increase in the damping recently proposed by the PVRC piping committee [Ref. 4-18] would provide about half the 50% reduction. Additional significant reductions could be gained by implementing the suggestions of Campbell [Ref. 4-19], Broman [Ref. 4-20], Stevenson [Ref. 4-21], or Brookhaven National Laboratory (BNL) [Ref. 4-22]. Implementation of the recommendations of Campbell and Broman, which effectively increase seismic allowable stresses, would also require changes to the current ASME Code. Stevenson's procedure, which reduces seismic response spectra inertia forces by permitting implicit nonlinear response, and BNL's modification of input motion as a function of independent support motions would not require any modification of the current ASME Code mandatory requirements. In order to provide a balanced cost-benefit relationship, any NRC program to reduce or limit snubber usage would have to incorporate or permit the use of a combination of these proposed changes.

The following specific regulatory action recommendations are made:

1. For all nuclear power stations, an NRC program should be implemented that strongly encourages a reduction in the use of or elimination of snubbers.
2. The NRC regulatory requirements in conjunction with the snubber-reduction program should be modified to permit the use of higher damping and other recommended criteria changes given in this document.
3. Consideration should be given to developing snubber inservice testing qualifications that are directly related to required or minimum piping support parameters (e.g., overall snubber stiffness) rather than nominal snubber operating parameters (e.g., bleed rate, lockup velocity, dead band).

As discussed previously, changes to existing detailed regulatory requirements that are limited to the SRP will have little direct impact on snubber applications in the foreseeable future since very few plants are still in an active design phase and none are undergoing Construction Permit review. However, the following detailed changes to applicable SRP requirements are recommended:

1. Delete reference or implication that snubbers should or could be used to control vibration. It is not recommended that snubbers be used to control operational vibration [Ref. 4-1].
2. The basis of the 2,500-cycle limit for snubber fatigue analysis should be explained. It is recommended that the limit used on snubber cyclic behavior be made consistent with the safety factors used on other design aspects of piping and supports.
3. Recent research concerning the response of piping systems to vibratory excitation [Ref. 4-23] indicate that higher damping is increased when larger support gaps are used. Regulatory requirements that minimize overall pipe support gaps within rational limits of ± 0.125 inches tend to reduce damping and thereby increase seismic stress in the piping system. Therefore, it is not in the best interest of nuclear safety to minimize total lost motion and gaps beyond some reasonable range, say ± 0.125 inches. It must be understood that the calculated stresses in real piping systems give only an index of the actual stress. Analysis based on linear-elastic system behavior and simplified boundary assumptions that ignore gaps and actual stiffnesses and certain classes of restraints such as spring hangers in seismic analysis at best give only an approximation of the true stress in the piping system.
4. The use of snubbers should be actively discouraged. One such approach might be to change the SRP to include the effects of a postulated single snubber failure in ASME Code piping and support analysis. It would also be necessary to modify the Service Limit D analysis to include an evaluation of thermal stresses in fatigue analysis for the locked snubber case. This is obviously a ratchet on current design procedures and should only be undertaken if it can receive a broad consensus of regulatory and industry support.

The following research programs are suggested:

1. Integrated Pipe Support Program

Given the critical effect that piping behavior has on nuclear plant safety, it is essential that a major NRC research program continue in this area. This is particularly true considering the dearth of knowledge that exists regarding how industrial piping behaves and potentially fails in real earthquakes. At present there is not even a clear understanding in the industry, much less agreement, as to how pipes fail in real earthquakes [Ref. 4-24]. As part of an overall piping research program, a better understanding is needed as to how snubbers and other types of supports act as part of a real piping support system when subjected to repeated thermal and cyclic seismic differential support motion.

Specifically, the tight NRC-mandated dimensional requirements, operating parameter limits, and tolerances intended to improve snubber reliability are difficult to meet at initial manufacture and installation and impose significant and costly maintenance and inservice inspection requirements on snubbers during the operating plant life. More important, currently the regulatory-required minimization of gaps, tolerances, and overall support flexibility in piping systems may actually result in increased seismic and thermal stresses in the piping systems because of the resultant reduction in damping and increased thermal restraint. Carefully controlled multidirectional, multiple independent support, strong motion, and elevated-temperature testing of real piping systems is essential to evaluate whether current regulatory requirements result in higher than necessary piping system stresses. It is strongly recommended that the NRC consider developing and sponsoring a significant research program geared toward an appraisal of piping and support performance, including snubbers when they are part of a real piping system and subjected to limiting design events and employing normal construction and fit-up tolerances. Considering the apparent strong influence that fit-up tolerances have on piping system damping, hence on resultant seismic stresses in the piping system, variations in such tolerances should be parameters evaluated during the pipe support test program.

2. Snubber Reliability and Operability Assurance Evaluation and Related Documentation

While there have been over 500 snubber failure LERs in the period from 1973 through 1983, only a small portion of these failures have been evaluated in detail [Refs. 4-2, 4-3, 4-5, and 4-6]. A comprehensive detailed study of snubber LERs and the backup documentation, including an accurate determination of the current snubber population, should be undertaken. The purpose of this study would be to identify the causes of snubber failure, both current and historical, including any trends in failure events. The information collected would also make possible an accurate cost-benefit analysis of any snubber improvement or reduction program. The effectiveness of the various snubber reliability improvement programs undertaken by the industry to improve snubber reliability should also be evaluated [Refs. 4-2, 4-3, 4-5, 4-6, and 4-25].

4.2.3 Task Group Recommendations

The Task Group has reviewed the above and makes the following recommendations regarding the use of snubbers:

o Action Items

- Initiate a nonmandatory snubber reassessment program for operating plants and plants under construction.

o Research Programs

- Encourage the nuclear industry to investigate methods and procedures to limit the use of snubbers.
- Complete the Pacific Northwest Laboratories' study of Licensee Event Reports related to snubber performance to identify failure causes and effectiveness of various snubber types, and suggest methods of improving performance such as periodic testing or qualification testing.

4.3 Piping System Design Responsibilities

4.3.1 Consultant Suggestions and General Discussion

While industry practice may vary according to the individual architect-engineering (AE) or consultant-engineering firm, the design of piping systems generally involves interaction between the following different engineering or design disciplines:

1. Systems engineering
2. Equipment design
3. Pipe layout or design
4. Pipe stress engineering
5. Support design
6. Construction engineering

A system having so many different engineering disciplines could, at times, result in complications and possibly unbalanced designs. Such designs could result in undesirable malfunctions of the systems and as such they deserve regulatory consideration.

The requirements to be satisfied for the design of piping systems are covered in Section III of the ASME and ANSI Codes and in Section 3.9 of the SRP. These requirements do not, in fact, prevent overdesign nor do they impose restrictions on the locations of supports. What is required is a demonstration that the calculated stresses are within the Code limits.

In recent years, pipe stress engineering has become a critical factor of the entire design process. Most often the stress engineer is more theoretically oriented with limited practical experience in machine design and construction. The model of the piping system and its supports is idealized by finite-element computer codes that are used for evaluating the forces, moments, and, consequently, the

stresses and safety of the system. The latter is accomplished by comparing the calculated values with the Code allowables.

In order to comply with these allowables, the stress engineer modifies his model by adding or deleting supports. While these changes can readily be made within the computer model, they may not be very simple to construct. Furthermore, because of the many disciplines involved, unless there is central responsibility and very good coordination, it is possible that the acceptable design produced by the stress engineer while satisfying the Code criteria may be overdesigned in that it contains too many supports, which may indeed lead to undesirable malfunctioning during plant operation. Moreover, the analysis-based design may specify supports that are difficult to construct, behave differently from the mathematical model, and may even be located in areas that do not lend themselves readily to inspection because of high radiation or lack of space.

Many of these concerns have been recognized by the industry. Recently, the PVRC Technical Committee on Piping Systems has prepared a position paper [Ref. 4-1] that addresses itself to many of these concerns.

With respect to the piping design process, the following needs exist in the industry:

1. An overall manager with a multidiscipline expertise in all areas pertaining to piping design, such as Items 1 through 6 of Section 4.3.1. This manager should have sufficient expertise to deal with technical problems that are specific to each of the disciplines. The manager should also be responsible for the optimization of the piping system design (i.e., best layout, minimum number of supports, simplest type of supports, consideration of interferences, and consideration of radiological consequences during inspections and modifications).
2. Guidelines to assist the manager in making decisions. These should be developed for new systems and for modifying existing systems.

4.3.2 Task Group Recommendations

The Task Group has reviewed the above and makes no recommendations on piping system design responsibilities.

4.4 Considerations for Support Design

4.4.1 Consultant Suggestions and General Discussion

Most of the recently constructed plants have ended up with substantial numbers of supports. A typical recent PWR plant of 1100 MWe capacity could have as many as 9,000 or 10,000 supports for the Seismic Category 1 piping. Similar conditions with respect to supports exist for 1100 MWe BWR plants. The design, construction, assembly, and inspection costs for these supports are substantial. Furthermore, when dealing with many supports, the possibilities of malfunction

(i.e., snubbers stuck during thermal events) are always greater. In view of this, any considerations that could minimize supports should be investigated. This section deals with such approaches. The methods discussed below can be applied to new systems as well as to reducing the number of snubbers and supports in existing systems.

Current Methods

The design of piping supports in a nuclear power plant involves a time-consuming process that fluctuates among the requirements of the thermal, dynamic, and seismic loads. There are many variables in this type of design. Optimization procedures are not simple to define since the design problem is complex with conflicting requirements that are not easily accommodated.

Although the current piping support design procedures vary with each AE, they generally incorporate the notion of initial spacing of supports. This spacing is usually evaluated on the basis of the geometry and properties of the material (i.e., weights, etc.) between the supports and essentially uses a one-degree-of-freedom concept for the piping system. The basic idea is to place the fundamental frequency above the range of the exciting spectrum. Accordingly, the piping system can be characterized as "stiff," which implies that there are many supports.

Any method for determining the number and placement of piping supports is now acceptable as long as it satisfies the Code criteria and produces forces, moments, accelerations, deflections, and thermal characteristics that are within the prescribed limits. Regardless of how the number of supports was initially computed, a subsequent dynamic analysis must be carried out to confirm the compliance with the ASME Code.

Current methods for determining support spacing rely on considerations based mainly on natural frequencies. Alternative methods could also consider modal participation factors and damping in optimizing support locations.

Proposed Methods

Two different methods are proposed. These could be used either separately or together. The methods accept the concept that the piping system may have some natural frequencies that span the range of the exciting spectrum.

1. Method One

The first proposed method relies on the values of the modal participation factors for determining an initial look at piping support spacing. Consider the case where the mode with the largest modal participation factor is not associated with the fundamental mode. All other factors being equal, the maximum stress is also associated with this mode.

From a design point of view, an initial choice for the maximum piping support spacing could start with this mode natural frequency rather than the first. This is based on the rationale that the largest amount of energy input is associated with the mode having the highest participation factor. This is the mode

that should be placed above the highest frequency in the excitation spectrum since the highest stresses will develop in this mode. The conclusions drawn from this spacing requirement could then be dynamically analyzed for acceptability. Modifications could be made as required. An iteration process based on this initial choice, which in essence requires fewer snubbers, supports, etc., to begin with, should quickly converge to a final design.

A Rayleigh method could be employed to give the approximate value of the natural frequency associated with the mode with the highest participation factor instead of the usual dynamic analysis.

In application to existing piping systems, the static deflection analysis would give the basic information regarding the likelihood that some of the snubbers could be removed without exceeding the allowable stress conditions. Of course, the final support configuration would have to undergo a dynamic analysis to show whether the estimates are actually borne out.

2. Method Two

The second proposed method pertains to the possibility of using the damped response of interactive systems to limit the piping system response.

Currently, relatively small-diameter branch piping is neglected in the analysis of piping systems. It is assumed that the small piping has no effect on the larger system. The possible interactive effects are not evaluated. This assumption is valid where the dynamics of the separate systems are in different frequency ranges and/or the mass effects of the smaller system are truly negligible. There may, however, be a range of smaller branch piping sizes where the interaction effects could be used to advantage in minimizing the response of the original piping system. For this type of situation, the effect of increasing the damping in the smaller system should also be examined.

The actual concept that is proposed relates to the action of a complex "dynamic absorber" in which a small mass and relatively small damping may go a long way in reducing the response of the main system. For transient excitation, the results are not as dramatic as for steady state where the reduction could be no less than startling, i.e., the type of occurrence that makes a believer out of those who witness it in person. Nevertheless, the piping excitation is imparted through the building, which may oscillate for enough cycles for the reduction in response to be significant.

The method was examined in the laboratory where a mass ratio was of about 1/50 between systems (i.e., the secondary piping system was 1/50 the weight of the main system). Both a substantial amplitude reduction and a significant frequency shift were observed. This demonstrates that secondary systems that are currently ignored could have an effect on the primary system that is not now considered.

Other Considerations for Supports

All supports used in current designs exhibit nonlinear characteristics. Conventional rigid supports contain clearance gaps that accommodate thermal axial movements. The same is true to a greater or lesser extent for other types of

support elements. For snubbers in particular, the force deflection characteristics are very nonlinear. The common analytic practice of modeling supports as linear presents errors.

It is commonly assumed that these misrepresentations will result in overestimates of system response and thus the current analysis methods provide conservative results. This, however, is not always the case. In fact, some results from the physical benchmark program currently being carried out at BNL do not confirm this assumption. For the simple ANCO Z-bend configuration where a gap existed at the central support, it was found that the predictions of response based on linear analysis underestimated the measured responses in the vicinity of the support by a factor of two. Poor correlation was also obtained for other systems subjected to test (Indian Point, HDR).

Other misconceptions also exist in placement of pipe supports in proximity to each other. Recent inspections at certain plants under construction identified significant findings regarding closely spaced safety-related pipe supports. The identification and analysis of safety-related piping systems to new dynamic loading (increased seismic or hydrodynamic loads) in addition to those already addressed in the original piping design resulted in the need for additional pipe supports to reduce piping stresses, valve accelerations, and support and nozzle loads. This in turn resulted in the installation of many supports (and snubbers), some in proximity to other existing supports. The misconception lies in the mistaken assumption that closely spaced supports will share dynamic loads equally. In the case of closely spaced supports, any significant differences in the pipe-to-support gap will cause the support with the smaller gap to absorb the load first. Similarly, in the case of snubbers, the dead-band characteristics of snubbers are such that one snubber will probably lock up before its adjacent companion preventing the second closely spaced snubber from experiencing the load. This disparity in load-sharing capabilities could possibly lead to the overload or overstress of the support that initially takes the full load, which could then result in inadequate support of the piping, overstressing the pipe, and the inability of the piping system to perform its intended function.

In view of the above, there are some questions concerning the conservatism associated with current methods.

Suggested NRC-Sponsored Research Programs

1. A research effort should be undertaken to develop and implement the proposed method (Method 1) to optimize support placements. Once developed, the method should be applied to representative piping systems. If substantial savings in supports can be shown to occur as a result of using the method, there is no reason why it cannot be automated and made available for general use.

As mentioned in the text, the method can be used for new systems as well as for reducing the number of supports and snubbers in existing systems.

2. A program to investigate the effect of small-diameter branch piping systems should be undertaken. This program should establish the conditions and range of effectiveness of the small-diameter pipes in damping the response of the piping systems. If the method can be made effective, natural frequencies in the range of the excitation spectrum will exhibit high damping.

The consequence of this type of design is to permit the natural frequencies to span the range of the excitation frequencies. The maximum response would be limited by the interaction with damped complex absorber. The number of supports and snubbers would then be sizably reduced.

Under this program it is also proposed that several existing complex systems be analyzed to demonstrate the advantages of this approach.

3. A program to study the combined characteristics of the pipe support systems should be undertaken to determine the level of conservatism associated with current design analysis practices. Potentially, the study could contribute to analysis modifications that more correctly predict the actual response. The limitations of current methods could also be delineated.
4. A method or procedure should be developed for assessing whether or not sufficient attention to optimization was incorporated into the designs.
5. An effort should be undertaken to study the effect of clearances in supports. These clearances cause the response to be nonlinear and thus their impact on linear analysis needs to be assessed.

Suggested PVRC Action Items

Guidelines to address the following items should be developed:

1. Flexible base plate designs that are usually considered rigid for design purposes but in actuality deflect when pulled.
2. U-bolt clamps that are assumed to have lateral resistance but in actuality have low-resistance capacity in that direction.
3. When dealing with large pipe sizes, the effects of backup structural stiffnesses to be accounted for in the simulations for the support stiffness.

Suggested ASME Actions

Corresponding to the proposed changes in seismic design, it is recommended that ASME consider new guidelines for support design.

4.4.2 Task Group Recommendations

The Task Group has reviewed the above and recommends that such an integrated approach to pipe-support system design be pursued. It makes the following specific recommendations:

o Action Items

- Encourage PVRC and ASME activities to review and improve piping support design criteria.

o Research Programs

- Encourage the nuclear industry to develop procedures to optimize support placement and minimize the number of supports.
- Encourage the nuclear industry to investigate the effects of support gap size and installation tolerances on piping system behavior for both seismic and thermal loadings.
- Encourage the nuclear industry to assess performance of various piping supports.

5. INTERFACING ISSUES WITH OTHER TASKS

The four task groups of the USNRC Piping Review Committee have in some cases addressed common issues. The summary report of the Piping Review Committee (NUREG-1061, Vol. 5) will discuss in detail how recommendations from the task groups integrate. A brief description of interfaces of this report (NUREG-1061, Vol. 2) is given below.

5.1 Dynamic Loads

Both Volumes 2 and 4 of NUREG-1061 encourage the use of independent support motion methods. However, the Task Group on Other Dynamic Loads and Load Combinations recommends detailed rules for implementing these methods. Additionally, both Task Groups address the question of inelastic analysis stress and strain limits for piping. The Task Group on Other Dynamic Loads and Load Combinations recommends that the status quo be maintained as reflected in Appendix F to the ASME Boiler and Pressure Vessel Code. The Task Group on Seismic Design, however, goes beyond this by stating the goals of new performance criteria that would establish a minimum margin against failure.

5.2 Degraded Piping

Volume 2 of NUREG-1061 does not make recommendations regarding degraded piping, but Volume 4 recommends that seismic capacity testing be performed for cracked piping. Volumes 1 and 3 discuss in detail the potential for and consequences of pipe cracking.

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APPENDIX A

SARGENT & LUNDY ENGINEERS NUCLEAR PIPING DATA

Table A-1

TYPICAL BWR PIPING (FOR 46 SUBSYSTEMS)

Subsystem	Predominant Nom. Pipe Size	Predominant Pipe Class	Modal Frequency (Hz)		
			1st	2nd	3rd
MS-01	10"	C	15.042	16.869	16.929
MS-02	10"	C	7.886	14.579	15.404
MS-03	10"	C	10.127	12.695	12.716
MS-04	10"	C	8.999	10.457	12.000
MS-20	1"	A	7.280	7.927	8.019
LC-01	2"	D	5.045	5.747	6.467
VG-02D	18"	D	3.70	4.03	8.0
VG-02A	18"	D	3.87	10.5	11.7
RI-05B	4"	B	5.1	8.1	8.1
LP-03	12"	B	2.749	6.862	8.298
VG-01	24"	Two	5.449	5.986	6.218
VG-01	18"	Two	5.449	5.986	6.218
CY-02	10"	D	9.57	13.563	23.474
VG-02A	18"	D	3.865	10.567	11.742
RE-08	8"	D	3.794	4.593	8.873
RX-01	4" & 6"	D	9.628	10.794	11.036
VP-07	4" & 8"	B	3.574	8.170	10.370
CM-05A	3/4 & 1/2"	B	45.19	52.66	55.16
CM-05B	1/2"	B	5.08	8.18	12.78
CM-05C	3/4 & 1/2"	B	28.48	42.59	44.98
CM-05D	3/4 & 1/2"	B	4.58	8.90	13.27
CM-05E	1/2"	B	24.99	27.79	35.17
VH-01	12"	B	43.38	44.34	161.29
MS-61	1-1/2"	B	4.73	6.198	7.613
MS-47	3/4"	B	3.5	5.8	7.8
RH-09D	14"	B	2.978	3.807	4.923
WR-01	2-1/2"	C	6.910	7.428	7.943
NB-14	3/4"	B	10.277	13.346	16.377
NB-14C	3/4"	B	13.2	19.2	20.9
FW-04	18" & 6"	A & C	6.965	7.129	7.500
CW-10	8" & 10"	D	37.979	50.000	56.561
Seismically Supported					
VP-09	4"	D	2.924	5.422	8.858
Seismically Supported					
WS-13A	4"	C	12.642	41.684	52.910
WS-11A	4"	C	14.691	45.704	56.818
WR-27A	2"	C	9.535	10.718	15.605
IN-01A	1"	B	44.504	45.167	47.529
AF-06B	4"	D+	12.776	15.124	15.567
LP-01	10"	B	6.598	12.452	14.628
ILVC-05	1/2"	C	8.400	9.436	12.844
AF-04B	6"	D+	7.923	13.268	13.833
RI-2A	2"	B	4.451	7.031	8.690
CM-06A	3/4"	B	7.601	13.650	16.137
RH-62	4"	C	8.247	8.718	8.74
AF-06A	4"	D+	18.268	21.349	23.299
WR-26A	2"	C	9.600	10.543	13.644
RI-17	1"	B	4.319	7.483	8.454

Data Source: 9/27/83 letter from E.B. Branch to PVRC

KEY FOR SYSTEMS IN TABLE A-1

MS	-	Main Steam
LC	-	MS Iso Valve Leakage Control
VG	-	Standby Gas Treatment
RI	-	Reactor Core Isolation Cooling
LP	-	Low-Pressure Core Spray
CY	-	Cycled Condensate Storage
RE	-	Reactor Equipment Drains
RX	-	Reactor Building Floor Drain
VP	-	Containment HVAC
CM	-	Containment Monitoring
VH	-	Pump House/Screen House Piping
RH	-	Residual Heat Removal
WR	-	Reactor Building Closed Cooling Water
NB	-	Nuclear Boiler
FW	-	Feedwater
CW	-	Circulating Water
WS	-	Service Water
IN	-	Instrument Nitrogen
AF	-	Auxiliary Feedwater
ILVC	-	Instrument Line Control Room and Auxiliary Equipment Room HVAC

Table A-2

SUMMARY OF FUNDAMENTAL FREQUENCY RANGES FOR ALL CATEGORY I
SUBSYSTEMS IN TYPICAL BWR

Range of Frequencies (Hz)	Number of Subsystems	Range of Frequencies (Hz)	Number of Subsystems
0 - 1	3	32 - 33	3
1 - 2	28	33 - 34	2
2 - 3	35	34 - 35	2
3 - 4	37	35 - 36	1
4 - 5	26	36 - 37	1
5 - 6	21	37 - 38	2
6 - 7	22	38 - 39	0
7 - 8	19	39 - 40	1
8 - 9	10	40 - 41	1
9 - 10	11	42 - 43	1
10 - 11	13	44 - 45	1
11 - 12	14	47 - 48	1
12 - 13	4	49 - 50	1
13 - 14	5	50 - 51	1
14 - 15	11	52 - 53	1
15 - 16	9	55 - 56	1
16 - 17	4	57 - 58	1
17 - 18	5	58 - 59	4
18 - 19	4	61 - 62	1
19 - 20	3	63 - 64	1
20 - 21	1	69 - 70	1
21 - 22	3	72 - 73	1
22 - 23	2	75 - 76	1
23 - 24	1	94 - 95	1
25 - 26	3	104 - 105	1
26 - 27	3	106 - 107	1
27 - 28	2	127 - 128	1
28 - 29	1	167 - 168	1
29 - 30	1	186 - 187	1
30 - 31	1	235 - 236	1
31 - 32	1		

Note: 212 out of 342 subsystems (62%) had first-mode frequencies at 10 Hz or below.

Data Source: 9/27/83 letter from E.B. Branch to PVRC

Table A-3
SAMPLE OF MODAL FREQUENCIES IN TYPICAL PWR (FOR 50 SUBSYSTEMS)

Subsystem	Pipe Size	Insulated (Yes or No)	Modal Frequency (Hz)		
			1st	2nd	3rd
Boric Acid Processing					
1. 1AB-05	4	Y	7.890	18.762	27.330
2. 1AB-10	3	Y	11.740	13.506	18.238
Auxiliary Feedwater					
3. 1AF-02	6,4	N	3.970	4.054	4.171
4. 1AF-03	8,6	N	3.300	5.404	5.853
5. 1AF-05	16,6,4	Y	3.072	3.150	3.390
6. 1AF-07	6,4	Y	3.295	3.691	3.965
7. 1AF-08	6	N	3.431	8.100	12.109
8. 1AF-09	4	N	4.198	4.985	5.685
9. 1AF-10	4	N	3.059	3.837	5.056
10. 1AF-12	4	N	2.983	3.106	3.927
Component Cooling					
11. 1CC-01	16,12	N	8.624	13.615	14.968
12. 1CC-06	4	N	7.616	8.327	9.020
13. 1CC-11	6,3	N	16.472	23.714	26.302
14. 1CC-12	6,3	N	9.411	12.660	18.215
15. 1CC-15	4	N	9.079	10.470	11.013
16. 1CC-16	3	Y	19.763	42.176	43.309
17. 1CC-17	4	N	7.791	10.769	11.550
18. 1CC-18	8,6	N	12.801	16.334	17.940
19. 1CC-41	3,2	N	10.096	3.282	14.434
20. 1CC-42	3	N	6.001	6.825	14.661
Fuel Pool Cooling					
21. 1FC-01	10	Y	18.437	21.422	28.281
22. 1FC-03	10,14	Y	6.596	8.590	10.782
Fire Protection					
23. 1FP-03	6	N	9.783	14.778	17.085
24. 1FP-04	6	N	4.584	6.925	7.672
25. 1FP-13	4	N	7.161	10.896	12.067
26. 1FP-14	10	N	7.313	13.335	14.041
27. 1FP-15	10,4	N	7.830	8.199	10.306
28. 1FP-17	4	N	5.596	6.544	6.609
Fire Protection					
29. 1FP-19	6,4	N	6.907	7.261	7.536
30. 1FP-29	4	Y	6.326	9.129	9.427
31. 1FP-32	4	N	5.303	6.913	8.199
32. 1FP-40	4	N	6.533	9.218	11.667
33. 1FP-46	4	N	3.821	5.838	5.860
34. 1FP-50	10	N	6.603	11.738	13.885
Feedwater					
35. 1FW-16	3	Y	6.572	7.950	11.375
36. 1FW-17	3	Y	6.575	8.302	8.243
37. 1FW-18	3	Y	5.107	6.870	13.006
38. 1FW-19	3	Y	5.102	6.846	12.723
Essential Service Water					
39. 1SX-01	36,20	Y	9.142	12.449	12.757
40. 1SX-04	12,8,6	N	4.206	6.750	8.773
41. 1SX-10	20,16,10	N	7.366	8.398	10.022
42. 1SX-12	16	N	11.163	12.807	16.875
43. 1SX-16	10	Y	3.341	10.700	12.439
44. 1SX-25	30,20	Y	14.984	16.600	17.550
45. 1SX-28	12,16	N	15.788	19.048	24.231
46. 1SX-41	3,2	Y	7.637	8.897	9.107
47. 1SX-62	3,2	N	10.491	12.940	16.565
Chilled Water					
48. 1WO-26	6	Y	15.803	18.288	21.441
49. 1WO-27	4,3	Y	14.493	15.074	16.609
50. 1WO-29	6	Y	13.611	18.519	21.177

Note: All lines water filled

Data Source: 9/27/83 letter from E. B. Branch to PVRC

APPENDIX B

BECHTEL POWER CORPORATION NUCLEAR PIPING DATA

SUMMARY

	<u>PWR</u>	<u>BWR</u>	<u>TOTAL</u>
Number of Stress Calculations Reviewed	28	25	53
Number of Stress Calculations where "fn" is			
< 10	16	17	33
10 to 20	12	7	19
> 20	-	1	1

Table B-1

FREQUENCIES FROM 28 SUBSYSTEMS OF PWRs

Stress Calc. No.	Pipe Size (NPS)	<u>Modal Frequency (Hz)</u>		
		<u>1st</u>	<u>2nd</u>	<u>3rd</u>
P-311	42	15.26	16.75	23.50
P-9A	30, 24	8.74	9.22	9.57
P-94	30	4.56	9.83	14.40
P-1	28	9.96	11.10	13.33
P-26	28	11.22	14.87	15.49
P-24B3	20	12.20	15.59	16.76
P-2B	14	11.97	18.54	21.88
P-3A	14	13.71	15.44	15.85
P-44A	12, 10, 8	13.29	13.90	14.53
P-15	10, 8	3.96	5.87	6.10
P-19	8, 6	5.68	9.60	9.97
P-70	8, 6, 4	10.82	11.15	11.68
P-60	4	10.55	10.68	11.74
P-199	4	10.22	10.86	11.81
P-18	4	8.23	8.32	10.54
P-90	3, 2	6.95	7.26	7.71
P-14	14, 12	7.58	10.69	11.45
P-277	2	8.23	10.77	12.49
P-210	2	2.6	6.23	8.10
P-29A	2	5.56	7.13	8.91
P-530	2, 1	10.47	10.52	10.71
P-33	2, 1	10.52	11.51	12.31
P-547	1	8.84	11.51	12.31
P-546	1	15.05	18.73	19.27
P-531P1	1	5.88	5.99	6.06
P-531P2	1	5.67	6.71	7.29
P-540	1	4.61	5.95	11.70
P-581	3/4, 1	5.47	5.64	6.14

Table B-2
FREQUENCIES FROM 25 SUBSYSTEMS OF BWRs

Stress Calc. No.	Pipe Size (NPS)	Modal Frequency (Hz)		
		1st	2nd	3rd
12	4, 6, 8, 12, 16	15.19	16.18	27.05
45	18, 20, 24	5.64	5.97	6.17
56	14	6.01	11.56	12.88
66	12	14.70	19.08	26.00
69C	3, 4, 6, 8, 10, 18	7.14	7.49	8.01
75	12, 18, 24	11.23	11.73	13.81
92	6, 4, 8, 18	6.08	8.38	9.05
101	12, 14	13.37	13.78	26.56
106	2, 3, 4, 6, 8	8.30	9.08	9.20
217	10, 12, 16	10.06	10.80	14.0
302	2½, 3	5.69	7.77	10.9
323	20, 24	10.49	11.54	15.4
2028	¾, 1, 1½, 2	4.64	5.35	6.5
2027	¾, 1, 1½, 2	6.01	6.74	6.81
2021	¾, 1	5.52	14.17	15.5
2024	¾, 1½, 2	6.78	7.99	9.0
2081	¾, 1, 2	8.05	9.02	10.0
2086	¾, 1	6.00	7.94	10.5
2114	¾	3.89	14.01	16.83
2174	½, ¾	22.26	28.95	29.9
2259	¾	3.46	3.76	4.9
2280	2, 2½	4.10	7.96	8.19
2254	¾	3.14	3.60	3.74
2191	¾	3.18	5.98	6.51

APPENDIX C

DUKE POWER COMPANY NUCLEAR PIPING DATA

Data Collected from One PWR Plant

<u>Size Range</u>	<u>No. of Piping Systems Reviewed</u>	<u>First Mode Frequency (Hz)</u>	<u>First Piping Mode Frequency (Hz)</u>
3/4" - 2"	6	10.5	21.5
6"	31	4.0	9.2
8"	11	3.3	4.3
10" - 12"	23	3.1	4.0

APPENDIX D

GENERAL ELECTRIC COMPANY NUCLEAR PIPING DATA

Frequencies in BWR 6 Piping

<u>Line ID</u>	<u>Nominal OD (inch)</u>	<u>Frequencies (Hz)</u>		
		<u>F1</u>	<u>F2</u>	<u>F3</u>
Main Steam	26 (Line A-Inner)	7.31	9.02	10.94
Main Steam	26 (Line C-Outer)	7.20	8.82	10.95
Recirculation B Loop with RHR Line	20 (RHR)	15.72	16.02	21.04
	12 (Risers between header and vessel)	17.47	43.0	48.8
	22 (Header)	17.85	22.3	23.6
	28 (Pump suction/discharge)	28.7	30.2	31.3
RHR/LPCI Piping	12	12.21	15.51	17.50
RHR Suction Piping	16	9.30	10.01	10.33
Fuel Pool Cooling and Clean up	6	9.69	12.12	
	4			13.73
Reactor Water Cleanup	4	9.62	11.74	14.5

APPENDIX E

COMPOSITE-SYSTEM AND CROSS-CROSS FLOOR SPECTRA METHODS FOR SECTION 2.7

Introduction

The conventional floor spectrum method has several serious deficiencies. First, it neglects the effect of interaction between the primary structure and the piping system. This can be very significant when one or more frequencies of the piping system are in resonance with the frequencies of the primary structure. Neglecting interaction usually results in an overestimation of the response, which in some cases can be by as much as several hundred percent.

Second, the modal combination rules in use are ad hoc in nature and do not properly account for important effects, such as correlation between support motions and correlations between modal responses of the piping system. These rules are also inadequate to account for the correlation that exists between the "pseudostatic" and "inertia" components of the response. The result is that the estimated responses can be in gross error, both on the conservative side as well as on the unconservative side.

Finally, since time-histories are used to generate floor spectra, the conventional method of analysis is computationally very time consuming and costly. The main benefit of the floor spectrum method is that analysis of the piping system is decoupled from that of the primary structure.

This appendix briefly describes two new methods for seismic analysis of piping systems in nuclear power plant structures. The two methods are based on fundamental concepts of structural dynamics, random vibrations, and perturbation theory and provide very accurate estimates of the piping response to seismic excitations. The effects of interaction and correlation between support motions and between modal responses are included in both methods. Furthermore, the methods do not require time-history computations or separation of the response into pseudostatic and inertia components (although computation of these components, if necessary, is possible) and, as such, are computationally efficient and simple to implement. The main difference between the two new methods is that in one method, the Composite-System Method, the responses of the piping system are given directly in terms of the ground response spectrum, whereas in the other, the Cross-Cross Floor Spectrum Method, the responses of the piping system are given in terms of an extension of the conventional floor spectrum. In both methods, analysis of the piping system is decoupled from that of the primary structure. Short descriptions of these two methods are presented below.

Composite-System Method

This method consists of two basic steps: (1) evaluation of modal properties (i.e., natural frequencies, damping ratios, and mode shapes) of the composite piping-primary structure system in terms of the modal properties of the piping

system alone and of the primary structure alone; and (2) evaluation of piping response by modal combination, employing the computed modal properties of the composite system and using the ground response spectrum as input.

The first step is carried out through application of perturbation techniques employing the relative lightness of the piping system in relation to the primary structure. Closed-form expressions are derived for the modal properties in terms of the known properties of the two subsystems. The expressions are quite simple and allow straightforward implementation of the method. Through this analysis, the composite system in general possesses closely spaced modal frequencies and nonclassical damping. The latter characteristic gives rise to complex-valued mode shapes. Details of the perturbation analysis are reported in Reference E-1 to this appendix.

In the second step, the computed modal properties of the composite system are used to obtain responses of the piping system in terms of the ground response spectrum. The modal combination rule used for this analysis accounts for the effects of closely spaced modes and the nonclassical damping nature of the system. Details of the modal combination rule are reported in References E-2 and E-3. In the remainder of this section, some important aspects and results of the method are described. Example applications are presented in the last section.

The research has identified four main characteristics of composite piping-structure systems that significantly affect responses of the piping system. These are tuning, interaction, spatial coupling, and nonclassical damping. Tuning occurs when one or more frequencies of the fixed-base piping system (i.e., the piping system with all support points fixed) are close to one or more frequencies of the primary structure. Because of the resulting resonance, responses of the piping system are amplified and can be very large. Also, in such cases the composite system has closely spaced modes that have highly correlated responses. Interaction between the piping system and the primary structure is due to the coupled nature of their motions. Usually, its effect is to reduce the response of the piping system from what one would compute if interaction were neglected. The reduction can be very significant (i.e., in tens of percentage), particularly at tuning and when the piping system has relatively large mass. In the Composite-System Method, the effect of interaction is included through the computed modal properties of the composite system.

Spatial coupling deals with the manner in which the piping system is attached to the primary structure. For example, a piece of pipe that is tuned to a particular mode of the primary structure will not be affected by resonance if it is attached near a zero point of the corresponding mode shape. In the Composite-System Method, the spatial coupling effect is included in terms of the stiffness matrix of the piping system and the mode shapes of the primary structure and of the fixed-base piping system. Nonclassical damping in the composite system arises when the modal damping ratios of the primary structure and of the piping system are unequal. Its effect is most prominent around tuning and increases with increasing difference between the damping ratios. Because of this character, the mode shapes of the composite system are complex valued and require special treatment.

In the Composite-System Method, the above four characteristics are represented, respectively, by the following four dimensionless parameters:

$$\beta_{ij} = \frac{\omega_{pi} - \omega_{sj}}{(\omega_{pi} + \omega_{sj})/2} \quad \text{tuning parameter} \quad (E-1)$$

$$\gamma_{ij} = a_{ij}^2 \frac{m_{sj}}{m_{pi}} \quad \text{interaction parameter} \quad (E-2)$$

$$a_{ij} = - \frac{k_{ij}}{m_{sj} \omega_{sj}^2} \quad \text{spatial coupling parameter} \quad (E-3)$$

$$\delta_{ij} = \frac{\omega_{pi}}{\omega_{sj}} (\zeta_{pi} - \zeta_{sj} \frac{\omega_{pi}}{\omega_{sj}}) \quad \text{nonclassical damping parameter} \quad (E-4)$$

where ω_{pi} , ζ_{pi} and m_{pi} are the frequency, damping ratio, and modal mass of mode i of the primary structure, respectively, and ω_{sj} , ζ_{sj} and m_{sj} are the frequency, damping ratio, and modal mass of mode j of the piping system, respectively. (Subscript p denotes primary and subscript s denotes secondary subsystem.) The term k_{ij} is related to the stiffness matrix of the unattached piping system and the mode shapes of the primary structure and the fixed-base piping system. This parameter is such that a_{ij} can be interpreted as the static displacement in mode j of the piping system when the primary structure is statically displaced into its i th mode shape.

From the perturbation analysis, the modal properties of composite piping-primary structure system are derived in terms of the above parameters. In particular, the modal frequencies and damping ratios are given as simple expressions in terms of modal frequencies ω_{pi} and ω_{sj} , damping ratios ζ_{pi} and ζ_{sj} , and the parameters β_{ij} and γ_{ij} . The modal vectors are given in the form

$$\phi_k^* = \frac{\sum_i a_{ki} \phi_{pi}}{\sum_j b_{kj} \phi_{sj}} \quad (E-5)$$

where ϕ_{pi} and ϕ_{sj} are the modal vectors of the primary structure and of the piping system, respectively, and a_{ki} and b_{kj} are coefficients representing, respectively, the contributions of mode i of the primary structure and mode j of the piping system in "constructing" mode k of the composite system. Simple expressions for these coefficients are given in terms of the above parameters and δ_{ij} defined in Equation (E-4). The coefficients a_{ki} and b_{kj} are, in general, complex valued when δ_{ij} is not zero. As a result, in such cases the mode shapes are complex valued, and the composite system possesses nonclassical damping.

To determine the response of the piping system in terms of the ground response spectrum, a new modal combination rule based on the CQC method [Refs. E-4 and E-5] is developed that accounts for both closely spaced modes and nonclassical damping [Ref. E-2]. The rule for the mean of the peak response, $u_{\max}$, is expressed as

$$u_{\max} = \left[\sum_k \sum_i A_k A_i \rho_{0,ki} - B_k B_i \mu_{1,ki} + C_k C_i \rho_{2,ki} S(\omega_k^*) S(\omega_i^*) \right]^{1/2} \quad (E-6)$$

where A_k , B_k , and C_k are modal participation factors, $\rho_{0,ki}$, $\mu_{1,ki}$ and $\rho_{2,ki}$ are modal correlation coefficients, and $S(\omega_k)$ is the ordinate of the ground response spectrum associated with the mode k of the composite system. In the above expression, the entire term inside parenthesis is given in terms of the derived modal properties of the composite system. Also, the effect of closely spaced modes is taken into account through the correlation terms, and the effect of nonclassical damping is included through the last two terms inside the parenthesis.

Cross-Cross Floor Spectrum Method

In this method, the response of the piping system is obtained in terms of floor spectra. However, to account for cross-correlations between modal responses and between support motions, it is necessary to extend the conventional floor spectrum concept. The new floor spectrum is defined to be proportional to the cross-correlation between responses to two fictitious oscillators attached to the primary structure at two support points. The spectrum, denoted by $S_{KL}(\omega_i, \omega_j)$ for floors K and L and oscillator frequencies ω_i and ω_j is called Cross-Oscillator, Cross-Floor Spectrum or, in short, Cross-Cross Floor Spectrum (CCFS). In the special case where $K=L$ and $i=j$, the CCFS degenerates into the square of the conventional floor spectrum.

In terms of the CCFS, the response of the piping system is given by

$$u_{\max} = \left[\sum_i \sum_j a_i a_j \sum_K \sum_L b_{iK} b_{jL} S_{KL}(\omega_{si}, \omega_{sh}) \right]^{1/2} \quad (E-7)$$

where a_i is in terms of the properties of the mode i of the fixed-base piping system, and b_{iK} is given in terms of the i th modal vector and the elements of the piping stiffness matrix associated with the K th attachment point. Note that the first two summations in the above expression are over the modes of the fixed-base piping system and the last two are over the support points.

In the CCFS method, the effect between the primary structure and the piping system can be included by assigning masses to the oscillators. The effect of nonclassical damping is also included through an approximation of the modal damping ratios. The method is capable of handling general cases of tuning and spatial coupling. A detailed report on the development of the method will shortly be published [Ref. E-6]. A summary report of the method is available in Reference E-7.

In order for the method to be practical, it is necessary to have an efficient method for generation of the CCFS. An efficient method has been developed by considering two models of the primary structure with attached oscillators (see Fig. E-1). The CCFS is given directly in terms of the ground response spectrum through the following CQC rule:

$$S_{KL}(\omega_i, \omega_j) = \sum_i \sum_j A_{iK} A_{jL} \rho_{0,ij} S(\Omega_{jK}) S(\Omega_{jK}) \quad (E-8)$$

where A_{iK} is the i th modal participation factor of the structure with the oscillator attached to the K th floor; $\rho_{0,ij}$ is the modal correlation coefficient; and $S(\Omega_{jK})$ is the ground response spectrum ordinate at the i th frequency of the structure with the oscillator attached to floor K . The modal properties of the two oscillator-structure systems are obtained through perturbation techniques in much the same way as described in the previous section.

Example Applications

As an application of the above methods, consider the example piping system attached to a five-story building, shown in Figure E-2. The modal masses, stiffnesses, damping ratios, and modal frequencies of the two subsystems are shown in this figure. Note that the first and fifth frequencies of the piping system are respectively tuned to the first and second frequencies of the primary structure. The ratio of masses of the two subsystems, m/M , is set to be variable so that the effect of interaction can be studied.

Table E-1 lists computed accelerations of the piping system for a ground pseudo-acceleration response spectrum of the form $S_a(\omega, \zeta) = g \sqrt{\pi/2000\zeta}$. The exact results in this table were obtained by considering the composite piping-structure system as a single unit and numerically solving the associated eigenvalue problem. Computed results based on the Composite-System Method and the CCFS method are shown in the third and fourth columns, respectively. These results correspond to a mass ratio of $m/M = 0.03$. Observe that both methods are in close agreement with the exact results, with the Composite-System Method being somewhat more accurate than the CCFS method.

To show the effect of interaction, exact results for $m/M = 10^{-5}$ were also computed and are shown in the fifth column. These may be regarded as results that ignore the interaction effect. By way of comparison, the effect of interaction in reducing the piping response is quite significant.

The Composite-System Method is very effective in computing floor spectra used in designing equipment items [Ref. E-8]. As an illustration of this, the floor spectrum for the top floor of a ten-story building is computed. The example building and its properties are shown in Figure E-3. For each frequency of the single-degree-of-freedom equipment, the modal properties of the equipment-structure system are computed from the perturbation expressions, and Equation (E-6) is used to determine the peak response of the equipment in terms of the ground response spectrum. For this example, the spectra of 20 artificially generated accelerograms shown in Figure E-4 were used. Connecting the

results for various equipment frequencies, the floor spectra shown in Figure E-5 are obtained. These spectra are for three different masses of the equipment and include the effect of equipment-structure interaction. To show the accuracy of the proposed method, exact results based on time-history calculations are also shown in this figure as black dots. Observe that there is close agreement between the two sets of results of all frequencies. Also note that the effect of interaction is rather significant, particularly at frequencies where the floor spectrum has a peak due to tuning the equipment with a structure mode.

The Composite-System Method is also used in generating cross-cross floor spectra. As an example illustration, selected spectra for support points 1 and 2 of the example in Figure E-2 are shown in Figure E-6.

Table E-1

ACCELERATIONS OF PIPING SYSTEM IN UNITS OF GRAVITY ACCELERATION

Node (1)	Exact (2)	Composite System Method (3)	CCFS Method (4)	Interaction Neglected (5)
4	1.32	1.34	1.30	3.30
5	1.74	1.77	1.79	4.76
6	1.43	1.45	1.39	3.82
7	1.73	1.73	1.68	4.68
8	1.26	1.26	1.15	3.17

Figure E-1. Oscillator-Structure Models Used in Generating Cross-Cross Floor Spectra

SECONDARY SUBSYSTEM:
 Nodal Mass = m
 Internodal Stiffness = k
 Connection Stiffness = k
 $k/m = 31.22 \text{ s}^{-2}$
 Modal Damping Ratio = 0.02

PRIMARY SUBSYSTEM:
 Floor Mass = M
 Interstory Stiffness = K
 $K/M = 200 \text{ s}^{-2}$
 Modal Damping Ratio = 0.05

GROUND ACCELERATION SPECTRUM:
 $\ddot{x}_g(\omega, \xi) = \xi \left(\frac{v_w}{2000\xi} \right)^{1/2}$

Modal Frequencies, rad/s

Mode	Primary	Secondary
1	4.025	4.025
2	11.750	5.588
3	18.520	8.494
4	23.790	9.678
5	27.140	11.410

Figure E-2. Example Piping-Structure System

Figure E-3. Example Equipment-Structure System

Figure E-4. Mean Pseudovelocity Spectra for 20 Artificially Generated Ground Accelerograms

Figure E-5. Floor Spectra at Tenth Floor of Example Building

Figure E-6. Cross-Cross Floor Spectra for Example Piping System

REFERENCES FOR APPENDIX E

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- E-8 T. Igusa and A. Der Kiureghian, "An Accurate and Efficient Method for Generation of Floor Response Spectra," Proceedings, ASCE Specialty Conference on Probabilistic Mechanics and Structural Reliability, Berkeley, CA, pp. 189-192, January 1984.

APPENDIX F

SNUBBER DEFICIENCY DATA REPORT, SUMMARY 1973-1983

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
1	1973	Hydraulic	Oyster Creek	52	Loss of fluid; failure of polyurethane seals	(2)
2	1973	Hydraulic (1)	Millstone Pt.	51	Loss of fluid	(2)
3	1973	Hydraulic (2) & (3)	Pt. Beach 1	10 & 9	Loss of fluid	(2)
4	1973	Hydraulic (1)	Pt. Calhoun 1	26	Loss of fluid	(2)
5	1973	Hydraulic (1)	Monticello	37	Loss of fluid	(2)
6	1973	Hydraulic (1)	Oyster Creek	2	Loss of fluid; failed spring loaded piston ring	(2)
7	1973	Hydraulic (1)	Pilgrim	1	Fluid discoloration; seal deterioration	(2)
8	1973	Hydraulic (1) & (3)	Browns Ferry 1	1 & 5	Loss of fluid	(2)
9	1973	Hydraulic (1)	Monticello	15	Loss of fluid	(2)
10	1973	Hydraulic (1)	Turkey Pt. 3	5	Loss of fluid	(2)
11	1973	Hydraulic (1)	Pt. Calhoun 1	4	Loss of fluid	(2)
12	1973	Hydraulic (1)	Millstone Pt.	6	Loss of fluid	(2)
13	1973	Hydraulic (1)	Oyster Creek	21	Loss of fluid	(2)
14	1973	Hydraulic (1)	Quad Cities 1	7	Unsatisfactory condition	
15	1973	Hydraulic (1)	Quad Cities 2	9	Loss of fluid	(2)
16	1973 (1974)	Hydraulic	Surry 1	-		(3)
17	1973	Hydraulic (1) & (3)	Dresden 2	9 & 1	Loss of fluid	(2)
18	1974	Hydraulic (1)	Oyster Creek	5	Loss of fluid	(2)
19	1974	-	Robinson 2	1	Bending of restraint caused by failure of pipe shoe to slide	Main steam line
20	1974	Hydraulic (1)	Indian Pt. 2	2	Loss of fluid	(2)
21	1974	Hydraulic (1)	Dresden 2	12	Loss of fluid	(2)
22	1974	Hydraulic (1) & (3)	Oyster Creek	30 & 9	Loss of fluid; some seal deterioration	In drywell (2)
23	1974	Hydraulic (1)	Millstone Pt.	3	Loss of fluid	(2)
24	1974	Hydraulic (3)	Quad Cities 2	4	Loss of fluid; cause unknown	(2)
25	1974	Hydraulic (1)	Oyster Creek	7	Loss of fluid	(2) In drywell
26	1974	Hydraulic (1)	Dresden 3	9	Loss of fluid	(2)
27	1974	Hydraulic (3)	Quad Cities 2	1	Loss of fluid	(2)
28	1974	Hydraulic (1)	Oyster Creek	3	Loss of fluid	(2)
29	1974	Hydraulic (1)	Indian Pt. 2	7	Loss of fluid	(2)
30	1974	Hydraulic (3)	Peach Bottom 3	136	Condition caused by dynamic movement followed by constant pressure (thermal movement)	Relief valve discharge and turbine bypass lines (2)
31	1974	Hydraulic (1)	Pt. Calhoun 1	8	Loss of fluid	(2)
32	1974	Hydraulic (1)	Millstone	5	Loss of fluid	(2)
33	1974	-	Arnold	1	O-ring had small cut; probably occurred during manufacture	

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
34	1974		Oyster Creek	1	Two small cuts on main cylinder shaft J-cup caused by burrs on piston	
35	1974	-	Palisades	1	Restraint pulled loose from the concrete pillar as a result of a water hammer competition of Na OH system	Suction line on low pressure safety injection pump
36	1974	Mechanical (6)	Browns Ferry 2	11	Lack of lubrication during assembly	(2) Pressure vessels RPV Yarway column
37	1974	Hydraulic (1)	Indian Pt. 2	1	Loss of fluid	(2) Inside containment
38	1974	Hydraulic	Indian Pt. 2	5	Loss of fluid (one with new seals)	(2)
39	1974	Hydraulic	Dresden 2	8	Loss of fluid; two leaked	(2)
40	1974	-	Browns Ferry 3	6	Lack of lubrication during assembly	(2)
41	1974	Hydraulic (2)	Quad Cities 2	1	Loss of fluid	(2)
42	1974	Hydraulic (3)	Three Mile Is. 1	3	Loss of fluid; 1) fluid line broken 2) loose locknut 3) failed seal	(2)
43	1974	Hydraulic	Oyster Creek	2	Loss of fluid	(2)
44	1974	Hydraulic	Peach Bottom 3	1	Loss of fluid; installation error	
45	1974	Hydraulic (1)	Ft. Calhoun	2	Loss of fluid	(2)
46	1974	Hydraulic	Pilgrim	1	Loss of fluid; leaking	(2)
47	1974	Hydraulic	Peach Bottom 2	1	Loss of fluid; loose adjusting screws	
48	1974	Hydraulic (1) & (3)	Browns Ferry 2	7 & 1	Loss of fluid; 1) misalignment of valve assembly 2) nicks found on seals	
49	1974		Peach Bottom 3	4	Cycling of bypass valve	Piping between the bypass valves and the main condenser
50	1974	Hydraulic (1)	Dresden 2	4	Loss of fluid	In drywell
51	1974	Hydraulic (3)	Three Mile Is. 1	1	Loss of fluid due to reservoir line breaking; installation error	Relief valve line
52	1974		Browns Ferry 1	4	3 Lost fluid 1 bad piston rod torn out of clevis	
53	1974	Hydraulic	Peach Bottom 3	6	On two, loose lock nuts allowed units to rotate. On one, the threaded extension to the cylinder was bent. Another was a failed piston.	Main steam relief valve
54	1974	Hydraulic	Three Mile Is. 1	1	Loose end caps	
55	1974	Hydraulic (3)	Cooper	6	Loss of fluid	(2)
56	1974	Hydraulic (1)	Dresden 2	3	Loss of fluid	(2) In the drywell
57	1974	Hydraulic (1) & (3)	Rosco Beco	13 & 3	Loss of fluid	(2)
58	1975	Hydraulic	Three Mile Is. 1	1	Loss of fluid; loose end caps	(2) Inside secondary shield

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
59	1975	Hydraulic (1)	Browns Ferry 2	4	Loss of fluid; on 2 units a small nick was found in the sealing surface to the piston	
60	1975	Hydraulic (3)	Cooper	1	Weld on extension to anchor bracket found broken; lack of penetration	
61	1975	Hydraulic (1)	Millstone	2	Loss of fluid; improper reassembly	In drywell
62	1975	Hydraulic (1)	Dresden 3	2 INOP 6 Low oil	Loss of fluid; O-rings pinched	In drywell
63	1975	Hydraulic (1)	Monticello	1	Loss of fluid; improperly installed seal	In drywell
64	1975	Hydraulic (1)	Monticello	3	Loss of fluid; cut O-rings	Outside drywell
65	1975	Hydraulic	Peach Bottom 3	1	Loss of fluid	In drywell
66	1975	Hydraulic	Dresden 3	1	Loss of fluid	
67	1975		Fitzpatrick	2-5	Water hammer; operation of RHR system with discharge not full of water	Containment spray line
68	1975		Palisades	188	Design deficiencies	
69	1975	Hydraulic (3)	Three Mile Is. 1	9	Paint on piston, in violation with instructions, caused piston to freeze	
70	1975	Hydraulic	Three Mile Is. 1	6	3) Loss of fluid 3) Defective valves	
71	1975	Hydraulic	Dresden 3	2	Unknown	
72	1975	Hydraulic (1)	Millstone 1	3	Loss of fluid; O-ring pinched	
73	1975	Hydraulic	Fitzpatrick	1	Water hammer	Containment spray header B
74	1975	Hydraulic	Fitzpatrick	2	Failed seals	In drywell
75	1975	Mechanical	Millstone 2	1	Lockup caused by non-removal of preset screw	Pressurizer safety line
76	1975	Hydraulic	Arnold	1	Improper installation stem was broken	
77	1975	Hydraulic (1) & (3)	Quad Cities 2	1 & 1	Leaks; loss of fluid	
78	1975	Hydraulic	Peach Bottom 3	1	Loose fitting; an elbow connecting the snubber to the reservoir was damaged	Outside the drywell
79	1975	Hydraulic	Three Mile Is. 1	1	Unit found to be disconnected; installation error	Inside secondary shield of the reactor
80	1975	Hydraulic (1) & (3)	Quad Cities 2	1 & 2	Leakage; loss of fluid	
81	1975	Hydraulic (1)	Dresden 2	6	Loss of fluid; improper installation	
82	1975	Hydraulic	Peach Bottom 2	5	Loss of fluid; leaking O-rings and seals	
83	1975	Hydraulic	Peach Bottom 2	2	Loss of fluid; seal leaks	
84	1975	Hydraulic	Hatch 1	5	Loosening of jam nuts due to steam pipe vibration allowed disconnection	MSL Safety relief valve

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
85	1975	Hydraulic (3)	Ft. Calhoun 1	1	Leakage; problem seems to be seal material compatibility with fluid and heat	
86	1975	Hydraulic (3)	Yankee Rowe	8	Did not meet criteria	
87	1975	Hydraulic	Monticello	1	Improper installation; improper orientation of the pipe clamp	Outside the drywell
88	1975	Hydraulic (1)	Dresden 3	1	Filler plug leak	In drywell
89	1975	Mechanical	Arnold	1	Bent rod; lockup	Instrument line
90	1976	Hydraulic (3)	Rancho Seco	-	Possible out of tolerance lockup and bleed rate on all snubbers	
	1976		Oconee 1, 2, & 3	-	Amendment to operating licenses that establish additional surveillance of hydraulic snubbers	
	1976	Hydraulic (1)	Brunswick	-	Amendment to operating licenses that establish additional surveillance of hydraulic snubbers	
93	1976	Hydraulic	Cook 1	3	Apparent water hammer; a hydraulic tube was bent, a reservoir feed pipe was snapped and a valve was broken	Main feedwater line to generator 4 inside containment crane
94	1976	Hydraulic (3)	Peach Bottom 3	1	Leaking fittings & seals	Reactor recirculation pump
95	1976	Hydraulic (3)	Peach Bottom 3	3	Leaking fittings & seals	
96	1976	Hydraulic (1)	Quad Cities 1	3	Loss of fluid; no apparent leakage	
97	1976	Hydraulic (1)	Indian Pt. 2	1	Loss of fluid through rod nuts	Discharge of accumulator 22
98	1976	Hydraulic (3)	Cooper	1	Broken reservoir control valve	
99	1976	Hydraulic (3)	Cooper	1	Loss of fluid; vibration loosened end cap	RHR Loop B
100	1976	Hydraulic	Three Mile Is. 1	1	Loss of fluid	Decay heat pump A Suction line
101	1976	Hydraulic	St. Lucie 1	6	5 had calibration plate misaligned 1 had leak through weep hole	
102	1976	Hydraulic	Salem 1	12	Corrosion caused 3 to jam; locking and installation screws had not been removed on 4 units	Pressurizer piping
103	1976	Hydraulic (1)	Millstone 1	8	Loss of fluid; 1 piston rod packing had degraded	
104	1976	Hydraulic	Brunswick 2	2	Loss of fluid	
105	1976	Mechanical (6)	St. Lucie 1	5	Oxidation of internal parts Lockup	
106	1976	Hydraulic (3)	Arkansas Nuc 1	12	Loss of fluid; none were considered inoperable	
107	1976	Hydraulic (3)	Dresden 2	2	Loss of fluid; both remained operable	Isolation condenser pipeway

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
108	1976	Hydraulic (3)	Cook 1	10	Out of adjustment; did not meet criteria for bleed or lockup	
109	1976	Hydraulic (3)	Peach Bottom 2	22	Loss of fluid; faulty seals	Main steam relief valve discharge lines, HPCI, main steam ring header recirc. pump, RWCV, core spray, feedwater
110	1976	Hydraulic	Brunswick 2	10	Loss of fluid; faulty seals	In drywell, RV head, main steam feedwater heater system
111	1976	hydraulic (3)	Cooper	6	Loss of fluid	
112	1976	Hydraulic (4)	Crystal River 3	numerous	Leaks; (faulty seals), loss of fluid	
113	1976	Hydraulic (3)	Quad Cities 1	1	Leak due to misalignment of seals	RHR to fuel pool cross-tie line
114	1976	Hydraulic	Brunswick 2	1	Loss of fluids	RHR Service water system
115	1976	Hydraulic (3)	Peach Bottom 3	5	3 had leaks due to faulty seals 1 was improperly installed 1 had leakage due to defective screw seals	Main steam relief valve, discharge lines, recirc. pumps control rod drive return line
116	1976	Hydraulic (3)	Davis-Besse 1	-	Concern about the new control valve design causing premature lockup	
117	1976	Hydraulic	Brunswick 2	1	Leakage through loose screws	
118	1976	Hydraulic	Arkansas Nuc 1	3	Loss of fluid; still operable	
119	1976	Hydraulic (3)	Vermont Yankee	3	Failed lockup criteria; fluid viscosity too low	
120	1976	Hydraulic (3)	Peach Bottom 3	1	Loss of fluid	
121	1976	Hydraulic (3)	Arkansas Nuc 1	3	Loss of fluid	
122	1976	(Hydraulic)	Dresden 1	3	Loss of fluid	Core spray line
123	1976	Hydraulic (3)	Maine Yankee	2	Loose mounting bracket; failed seal	
124	1976	Hydraulic (1)	Dresden 3	2	Loss of fluid	In drywell
125	1976	Hydraulic (1) & (3)	Quad Cities 2	1 & 3	Oil leakage around shafts through O-rings	
126	1976	Hydraulic (3)	Cooper	10	Loss of fluid	
127	1976	Hydraulic (3)	Maine Yankee	1	Leaking excessively; failed O-ring	Feedwater line 2
128	1976	Hydraulic (3)	Calvert Cliffs	8	Failed to meet bleed and lockup design specs	
129	1976	Hydraulic	Peach Bottom 2	3	Leaks/damaged reservoir	
130	1976	Hydraulic (1)	Ft. Calhoun 1	10	Leaks caused by nicks on O-rings	
131	1976	Hydraulic (3)	Cooper	1	Missing reservoir clamp allows reservoir to be knocked onto floor	
132	1976	Hydraulic (3)	Maine Yankee	1	Loss of fluid; failed shaft seal	Main steam line 3

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
133	1976	Hydraulic	Three Mile Is. 1	1	Damaged piston ring; probably due to improper installation	
134	1976	Hydraulic (3)	Quad Cities 2	1	Failed end cap gasket leak	
135	1977	Hydraulic (3)	Millstone 2	1	Loss of fluid; fluid tubing vibration loose	
136	1977	Hydraulic (3)	Ft. St. Vrain	1	leak due to loose pin gland	
137	1977	Hydraulic	Brunswick	1	Water hammer broke shaft	RHR
138	1977	Hydraulic	Ft. St. Vrain	4	1 had a broken reservoir mounting bolt, 1 had a gasket leak, 1 had restricted bracket movement, 1 had missing clevis pin	
139	1977	(Hydraulic)	Zion 1		Small leak in lockup screw adjustment gasket	Pressurizer enclosure; upper section
140	1977	Hydraulic	Arnold	1	Vibrated loose from wall	Fuel pool to RHR line
141	1977	Hydraulic	Arnold	8	Loose anchor bolts	RHR Suction line
142	1977	Hydraulic	Arnold	2	1 had a broken piston, the other was vibrated away from the wall	HPCI Turbine exhaust line aux. boiler to HPCI line
143	1977	-	Brunswick 2	1	Vibrated Loose from its anchor (the turnbuckle had unscrewed)	RHR B Steam condensing line
144	1977	-	Cook 1	2	Water hammer	Feedwater piping
145	1977	Hydraulic	Ft. St. Vrain	1	Loss of fluid; reservoir glass was loose	
146	1977	Hydraulic 1) & 3)	Quad Cities 2	4 & 1	Loss of fluid due to: 1) loose end cap 2) hardened seals and O-rings	
147	1977	-	Brunswick 1	1	Apparent water hammer	Steam condensing inlet line to RHR heat exchanger 1A
148	1977	Hydraulic	Arnold	26	11 had lost fluid 15 filed to meet criteria	
149	1977	Mechanical (6)	Arnold	13	Locked up; internal corrosion	
150	1977	Hydraulic	Brunswick 2	1	Attachment sheared in half due to improper installation	
151	1977	Hydraulic	Crystal River 3	1	Disconnected from the snubber eye to the pipe clamp	HP-Injection line in reactor building
152	1977	Hydraulic	Ft. St. Vrain	11	9 had loss of fluid, 1 had a bent piston rod and the other was missing a clevis pin	Main steam supply and controls
153	1977	(Hydraulic)	Three Mile Is. 1	45	Failed to lockup in tension and/or compression directions during testing	
154	1977	(Hydraulic)	Zion 2	1	Missing pin which connects snubber to pipe	CF-Residual heat removal system & controls
155	1977	Hydraulic (3)	Maine Yankee	-	Failed to meet lockup requirements	
156	1977	Hydraulic	Five Mile Pt. 1	4	Loss of fluid; snubber failed to lockup in either direction of travel	Emergency core cooling system and controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
157	1977	Hydraulic (3)	St. St. Vrain	1	Loss of fluid due to loose end caps	Feedwater systems and controls
158	1977	Hydraulic	Hatch 1	55	Low oil/incorrect bleed tension	CF-Residual heat removal system
159	1977	Hydraulic	Millstone 2	2	1 Contained air in cylinder; the other had a damaged compression lockup valve cage which prevented lockup	Main steam supply system HB
160	1977	Hydraulic	North Anna 1&2		Design deficiency - snubbers must be capable of movement during seismic and thermal growth	Main steam system CC
161	1977	Hydraulic	Zion 1	1	Loss of fluid; faulty thread seals	Emergency core cooling system
162	1977	Hydraulic (1)	Indian Pt. 2	1	Fatigue failure of clamp	HH-Condensate & feedwater
163	1977	Hydraulic (3)	Peach Bottom 2	2	1 had leaking reservoir, the other a loose locking nut allowing it to turn upside down	
164	1977	Hydraulic (3)	Peach Bottom 3	9	Loss of fluid; reservoir leaks, valve block	
165	1977	Hydraulic (1) & (3)	Browns Ferry 2	1 & 1	Loss of fluid; oil fill plug leaks	Coolant Recirc. system CB
166	1977	Hydraulic (1)	Arnold	5	Loss of fluid; faulty seals	
167	1977	Hydraulic (1)	Indian Pt. 2	2	Leak; still operable	Main steam HH-Condensate and feedwater
168	1977	Hydraulic	Panoco Deco	35	Failed to meet criteria	
169	1977	Hydraulic	Davis-Besse 1	1	Snubber found upside down; loose locknut	
170	1977	Hydraulic	Davis-Besse 1	2	Near end of travel - (lockup)	CC Main steam system
171	1977	Hydraulic	Surry 2	-	Failed to meet criteria	
172	1977	Hydraulic	Zion 1	2	Thread seal leak	HI-Steam generator blow down system SF-Emergency core cooling system
173	1977	Hydraulic	Three Mile Is. 1	45	Failed to lockup in tension and/or compression directions of travel	
174	1977	(Hydraulic)	Surry 1	3-7	Loss of administrative control	CC-Main steam system
175	1977	(Hydraulic)	Surry 1	1	Snubber found in fully extended position (lockup) due to vibration	
176	1977	Hydraulic	Ft. St. Vrain	12	5 had no fluid due to leaks 6 had piston rods bottomed out	
177	1977	Hydraulic	Zion 1	1	Thread seal leak	WB-Cool system for real auxiliary
178	1977	Hydraulic	Dresden 2	28	Loss of fluid	LH-Feedwater system
179	1977	(Hydraulic) (3)	Point Beach 1	1	Improperly set control valve	HH-Condensate & feedwater system
180	1977	Hydraulic	Zion 1	1	Loss of fluid; thread seal leak	CF-Residual heat removal system

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
181	1977	Hydraulic	Peach Bottom 3	1	Snubber found rotated 30° fluid could not get in it	SF-Emergency core cooling system
182	1977	Hydraulic	Peach Bottom 3	2	Both found rotated	CB-Coolant recirc. system
183	1977	Hydraulic	Zion 2	10	Loss of fluid probably due to high temp environment	CB-Coolant recirc. system
184	1977	Hydraulic	Zion 1	2	Loss of fluid; thread seal leak	HB-Main steam system
185	1977	Hydraulic	Rancho Seco	1	Loss of fluid; O-ring leak	CB-Coolant recirc. system
186	1977	Hydraulic (1)	Ft. Calhoun	1	Loss of fluid; zero leak	
187	1977	Hydraulic	Peach Bottom 3	1	Rotated due to loose locking nut	SF-Emergency core cooling system
188	1977	Hydraulic (3)	Pt. Beach 2	1	Loss of fluid; leak between cylinder & hydraulic block	CB-Coolant recirc. system
189	1977	Hydraulic	Peach Bottom 2	4	3 had valve blocks and 1 had O-ring leak	
190	1977	Hydraulic (3)	Ft. Calhoun	15	Loss of fluid	
191	1977	Hydraulic	Arkansas Nuc 1	1	Loss of fluid due to cracked ring	CB-Coolant recirc. system
192	1977	Hydraulic (1)	Browns Ferry 3	6	Loss of fluid; faulty seals	
193	1977	Hydraulic	Brunswick 2	5	1 had broken spring, 1 was missing internal O-ring, 1 was missing relief call valve	
194	1977	Hydraulic (3)	Vermont Yankee	3	Loss of fluid	CB-Coolant recirc. system
195	1977	-	Brunswick 1	1	Water hammer	SF-Residual heat removal system
196	1977	-	Anna	1	Loss of fluid; faulty seals	CG-Main steam system
197	1977	Hydraulic	Watspatrick	57	Snubbers built to old standards	
198	1977	Hydraulic	Peach Bottom 3	1	Loss of fluid; would lockup and bleed in compression, but not in tension	TF-Circulating water system
199	1977	Hydraulic (3)	Peach Bottom 3	1	Loose locking nut allowed snubber to turn upside down	SF-Emergency core cooling system
200	1978	Hydraulic (1)	Idaho 1	5	2 had broken accumulator springs 1 had a faulty seal	
201	1978	Hydraulic	Arkansas Nuc 1	4	Loss of fluid; faulty seals	CB-Coolant recirc. system
202	1978	Hydraulic	Surry 1	1	Inverted snubber due to vibration which loosened the locknut	HB-Main steam supply system
203	1978	Hydraulic (5)	Robinson 2	3	Failure to lockup due to the hydraulic medium being too thin	CG-Real cool clean-up system
204	1978	-	Surry 2		Movement restricted due to expansion during heat up	HB-Main steam supply system
205	1978	Hydraulic	Rancho Seco	2	Loss of fluid	HE-Turbine bypass system
206	1978	Hydraulic (3)	Ft. St. Vrain	4	Loss of fluid	
207	1978	Hydraulic	Dresden 3	5	Loss of fluid; seal deterioration	SF-Emergency core cooling system
208	1978	Hydraulic (3)	Cooper	1	Locknut not tightened; rotation of snubber	CF-Residual heat removal system

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
209	1978	Hydraulic	Three Mile Is. 1	1	Loss of fluid; pinched rod wiper seal	CC-Main steam system
210	1978	Hydraulic	Dresden 3	1	Loss of fluid; damaged seals	SF-Emergency core cooling system
211	1978	Hydraulic	Three Mile Is. 1	1	Failed to lockup; 2 damaged O-rings were found	
212	1978	Hydraulic (3)	Cook 1	1	Loss of fluid due to nicks in seals	
213	1978	Hydraulic	Quad Cities 1	2	Loss of fluid; faulty seals damage to pivot pin	
214	1978	Hydraulic	Zion 2	12	11 had loss of fluid 1 had a missing pin	
215	1978	Hydraulic	Calvert Cliffs	1	Loss of fluid; faulty seals O-ring	SF-Emergency core cooling system
216	1978	Hydraulic (3)	Nine Mile Pt. 1	1	Loss of fluid due to failed O-ring also vibration let pipe ring nut loosen	CH-feedwater system
217	1978	Hydraulic	Kewaunee	1	Loss of fluid due to failed seals	HB-Main steam supply system
218	1978		Surry 1	1	Mount plate bolts insufficiently embedded	
219	1978	(Hydraulic) (1)	Ginna	2	Failure to lockup in compression and tension modes due to check valve failure	HB-Main steam supply system
220	1978	Hydraulic	North Anna 1	1	Loss of fluid due to a loose fill port plug	HB-Main steam supply system
221	1978	Hydraulic (1)	Hatch 1	1	Loss of fluid due to faulty O-ring seal	CF-Residual heat removal system
222	1978	Hydraulic (3)	North Anna 1	1	Snubber found rotate 180° due to loosened locknut	HH-Condensate & feedwater system
223	1978	Hydraulic	Surry 1	1	Loss of fluid	
224	1978	Hydraulic	Brunswick 2	5	4 had cracked supports 1 had loss of fluid	CF-Residual heat removal system
225	1978	Hydraulic	Zion 2	10	Loss of fluid; faulty seals	CB-Coolant recirc. system
226	1978	Hydraulic	Kewaunee	1	Loss of fluid; faulty seals	HB-Main steam supply system
227	1978	Hydraulic	Turkey Pt. 4	20	Failed functionality testing due to wear on main cylinders	
228	1978	Hydraulic	Surry 2	2	Loss of fluid	
229	1978	-	Brunswick 2	1	Loose pipe clamp turned and caused a break at the piston end	CF-Residual heat removal system
230	1978	Hydraulic	Brunswick 1	6	4 had faulty seals and 2 had loose pipe clamps	CF-Residual heat removal system
231	1978	-	Pt. Beach 1	1	Snubber failed to lockup even after reassembly	CB-Coolant recirc. system
232	1978	Hydraulic	Quad Cities 2	2	Loss of fluid; faulty O-ring seals	
233	1978	Hydraulic (3)	San Onofre 1	9	Water hammer; 6 had failed piston rods and locknut threads, 3 leaked	HH-Condensate & feedwater

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
234	1978	Hydraulic	Palisades	2	Loss of fluid due to faulty O-ring seals	HH-Consensate & feedwater
235	1978	Hydraulic	Surry 2	2	Loss of fluid; faulty seals	
236	1978	Hydraulic (3)	Ft. St. Vrain	5	Loss of fluid; faulty seals	
237	1978	Hydraulic	Dresden 3	1	Loss of fluid; faulty control valve	CC-Main steam system
238	1978	Hydraulic	Brunswick 1	1	Loss of fluid; degraded seal	WA-Station service water system
239	1978	Hydraulic (3)	Cook 2	1	Loose rod end nut caused snubber to rotate 130°	
240	1978	Hydraulic	Zion 1	5	Loss of fluid; faulty seals	
241	1978	Hydraulic	Surry 1	1	Loss of fluid; faulty seals	
242	1978	Hydraulic	Beaver Valley 1	1	Vibration caused the pin connecting the piston rod to the clamp to fallout	HB-Main steam supply
243	1978	Hydraulic	Beach Bottom 3	1	Loss of fluid; fitting leak	HF-Circ. water system
244	1978	Hydraulic (3)	Beach Bottom 2	5	Failed to pass lockup and bleed criteria due to clogged bleed orifices	
245	1979	Hydraulic	Surry 1	2	Loss of fluid; tube fitting leaks	
246	1979	Hydraulic	Oconee 2	5	Loss of fluid	SA-Real containment system
247	1979	Hydraulic	Calvert Cliffs 2	1	An insufficiently tightened pipe clamp caused a piston rod to bend	HB-Main steam supply system
248	1979	Hydraulic (1)	Brunswick 2	1	Pully extended (lockup) due to loose pipe clamp	CF-Residual heat removal system
249	1979	Hydraulic	North Anna 1	1	Loss of fluid; damaged water seal	HH-Condensate & feedwater system
250	1979	Hydraulic (1)	Brunswick 2	1	Piston shaft unscrewed from rod eye	WA-Station service water system
251	1979	(Hydraulic)	Surry 2	19	Failed to meet criteria in the event of severe earthquake	
252	1979	Hydraulic	Surry 1	1	Loss of fluid; fitting leak	CB-Coolant recirc. system
253	1979	(Hydraulic) (1)	Brunswick 1	1	Snubber failed to lockup; no cause determined	
254	1979	Mechanical	Turkey Pt. 3	1	Locked up because of damaged thrust bearing	HB-Main steam supply system
255	1979	Hydraulic (2)	Pt. Beach 2	1	Loss of fluid; seal leak	HB-Main steam supply system
256	1979	Hydraulic (3)	Vermont Yankee	1	Loss of fluid; tubing connection leak	
257	1979	Hydraulic	North Anna 1	1	Loss of fluid; improperly seated O-ring	CB-Coolant recirc. system
258	1979	Hydraulic	Zion 2	3	2 found upside-down 1 disconnected at rod end	
259	1979	Hydraulic (1)	Brunswick 2	18	Loss of fluid; seal failure	CB-Coolant recirc. system
260	1979	Hydraulic	Oyster Creek	1	Failed to lockup in compression direction	SF-Emergency core cooling system

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
260A	1979	Mechanical (8)	Big Rock Pt.	8	Improper installation of spherical washer	
260B	1979	Mechanical (5)	FFTF	43	Locked up during construction inspection	
261	1979	Hydraulic	Fitzpatrick	2		
262	1979	Hydraulic	Palisades	2	Loss of fluid; failed O-ring	HB-Main steam supply system
263	1979	Hydraulic	San Onofre 1	1	Water hammer caused snubbers piston, rod, and locknut threads to fail	HH-Consensate & feedwater system
264	1979	(Hydraulic)	Nine Mile Pt. 1	1	Loss of fluid; worn seals	SF-Emergency core cooling system
265	1979	Hydraulic	Brunswick 1	6	Loss of fluid; seal leaks	
266	1979	Mechanical	Turkey Pt. 4	1	Design error; exact cause not known	CH-Feedwater systems
267	1979	Hydraulic	Pt. St. Vrain	-	Set pt. drift and dirty oil, and clogged valves	
268	1979	Hydraulic	Rancho Seco	2	Loss of fluid; wear to springs	HE-Turbine bypass system
269	1979	Hydraulic (1)	Indian Pt. 2	1	Loss of fluid	HB-Main steam supply
270	1979	Hydraulic	Brunswick 2	3	Loss of fluid; seal failure	CB-Coolant recirc. system
271	1979	Hydraulic	Oconee 1	3	1 Had its baseplate pulled from the wall and 2 had loss of fluid	HB-Main steam supply system
272	1979	Hydraulic	Robinson 2	1	Loss of fluid; seal leaks	CG-Reactor cool cleanup system
273	1979	Hydraulic	Barley 1	15	Seal leakage; did not meet lockup requirements	
274	1979	Mechanical (3)	Turkey Pt. 4	1	Snubber was found in lockup caused by damaged thrust bearing due to excessive load	HB-Main steam supply system
275	1979	Hydraulic (3)	Indian Pt. 2	1	Loss of fluid; tube fitting leak	HB-Main steam supply system
276	1979	Hydraulic	Brunswick 1	5	2 had loss of fluid 3 had loose pipe clamps	
277	1979	Mechanical (8)	Salem 1	3	Extreme shock load or when snubber is in full extension	HH-Condensate and feedwater
278	1979	(Hydraulic)	Brunswick 1	1	Snubber found fully extended	PB-Process sampling system
279	1979	Hydraulic	Beaver Valley 1	23	Failed to meet criteria; air cylinder wear ring problems	
280	1979	Hydraulic (3)	Pt. St. Vrain	2	Loss of fluid and slipped reservoir nut (loose)	HB-Main steam supply system
281	1979	Hydraulic (1)	Ginna	1	Constant movement of pipe caused wear on pipes	HB-Main steam supply system
282	1979	Hydraulic	Vermont Yankee	1	Loss of fluid; brittle seals	CB-Coolant recirc. system
283	1979	Hydraulic	Rancho Seco	2	Loss of fluid	HB-Main steam supply system
284	1979	Hydraulic (3)	Quad Cities 2	3	Loss of fluid; defective gaskets	CE-Reactor core
285	1979	Hydraulic	Pt. St. Vrain	1	Loss of fluid	
286	1979	Hydraulic	Brunswick 1	10	Water hammer	CC-Main supply system

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
287	1979	(Hydraulic)	Davis-Besse	1	Found upside down; loose jam nuts	CF-Residual heat removal system
288	1979	Hydraulic (1)	Indian Pt. 3	35	Defective	
289	1979	(Hydraulic)	Ft. St. Vrain	1	Missing a rod-eye piston pin	
290	1979	Hydraulic	Brunswick 1	5	Loss of fluid; 3 had loose pipe clamps	WA-Station service water system
291	1980	Hydraulic	Fitzpatrick	1	Loss of fluid; O-ring leakage	
292	1980	Hydraulic	Surry 1	1	Loss of fluid; seal leak	HH-Condensate & feedwater system
293	1980	Hydraulic	Brunswick 1	1	Damaged reservoir tube	CB-Coolant recirc. system
294	1980	Hydraulic (1)	Rancho Seco	7	Broken springs, worn poppets & seats, worn O-rings	HB-Main steam supply system
295	1980	(Hydraulic)	Brunswick 2	3	Leaks, slipped clamp, missing pin	CF-Residual heat removal system
296	1980	Hydraulic	Vermont Yankee	1	Loss of fluid; did not lockup within the required tolerances	
297	1980	Hydraulic	Ft. St. Vrain	1	Missing piston rod eye	HH-Condensate & feedwater system
298	1980	Hydraulic	Surry 1	1	Loss of fluid; bad reservoir fitting	CB-Coolant recirc. system
299	1980	Hydraulic	Millstone 2	2	Snubber clamp bolts fail due to vibration	HB-Main steam supply system
300	1980	(Hydraulic)	Dresden 3	1	Water hammer	CG-Real cool cleanup system
301	1980	Hydraulic	Rancho Seco	1	Loss of fluid	CF-Residual heat removal system
302	1980	Hydraulic	Ft. St. Vrain	3	Loss of fluid	CC-Main steam system
303	1980	Hydraulic	Hatch 2	1	Loss of fluid; seal leak	SC-Containment air port & cleanup
304	1980	Hydraulic	San Onofre 1	1	Loss of fluid; seal leak	
305	1980	Hydraulic	Palisades	4	Loss of fluid; worn seal	HB-Main steam supply system
306	1980	Mechanical (6)	Hatch 1	45	Lockup due to internal corrosion	
307	1980	Hydraulic (1)	Brunswick 2	1	Missing paddle brushing	WB-Cool system for reactor auxiliary
308	1980	Hydraulic	Vermont Yankee	1	Leaky turbine connection	CB-Coolant recirc. system
309	1980	Hydraulic	Pilgrim 1	2	Found severed	SF-Emergency core cooling system
310	1980	Hydraulic (7)	Three Mile Is. 1	1	Loss of fluid; leaky seals	WB-Cool system for reactor auxiliary
311	1980	Hydraulic (1)	Brunswick 1	1	Found over extended	
312	1980	Hydraulic (3)	Robinson 2	2	Reservoir fluid leaks	HH-Condensate & feedwater system
313	1980	Hydraulic	Zion 1	2	Did not meet criteria for bleed rates	HB-Main steam supply system
314	1980	Hydraulic	Ft. St. Vrain	9	Hangers were not properly adjusted for hot position	HB-Main steam supply system

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
315	1980	Hydraulic	Oconee 3	1	Loss of fluid; cracked reservoir	SB-Containment heat removal system
316	1980	Hydraulic	Iaten 1	5	Loss of fluid; 2 failed to lockup and 3 had excessive bleed rates	SF-Emergency core cooling system
317	1980	Hydraulic	Pilgrim 1	1	Unknown	SF-Emergency core cooling system
318	1980	Hydraulic	Fitzpatrick	2	Failed test; normal wear	CB-Coolant recirc. system
319	1980	Hydraulic	Oyster Creek	2	Loss of fluid (in valve block) 1 had foreign material in fluid	
320	1980	(Hydraulic)	Oyster Creek	1	Loose socket head screws causes snubber inability to lockup	SF-Emergency core cooling system
321	1980	Hydraulic	Ft. St. Vrain	8	1 empty reservoir, 2 interference problems, and 5 had improper stroke	SF-Emergency core cooling system
322	1980	Hydraulic	Calvert Cliffs	2	Loss of fluid; stripped reservoir tube fittings	SF-Emergency core cooling system
323	1980	Hydraulic	Vermont Yankee	1	Loss of fluid; faulty seals	CC-Main steam system
324	1980	(Hydraulic)	Oconee 2	1	Piston became unscrewed from piston rod eye; vibration	HB-Main steam supply system
325	1980	Hydraulic	Calvert Cliffs	5	Loss of fluid	
326	1980	(Hydraulic)	Oyster Creek	1	Failure to lockup; unknown causes	SB-Containment heat removal
327	1980	Hydraulic)	Surry 2	1	Damage due to improper alignment of pipe clamp to snubber	WH-Condensate & feedwater system
328	1980	Hydraulic	Brunswick 2	1	Loose pipe clamp; vibration	WA-Station service water system
329	1980	(Hydraulic) (3)	Pt. Beach 1	1	Loss of fluid; seal leakage	
330	1980	Hydraulic (1)	Brunswick 1	1	Vibration; excessive wear on piston; failure to lockup	WA-Station service water system
331	1981	Hydraulic	Hillstone 2	1	Fluid reservoir deformed by overheating	H3-Main steam line
332	1981	Hydraulic	Three Mile Is. 1	3	Worn piston ring seals and springs with excessive spring constants	CB-Coolant recirc. system & controls
333	1981	--	Indian Point 3	1	Failure to lock in extension position. Cause not yet determined.	Aux. systems
334	1981	Mechanical	Salem 1	1	Internal corrosion causing seizing of the balls in the race	SF-Emergency core cooling system & cont.
335	1981	Hydraulic	Indian Point 3	1	Low oil level	Aux. systems
336	1981	Hydraulic	Three Mile Is. 1	1	Snapping plug installed in the fluid reservoir vent port- procedure error by contractor	CB-Coolant recirc. system & controls
337	1981	Hydraulic	Zion 1	11	Improper settings and/or excessive seal bypass	EE-System Code not applicable
338	1981	Hydraulic	Parley 1	-	Loss of fluid; cracked fluid reservoir	SB-Containment heat removal system & controls

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339	1981	Hydraulic	Cook 2	2	Leaky O-ring and loose lock nut	ZZ-System code not applicable
340	1981	Hydraulic	Beaver Valley 1		Malfunction of feed regulating valve	HH-Condensate & feedwater system & controls
341	1981	Hydraulic	Crystal River 3	1	Loss of fluid; artificially high readings due to air entrapment	ZZ-System code not applicable
342	1981	Hydraulic	Rancho Seco	3	Low fluid level	CB-Coolant recirc. system & controls
343	1981	Hydraulic	Surry 2	7	Loss of fluid; leaky valves reservoir connections	HH-Condensate & feedwater system & controls
344	1981	Mechanical	San Onofre 1	2	Internal corrosion; improper installation	SF-Emergency core cooling system & controls
345	1981	Hydraulic	North Anna 2	1	Loss of fluid; crack in reservoir tube	CB-Coolant recirc. system & controls
346	1981	Hydraulic	North Anna 1	2	Loose nut; missing stud bolt	HB-Main steam supply system & controls
347	1981	Hydraulic	Salem 1	1	Internal corrosion caused intermittent seizing of the balls in the race	SF-Emergency core cooling system & controls
348	1981	Hydraulic	Rancho Seco	1	Loss of fluid; valve body problems	CB-Coolant recirc. system & controls
349	1981	Hydraulic	Turkey Pt. 4	1	Threaded joint connection failure	HH-Condensate & feedwater system & controls
350	1981	Mechanical	Millstone 2	-	Frozen in place	ZZ-System code not applicable
351	1981	Hydraulic	Palisades	1	Loss of fluid; O-ring failure	SF-Emergency core cooling system & controls
352	1981	Hydraulic	Palisades	1	Loss of fluid; O-ring failure	SF-Emergency core cooling system & controls
353	1981	Hydraulic	Rancho Seco	1	Loss of fluid; leaky valve block seal	PC-Chem. volume cont. & liquid poison system
354	1981	Hydraulic	North Anna 1	1	Heat damage to oil reservoir	CB-Coolant recirc. system & controls
355	1981	Mechanical	Oconee 3	1	Locked; scored ball screw shaft	HH-condensate & feedwater system & controls
356	1981	--	Three Mile Is. 1	-	Improper installation of pipe supports	XX-Other systems
357	1981	--	Millstone 2	15	Fabrication error	XX-Other systems
358	1981	Hydraulic	Cook 1	1	Air in fluid port after installation	ZZ-System code not available
359	1981	Hydraulic	Oconee 2	1	Rod eye broke due to vibration	HB-Main steam supply system & controls
360	1981	Mechanical	Millstone 2	-	Snubbers frozen	XX-Other systems
361	1981	Hydraulic	Crystal River 3	5	Cracked aluminum bushings	ZZ-System code not applicable
362	1981	Hydraulic	Calvert Cliffs 1	1	Loss of fluid; inversion of of snubber due to error	ZZ-System code not applicable
363	1981	Hydraulic	Cook 1	1	Air in fluid inlet port; being pumped by construction personnel	HH-Condensate & feedwater system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
364	1981	Hydraulic	Rancho Seco	1 & 5	Unrestrained; loss of fluid	CS-Other coolant subsys. & control
365	1981	Hydraulic	North Anna 1	1	Loss of fluid; thermal expansion of reach rod	HB-Main steam supply system & controls
366	1981	Hydraulic	Crystal River 3	1,2,3	Bend shaft, cracked, aluminum bushings, excessive bleed rate	ZZ-System code not applicable
367	1981	Hydraulic	San Onofre 1	1	Loss of fluid; failed reservoir seal gasket	CC-Main steam system & controls
368	1981	--	Surry 1	1	Procedural deficiency	HI-Steam generator blowdown system & controls
369	1981	Hydraulic	Surry 2	2	Loss of fluid; leak in mechanical connection on the reservoirs	WB-Cool system for reactor auxiliary & controls
370	1981	Hydraulic	Indian Pt. 2	1	Failure of strut and bolts; water hammer	HI-Steam generator blowdown system & controls
371	1981	Hydraulic	Indian Pt. 2	1	Traverse impact load	CB-Coolant recirc. system & controls
372	1981	--	Surry 1	1	Thermal growth on main steam line prevented full piston compression	HB-Main steam line supply system & control
373	1981	--	Trojan	1	Maintenance personnel error system & controls	EE-Emergency generator
374	1981	Hydraulic	Cook 2	1	Nut fell off due to vibration	ZZ-System code not applicable
375	1981	Mechanical	Millstone 2	-	Several generic problem areas	ZZ-System code not applicable
376	1981	--	Crystal River 3	1	Design error	ZZ-System code not applicable
377	1981	Hydraulic	Indian Pt. 3	1	Scored poppets allowed high bleed rate	XX-Other systems
378	1981	Hydraulic	Indian Pt. 3	1	Loss of fluid; O-ring failure	XX-Other systems
379	1981	Hydraulic	Pallicades	6	O-ring seal failure	XX-Other systems
380	1981	--	Oconee 1	6	High temperature conditions affected settings	HH-Condensate & feedwater system & controls
381	1981	Hydraulic	North Anna 2	1	Loss of fluid; scored bushing on piston shaft	HB-Main steam supply system & controls
382	1981	Hydraulic	Parley 2	1	Loss of fluid; cracked fluid reservoir	XX-Other systems
383	1981	Hydraulic	St. Lucie 1	3	Grease contamination; maintenance personnel error	SF-Emergency core cooling system & controls
384	1981	Hydraulic	Crystal River 3	75	Debris in hydraulic fluid; air entrapment through snubber seals; use of untempered radial bearings	ZZ- Auxiliary system
385	1981	Hydraulic	North Anna 2	1	Loss of fluid	HB-Main steam supply system & controls
386	1981	Hydraulic	Dresden 2	4	Environmental conditions in the drywell that promote fluid leakage and snubber degradation	CB-Coolant recirc. system & controls
387	1981	Hydraulic	Cooper	1	Reservoir connecting pipe improperly installed	SF-Emergency core cooling system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
388	1981	Hydraulic	Oyster Creek	1	Deteriorated inner shaft seal	SB-Containment heat removal system & controls
389	1981	--	Brunswick 1	1	Water hammer; snubber overload	CF-Residual heat removal system & controls
390	1981	--	Brunswick 1	2	Water hammer; snubber overload	SF-Emergency core cooling system & controls
391	1981	Hydraulic	Peach Bottom 2	4	Piston seal deterioration	ZZ-System code not applicable
392	1981	Hydraulic	Dresden 3	2	Environmental conditions in pipeway which promote fluid leakage and snubber degradation	SH-Other engineered safety feature systems
393	1981	Hydraulic	Brunswick 2	130	Worn poppets; low poppet resistance to pipe vibrations	XX-Other systems
394	1981	Hydraulic	Hatch 2	2	Lower seal leak; incorrect closing speed	CD-Main steam isolation system & controls
395	1981	Hydraulic	Vermont Yankee	1	Seal leakage	CC-Main steam
396	1981	Mechanical	Cooper	2	Unknown	CB-Coolant recirc. system & controls
397	1981	Hydraulic	Ferry 1	1	Leaky thread connection	CB-Coolant recirc. system & controls
398	1981	Hydraulic	Hatch 1	4	Seal leakage	SF-Emergency core cooling system & controls
399	1981	--	Fitzpatrick	1	Plugged with rust	SD-Containment isolation system & controls
400	1981	Hydraulic	Brunswick 2	1	Unscrewed from mounting paddle; vibration	VA-Station service water system & controls
401	1981	--	Brunswick 1	1	Incorrect installation; construction personnel error	SF-Emergency core cooling system & controls
402	1981	Hydraulic	Brunswick 1	1	Incorrect installation; construction personnel error	SF-Emergency core cooling system & controls
403	1981	Hydraulic	Oyster Creek	3	Dirty oil; cracked head ring; faulty seals	CF-Residual heat removal system & controls
404	1981	Hydraulic	Brunswick 2	1	Piping vibration dislodged connecting pin	VA-Station service water system & controls
405	1981	Mechanical	Fitzpatrick	1	Improper installation	CC-Main steam system & controls
406	1981	Hydraulic	3 Mile Pt. 1	1	Seal leakage	CH-Feedwater system & controls
407	1981	Mechanical	Hatch 2	2	Dent adjacent hanger	SF-Emergency core cooling system & controls
408	1981	Hydraulic	Peach Bottom 3	-	Failed locking velocity	SH-Other engineered safety feature system
409	1981	Hydraulic	Pt. St. Vrain	1	Leaky elbow fitting	ZZ-System code not applicable
410	1981	Hydraulic	Pt. St. Vrain	3	Leaky seals and O-rings	ZZ-System code not applicable
411	1981	Hydraulic	Oyster Creek	11	Oil leakage	XX-Other systems
412	1981	Hydraulic	Pt. St. Vrain	1	Leak valve; leaky piston	ZZ-System code not applicable
413	1981	--	Pt. St. Vrain	1 & 2	Thermal growth; welding of support steel	HB-Main steam supply system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
414	1981	--	Ft. St. Vrain	1	Detached; cotter pin failure	HB-Main steam supply system & controls
415	1982	Hydraulic	Hatch 1	4	Pedestal concrete outer wall showed spalling and surface cracks	CB-Coolant recirc. system & controls
416	1982	Hydraulic	Oyster Creek	3	Component failure	Auxiliary systems
417	1982	--	Arnold	2	Water hammer; overloaded snubber	CF-Residual heat removal system & controls
418	1982	--	Arnold	1	Degraded concrete expansion bolts	SF-Emergency core cooling system & controls
419	1982	Mechanical	Big Rock Pt.	1	Acceleration test failure; cause unknown	SH-Other engineered safety feature system
420	1982	--	Fitzpatrick	2	Damaged; cause unknown	CF-Residual heat removal system & controls
421	1982	--	Fitzpatrick	1	Improper instrument line snubber setting, procedural error	SF-Emergency core cooling system & controls
422	1982	Mechanical	Dresden 3	1	Overloading	CG-Reactor coolant clean up system & controls
423	1982	Mechanical	Cooper	1	Improper installation	CC-Main steam systems & controls
424	1982	Hydraulic	Peach Bottom 3	2	Loss of fluid; seal leakage	ZZ-System code not applicable
425	1982	Hydraulic	Brunswick 2	1	Base plate for snubber support base missing 3 of 4 nuts of wedge anchor, 4th wedge anchor missing - construction personnel error	CA-Reactor vessel & appurtenances
426	1982	Mechanical	Cooper 2	2	Overloading	CB-Coolant recirc. system & controls
427	1982	Mechanical	LaSalle 1	1	Bent drive mechanism	CB-Coolant recirc. system & controls
428	1982	Hydraulic	Browns Ferry 2	1	Leaky fittings and seals	CB-Coolant recirc. system & controls
429	1982	--	LaSalle 1	1	Improper installation; maintenance personnel error	CF-Residual heat removal system & controls
430	1982	Mechanical	LaSalle 1	1	Excessive force in lateral direction	XX-Other systems
431	1982	Hydraulic	Oyster Creek	7	Seal degradation; worn poppet valves	SF-Emergency core cooling system & controls
432	1982	Hydraulic	Millstone 1	1	Loss of fluid; cracked reservoir glass	ZZ-System code not applicable
433	1982	Mechanical	LaSalle 1	1	Missing load pin	CF-Residual heat removal system & controls
434	1982	Mechanical	Browns Ferry 2	1	Locked up	CC-Main steam system & controls
435	1982	Hydraulic	Hatch 1	1	Worn piston rod seal	CF-Residual heat removal system & controls
436	1982	Hydraulic	Browns Ferry 2	1	Oil leak	CB-Coolant recirc. system & controls
437	1982	--	Cooper	1	Inverted; licensed operator error	SF-Emergency core cooling system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
438	1982	Hydraulic	Peach Bottom 2	2	Unknown; improper installation	SF-Emergency core cooling system & controls
439	1982	Hydraulic	Arnold	1	Loss of fluid	CF-Residual heat removal system & controls
440	1982	Hydraulic	Ft. St. Vrain	13	Seal leaks, oil level, piston position	HB-Main steam supply system & controls
441	1982	Hydraulic	Ft. St. Vrain	5 & 4	Mechanical adjustments; block valve repair	HB-Main steam supply system & controls
442	1982	Hydraulic	Ft. St. Vrain	1	Oil leak; seal and gasket	XX-Other systems
443	1982	Hydraulic	Ft. St. Vrain	10	Lack of oil, full compression, improper reservoir orientation	HB-Main steam supply system & controls
444	1982	Hydraulic	Ft. St. Vrain	5	Thermal expansion	AD-Other auxiliary systems & controls
445	1982	Hydraulic	Ft. St. Vrain	8	Pipe movement; seal leakage	HB-Main steam supply system & controls
446	1982	Mechanical	St. Lucie 1	1	Unknown	CJ-Other coolant subsystem & control
447	1982	Mechanical	Sequoyah 1	3	Improper installation and corrosion	ZZ-System code not applicable
448	1982	Hydraulic	Palisades	1	Loss of fluid; O-ring deterioration	CF-Emergency core cooling system & controls
449	1982	Hydraulic	Rancho Seco	2	Loss of fluid	CJ-Other coolant subsystem & control
450	1982	Hydraulic	Surry 1	3	Seal leakage	HB-Steam Supply system & controls
451	1982	Hydraulic	Zion 1	1	Seal leak	SI-Steam generator blowdown system & controls
452	1982	Hydraulic	Crystal River 3	1	Leaky shaft seal	ZZ-System code not applicable
453	1982	Hydraulic	Surry 2	1	Seal leakage	SF-Emergency core cooling system & controls
454	1982	--	Salem 2	2	Seize; cause unknown	CH-Feedwater system & controls
455	1982	Hydraulic	Farley 2	1	Loss of fluid; improperly	HB-Main steam supply system & controls
456	1982	Hydraulic	San Onofre 1	5	Abnormal wear	CH-Feedwater system & controls
457	1982	Mechanical	Sequoyah 2	3	Bend assemblies; installation errors	CB-Coolant recirc. system & controls
458	1982	--	Salem 2	2	Seized; cause unknown	CH-Condensate & feedwater system & controls
459	1982	--	St. Lucie 1	3	Unknown	CJ-Other coolant subsystem & control
460	1982	Hydraulic	Turkey Pt. 3	-	Hydraulic shock of opening isolation valve	HI-Steam generator blowdown system & controls
461	1982	Hydraulic	Surry 2	2	Damaged O-ring; loose fitting	CB-Coolant recirc. system & controls
462	1982	Hydraulic	Palisades	1	Deteriorated O-rings	HB-Main steam supply system & controls
463	1982	Hydraulic	Palisades	2	Deteriorated O-rings	SF-Emergency core cooling system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
464	1982	Hydraulic	Surry 2	1	Improperly installed rod seal	HB-Main steam supply system & controls
465	1982	Mechanical	Trojan	1	Disconnected; personnel error & control	CJ-Other coolant subsystem
466	1982	Hydraulic	Palisades	1	O-ring deterioration	CF-Residual heat removal system & controls
467	1982	Hydraulic	Maine Yankee	1	Loss of fluid through ethylene propylene cylinder seal and snubber valve fitting	HB-Main steam supply system & controls
468	1982	--	Surry 1	1	Missing cotter pins	CC-Main steam systems & controls
469	1982	Hydraulic	Palisades	1	Loss of fluid; scored cylinder wall due to vibration	CF-Residual heat removal system & controls
470	1982	--	Oconee 3	1	Installation deficiency	HH-Condensate & feedwater system & controls
471	1982	Mechanical	Surry 1	1	Mechanical pin missing	CH-Feedwater systems & controls
472	1982	Hydraulic	Surry 1	4	Loss of fluid	CH-Feedwater systems & controls
473	1982	Hydraulic	Surry 1	1	Reservoir tubing cut; maintenance personnel error	CC-Main steam systems & controls
474	1982	--	Maine Yankee	1	Improper rod end installation	SF-Emergency core cooling system & controls
475	1982	Hydraulic	Indian Pt. 2	3	Failed lockup and bleed rate cause unknown	XX-Other systems
476	1982	Hydraulic	Millstone 2	1	Broken snubber stud; high vibration level	HB-Main steam supply system & controls
477	1982	Hydraulic	Salem 1	10	Failed bleed test; cause unknown	HB-Main steam supply system & controls
478	1982	Hydraulic	Farley 2	1	O-ring leak; installation error	CB-Coolant recirc. system & controls
479	1982	Hydraulic	Point Beach 1	1	Damaged shaft seal	HB-Main steam supply system & controls
480	1982	Hydraulic	Dalvert Cliffs 1	1	Leaky oil seal	ZZ-System code not applicable
481	1982	Hydraulic	Surry 2	4	Leak on reservoir sight glass; leak on pipe fitting to the valve block; leak in tubing connection	CB-Coolant recirc. system & coolant
482	1982	--	San Onofre 2	2	Damaged; cause unknown	HH-Condensate & feedwater system & controls
483	1982	Hydraulic	Rancho Seco	1	Loss of fluid	CB-Coolant Recirc. system & controls
484	1982	--	San Onofre 2	5	Water hammer - snubber overload	HH-Condensate & feedwater system & controls
485	1982	Hydraulic	Maine Yankee	1	Seal leakage	HB-Main steam supply system & controls
486	1983	Hydraulic	Palisades	1	Loss of fluid	SF-Emergency core cooling system & controls
487	1983	Hydraulic	Salem 2	2	Piston seal rubber flattened; age	CB-Coolant recirc. system & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
488	1983	Hydraulic	Gienna	1	Detached piston rod	HB-Main steam supply system & controls
489	1983	Hydraulic	Surry 2	1	Loss of fluid; loose packing nut	CC-Main steam systems & controls
490	1983	Hydraulic	Surry 1	5	Loss of fluid; loose pipe clamp; tilted valve block	ZZ-System code not applicable
491	1983	Hydraulic	Surry 1	11	Seal degradation; fail to meet tech. spec.	ZZ-System code not applicable
492	1983	Mechanical	Surry 1	9	Failed to meet tech. spec. requirement	ZZ-System code not applicable
493	1983	--	San Onofre 3	-	Loose sampling valves	CJ-Other coolant subsystem & control
494	1983	Hydraulic	Millstone 2	1	Fluid loss; seal degradation due to vibration of main steam line	HB-Main steam supply system & controls
495	1983	Hydraulic	Oconee 1	1	Rotated; procedural error	HS-Other feat/steam & power conv. system
496	1983	Mechanical	Salem 2	4	Failed to meet tech. spec. requirement	SE-Emergency core cooling system & controls
497	1983	Mechanical	McGuire 1	2	Locked up; water hammer	CF-Residual heat removal system & controls
498	1983	Hydraulic	North Anna 2	1	Loss of fluid; reservoir damaged by personnel	HI-3-steam generator blowdown system & controls
499	1983	Hydraulic	Zion 2	3	Leaky seals	XX-Other systems
500	1983	Hydraulic	3 Mile Island 1	1	Damaged piston seal-ring installed backward	ZZ-System code not applicable
501	1983	Hydraulic	Dalvert "Cliffs"	1	Reservoir damaged by heat from uninsulated adjacent piping	ZZ-System code not applicable
502	1983	Mechanical	San Onofre 3	1	Partial disengagement of the rod end	SB-Containment heat removal system & controls
503	1983	Hydraulic	Crystal River 3	-	Seal failure; valve assembly contamination	XX-Other systems
504	1983	Hydraulic	Rancho Seco	10	Poppet seal scored; defective seals; corrosion in body; water in fluid	XX-Other systems
505	1983	--	Tukey Pt. 1	1	Modification to attachment was not complete; personnel	SB-Containment heat removal system & controls
506	1983	--	Summer 1	1	Misalignment; bent paddle plate	WB-Cool sys. for reactor auxiliary & controls
507	1983	--	Summer 1	1	Bearing protrusion from paddle plate; vibration	CF-Residual heat removal system & controls
508	1983	--	Summer 1	1	Bearing offset	CF-Feedwater system & controls
509	1983	Hydraulic	Oconee 2	1	Component failure and personnel error	HS-Other feat. steam & power conv. system
510	1983	Hydraulic	Surry 2	23	Seal degradation; scored piston/body	XX-Other systems
511	1983	Hydraulic	Davis-Besse 1	1	Loss of fluid	CC-Main steam system & controls
512	1983	--	Summer 1	1	Out of alignment	WB-Cool sys. for reactor auxiliary & controls

No.	Year	Snubber Type & Manufacturer	Facility	Number of Snubbers	Description of Failure	System
513	1983	Hydraulic	Palisades	1	Failed to lockup	XX-Other systems
514	1983	--	Diablo Canyon	45	Micro-cracks in the capstan spring tangs	ZZ-System code not applicable
515	1983	Hydraulic	Surry 1	5	Loss of fluid; fitting leak	HB-Main steam supply system & controls
516	1983	Hydraulic	Ft. St. Vrain	4 & 1	Leaky seals; broken reservoir	HB-Main steam supply system & controls
517	1983	Hydraulic	Ft. St. Vrain	2	Thermal pipe movement	HB-Main steam supply system & controls
518	1983	Hydraulic	Fitzpatrick	1	Failure to lockup	CG-Reac. cool clean up system & controls
519	1983	Mechanical	Big Rock Pt.	1	Failure to meet drag force criteria	SH-Other engineered safety featr. system
520	1983	Hydraulic	Hatch 1	1	Loss of fluid	CD-Main steam ISOL system & controls
521	1983	--	LaSalle 1	1	Rear bracket pin missing	XX-Other systems
522	1983	Mechanical	Dresden 2	5	Dynamic overload	CC-Main steam system & controls
523	1983	Mechanical	Dresden 2	2	Pipe clamp bolt and nut loose; installation error	CC-Main steam system & controls
524	1983	--	Dresden 3	1	Plugged	SF-Emergency core cooling system & controls
525	1983	Mechanical	Dresden 3	1	Unattached; installation error	SA-Reactor containment system
526	1983	Mechanical	Dresden 2	2	Unknown	CC-Main steam system & controls
527	1983	--	Arnold	2	Bushing missing; bushing disengaged	CJ-Other coolant subsystem & controls
528	1983	Hydraulic	Arnold	8	Seal deterioration/wear and improper installation instructions	SF-Emergency core cooling system & controls
529	1983	Mechanical	LaSalle 1	1	Hard to stroke	CC-Main steam system & controls
530	1983	Mechanical	Cooper	4	Frozen; water hammer overload	CF-Residual heat removal system & controls
531	1983	Mechanical	LaSalle 1	1	Locked	CE-Reac. core isol. cool. system & controls
532	1983	Mechanical	LaSalle 1	1	Locked	XX-Other systems
533	1983	Mechanical	Dresden 2	1	Pipe clamp loose	CC-Main steam system & controls
534	1983	Hydraulic	Cooper	2	Failed bleed rate; lockup rate; both foreign material plugging bleed screw and lockup valve	CC-Main steam system & controls

KEY:

MANUFACTURING COMPANIES:

- (1) Bergen-Patterson
- (2) Anker-Holth
- (3) Grinnel
- (4) Power Piping Co.
- (5) Blaw Knox
- (6) Nuclear Safeguards Corporation
- (7) Basic Eng.
- (8) Pacific Scientific

SOME FAILURE RESULTS

- (1) Snubber locked or out of restraint tolerance.
- (2) Snubber will not lock in service when subjected to dynamic loads.
- (3) Piping over load due to pressure transient.

Figure F-1. Reported Snubber Failure Incidents 1973-1983

Table F-1
ESTIMATED SNUBBER POPULATION FOR NUCLEAR POWER PLANTS

Year of Commercial Operation	Snubbers		Total
	Hydraulic	Mechanical	
1973	7500	800	8,300
1974	8500	1000	9,500
1975	11260	1920	12,180
1976	14020	2840	16,860
1977	16780	4300	21,080
1978	19540	5750	25,290
1979	22300	7170	29,470
1980	23570	9880	33,450
1981	24840	12590	37,430
1982	26110	15300	41,410
1983	27380	18010	45,350

Based on:

1957-1974	45 units @	190 hydraulic;	22 mechanical per plant
1975-1979	23 units @	600 hydraulic;	270 mechanical per plant
1980-1983	13 units @	390 hydraulic;	835 mechanical per plant

Note: Estimates are based on incomplete information. A detailed survey of snubbers contained in operating plants should be undertaken to accurately quantify snubber population.

Figure F-2. Estimate of Snubber Population in Nuclear Power Plants and Normalized Failure Rates

APPENDIX G
REPORT ON FOREIGN PRACTICE

Introduction

This appendix summarizes the response of several non-U.S. organizations regarding the current practices used in the design of nuclear power plant piping subjected to seismic (earthquake) loading. The material was developed as a result of responses to a questionnaire sent to several foreign agencies, both government and industry, in December 1983. The questionnaire was comprehensive with regard to general piping design; hence, it included requests for information beyond the scope of seismic design.

In addition, information discussions were held at several of the organizations in January 1984. The following organizations have responded to the questionnaire, or individuals from these organizations have discussed the questionnaire:

1. Belgium--
Electrobel
Tractionel
2. Canada--
Ontario Hydro
Atomic Energy of Canada, Ltd., AECL
3. France--
Framatome
French Electricity Authority, EDF
French Atomic Energy Commission, CEA
4. Italy--
Ansaldo Impianti
5. Japan--
"Procedures, Analysis and Research on Earthquake-Resistant Design for Nuclear Power Plants," presented at the Tadotsu Users' Seminar, TADOTSU, Japan, May 1983.
6. Sweden--
Swedish Nuclear Power Inspectorate. The responses in this paper are specific to the Forsmark 3 and Oskarshamn 3 stations.
7. Federal Republic of Germany--
Kraftwerk Union, KWU
Technischer Ueberwachungs-Verein, TUV Rheinland
Company for Reactor Safety, GRS

The positions taken are summarized by topic areas and by country. The country positions are a composite of the information received. This information was transmitted to the contributing organizations for their review comments and

corrected as necessary. Information in this appendix is unofficial and does not necessarily reflect formal regulatory policy.

Considerable detailed background information on seismic design of nuclear power plant facilities in several foreign countries is also contained in NUREG/CR-3020 [Ref. G-1]. This reference can be used in conjunction with this appendix to provide a more comprehensive picture. The text of this appendix is based in part on translated material provided by the contributing organizations; hence, the English may seem stilted.

Seismic Load

1. Load Definition Applicable to Piping

a. Belgium

Any type of seismic load definition is "permissible" to the Belgian Safety Authorities (BSA) as long as its adequacy can be demonstrated or justified. The following rules are accepted without further justification:

- Floor response spectra compatible with Regulatory Guide 1.60 ground spectra when generated by time-history or direct methods;
- Quasistatic analysis of the piping system with a 1.5 amplification coefficient applied to the peak of the floor response spectrum;
- Time-history dynamic analysis (uncommon).

b. Canada

Safety-related piping is qualified by dynamic analysis only. Floor response spectra using dynamic multidegree-of-freedom analysis is most commonly used. When analysis is done by the Equivalent Static Load Method, a multiple of 1.5 times the peak of the floor spectra applied to the mass distribution of the piping is used. The factor of 1.5 is applied to simulate multifrequency excitation and multimode response. This method has been used for non-safety-related small-diameter (less than 6" nominal size) cold piping systems that are field-run and/or field-hung. The only other form of seismic load definitions consists of a real time-history, acceleration vs. time.

c. France

The practice is to use floor or amplified response spectra using dynamic multidegree-of-freedom analysis. For small piping with temperature below about 100°C, simplified dynamic and static analysis are performed to generate tables and nomographs.

d. Italy

Floor response spectra using dynamic multidegree-of-freedom analysis is used. A multiplier of 1.5 times the peak of the floor response spectra applied to the mass distribution of the pipe may also be used. Another form of seismic load permitted is a multiple of the acceleration corresponding to the first frequency of the piping system applied to its mass.

e. Japan

Floor response spectra using dynamic multidegree-of-freedom analysis is used. In addition to this, a static coefficient closely related to building design must be applied. However, the result of the static coefficient method, which is 1.2 times the seismic (static) coefficient at the floor, is usually lower than the result of dynamic analysis at most of the plants, and this is not wholly applicable.

f. Sweden

Floor response spectra using multidegree-of-freedom analysis is required as a loading input when seismic design loads are specified for the plant.

g. Federal Republic of Germany

Seismic load definitions applicable to piping are identified as follows:

- (1) Ground spectra are used for safety-related components that are underground, e.g., the piping for the secondary cooling water system or cable ducts. For buried lines close to buildings, the effect of the buildings is considered in the spectra input to the buried lines. In buildings, floor response spectra are used.
- (2) Dynamic analysis of piping is performed according to the response spectra procedure (modal analysis) with the use of enveloping spectra. Attention is paid in the use of spectra to which points accelerations of the building are transmitted to the piping. It is generally assumed that for each of these points a different spectrum is applied. In practice, however, in the case of horizontal spectra, a difference is made only for the vertical height, i.e., the same spectrum applies to various points at the same vertical height of a building. In addition, we are of the opinion that, in the case of uneven support point excitation, the multispectral technique, i.e., the weighted spectra method, is to be preferred to the simple response spectrum method (which by way of substitution employs an envelope spectrum).

In case a piping runs through several floors or through several buildings, the individual floor response spectra of an excitation direction can be combined into an enveloping spectrum.

- (3) A piping system can also be calculated with an equivalent static load. This calculation differs from the dynamic calculation inasmuch as a determination of the inherent frequencies and shapes can be omitted. A simplification of computer model is generally not connected therewith. Calculations with a single peak spectral value of the response spectrum are not made.
- (4) The dynamic stress in the three main directions is substituted with a constant line load, which results from the multiplication (mass) x (peak spectral value) x V.

Generally, the factor V has the value of 1.5. This does not apply when the fundamental frequency lies in the rigid-body range of the spectrum.

Other definitions for seismic loads are not admissible for nuclear facilities. See KTA Rule 2201.4 for definitive requirements.

2. Directional Input and Magnitude for Seismic Loads on Piping

a. Belgium

Two horizontal and one vertical component of earthquake are considered consistent with the requirement of USNRC Regulatory Guide 1.92.

b. Canada

The directions of seismic loading considered are two horizontal plus one vertical. The three directions of seismic loading are considered simultaneously. The design ground motions in the horizontal directions are assumed equal. When no specific data are available for obtaining the vertical direction ground motion, it is assumed to be two-thirds of that in the horizontal direction (CAN3-N289.3-M81, Sections 3.2.4 and 3.2.5).

c. France

Three directions of seismic loading are considered simultaneously (two horizontal and one vertical).

The three components of ground response spectra are considered independent. The two horizontal components are of equal magnitude and the vertical component is two-thirds of the horizontal; floor response spectra are computed from ground motions using building response analysis.

d. Italy

Two horizontal and one vertical component of earthquake motion are considered consistent with the requirement of USNRC Regulatory Guide 1.92.

e. Japan

One horizontal plus one vertical component of earthquake are applied to the piping. The horizontal component is based on the limiting dynamic (response spectra) or a static coefficient. The vertical component is based on the limiting static coefficient. In cases where the building has a torsional response, two horizontal components are applied to the piping.

f. Sweden

Two independent horizontal and one vertical component of earthquake motion are considered. Horizontal components are of equal magnitude. The vertical is taken as two-thirds of the horizontal component in magnitude.

g. Federal Republic of Germany

One horizontal plus one vertical component of simultaneous earthquake motion are typically applied to the design of the piping. In general, two analyses are performed. A nominal N-S and vertical component are considered and then separately a nominal E-W and vertical component are considered and the worst

case used for piping design. Alternatively, the horizontal components may be aligned with the major axes of the piping system instead of in a nominal N-S or E-W direction. The maximum vertical component of earthquake motion is taken equal to one-half the maximum horizontal magnitude.

3. Potential Use of Inelastic Spectra in Piping Design

a. Belgium

Use of inelastic floor response spectra would probably be permitted if justified. No such request has been made to the Belgium Safety Authorities.

b. Canada

Inelastic floor spectral input has not been used nor is it contemplated for use at this time.

c. France

Inelastic floor response spectra are not used.

d. Italy

Inelastic floor spectra have not been used for seismic loads but have been used in association with aircraft impact (SEC condition). In those instances, global ductility factors of 2 or 3 have been used.

e. Japan

Inelastic spectra have not been used nor is any application expected.

f. Sweden

Inelastic effects are not considered.

g. Federal Republic of Germany

Plastic or inelastic floor response spectra are not used in Germany for the earthquake loading case. According to KTA Rule 2201.1, plant components of Class 1 systems have to be designed in such a manner that they will be capable of withstanding the seismically induced stresses of the applicable earthquake together with other stresses (e.g., deadweight, constant load, operating loads, forces, and moment caused by temperature) within the elastic limits or within the limits corresponding to those admitted by standards to such an extent that their subsequent operation is possible even after a repeated occurrence of this earthquake.

There has been some limited application of inelastic spectra to air duct design using a ductility coefficient of 3.0.

Discussions are being held between industry and the German regulatory authorities concerning the possible use of a strain-based criterion with limits up to 2.0% strain in the future.

4. Earthquake Levels Considered in Design of Piping

a. Belgium

Both OBE and SSE earthquake levels are considered for safety-related piping systems. For nonsafety piping (that which may interact with safety-related equipment), the SSE is the only earthquake level considered. When the OBE is used, it always controls the design.

b. Canada

The Canadian seismic design philosophy is much different from that used in the U.S. where both OBE and SSE are defined for a given Seismic Category I piping system. In Canada, either the design basis earthquake (DBE) or the site design earthquake (SDE) levels are defined in design of a particular piping system but not both.

To provide assurance of critical systems performing their safety-related functions in the event of an earthquake, selected safety-related systems in the nuclear power plant are designed to the specific earthquake levels considered in design and defined as follows:

(1) Design Basis Earthquake

The DBE for a plant is defined as an artificial representation of the combined effects in the free-field at the site of a set of possible earthquakes having a sufficiently low probability of exceedance during the life of the plant, expressed in the form of response spectra or a time-history.

(2) Site Design Earthquake

The SDE for a plant is defined as the maximum predicted effect in the free-field at the site, having an occurrence rate of 0.01 per year, based on historical records of actual earthquakes applicable to the site, expressed in the form of response spectra or a time-history. The SDE shall have a peak ground motion acceleration not less than 0.03g.

The DBE and SDE for the plant are specified by a peak horizontal ground acceleration value, as well as the design ground response spectrum or time-history. The peak ground acceleration values for the DBE and SDE are determined from a study of site seismicity based on an examination of historical and instrumented earthquake records for the area, as well as the seismotectonics of the surrounding geological structure.

The applicable design earthquake is treated as an extreme environmental load having a low probability of exceedance. Only one design earthquake as applicable is assumed to occur during the life of the plant.

For more information on the Canadian seismic design philosophy, refer to Canadian Standards Association Standard CAN3-N289.3-M81.

c. France

To establish the safety level earthquake, SMS, the historical seismicity of the region is studied, and the epicenters of the highest events are moved as near as possible to the site, from seismotectonical considerations. The corresponding maximum intensity earthquake at the site, SMHV, as defined in the MSK intensity scale, is estimated. The SMS intensity is taken as SMHV + 1. A response spectrum for the site is deduced from statistical analysis of recorded earthquakes with representative magnitude and epicenter distance characteristics. For the SMS-level earthquake, safe shutdown is required.

A lower-level earthquake, often called the SNA, is also established. It is generally fixed at (SMS-1) intensity level, which typically means a half level for acceleration. It is not in principle required by safety authorities and in general does not control design. In the past, only single envelope spectra were considered. Recently, several response spectra located at different supports and nozzle points have been used; in order to minimize the effect of response spectra amplified by equipment or primary piping, a multiple excitation response technique is used which is presented in a book soon to be published.

d. Italy

Two levels of earthquake are defined, OBE and SSE. The OBE generally controls design of piping.

e. Japan

Both S_1 and S_2 earthquakes are considered for safety class A_2 (in most cases) or A_s piping. For safety class A_1 (in most cases) or A piping, only the S_1 earthquake is considered. For earthquake and safety classification of Japanese nuclear plant piping, see Reference G-2.

It is difficult to determine the level of earthquake that controls the design of piping. In the past, piping design has been controlled by the S_2 earthquake in general because the seismic input ratio of S_2 to S_1 is greater than the piping and support allowable stress ratio of S_2 to S_1 and based on the Japanese practice of using the same damping values and an elastic design basis. But, recently and in the future, floor response spectra may be developed using analytical methods that consider damping as a function of load level resulting in the relative decrease of the S_2 floor response spectra such that the S_1 may control design.

f. Sweden

The SSE, when used, controls design. The OBE for Swedish low-seismic site conditions is effectively zero.

g. Federal Republic of Germany

All Class 1 plant components, according to KTA Rule 2201.1, are designed in such a manner that even after a repeated occurrence of a design (base) earthquake, their subsequent operation is possible, and their operability is maintained after a one-time occurrence of a safe shutdown (also, maximum potential) earthquake.

The design (base) earthquake, DBE, is the earthquake with the highest intensity at the site that occurred in the past taking into consideration the close proximity of the site (in the same seismotectonic unit up to a distance of about 50 km from the site).

The DBE is limiting for the design of the piping systems on account of the required lower allowable stresses.

It had been intended for the new Konvoy series of plants that piping design would be evaluated only against the SSE-level earthquake. However, because of complications with the seismic design of building structures, piping is still being evaluated for both the OBE and SSE levels of earthquake. For Seismic Class 2 piping (e.g., fire lines), the SSE with only an equivalent static load method (spacing tables and charts) is normally used for design.

5. Piping System Differential Support Motion

a. Belgium

A single-envelope-support excitation is usually used. Envelope spectra are developed from floor response spectra broadened as per USNRC Regulatory Guides 1.92 and 1.122.

When multiple-support excitation is used, absolute sum of the contributions of the different support locations is performed at the modal level; modal and directional contributions are then summed as per USNRC Regulatory Guide 1.92.

b. Canada

Both single-envelope spectra and multiple-support-points spectra inputs are used. Envelope spectra are developed by taking the highest numerical value of the acceleration of all the support spectra at all frequencies. For an example of details on the multiple-support excitation method, see Reference G-3.

The sequence of support motion combination is as follows:

Various groups from multisupport excitation are combined:

-SRSS if the response between groups are independent of each other (the most common occurrence).

-Absolute if maximum responses occur at the same time.

While Ontario Hydro uses an inhouse program, Atomic Energy of Canada, Ltd. (AECL), the nuclear steam system designer, uses NUPIPE II Computer Code to do piping analysis using multiple-support excitation.

c. France

Envelope spectra have been used in the past. On the new 1400 MWe N-4 series of plants, it is expected that individual support motions will be considered. In such cases, relative support motions will be combined on a square root sum of squares (SRSS) basis.

d. Italy

Envelope spectra (umbrella of all spectra involved in the piping system) have been used to date.

e. Japan

A single-envelope spectrum is used. This spectrum is developed by enveloping applicable spectra for the pipe line to be analyzed. Relative displacement between buildings where the pipe line is installed have in some cases been considered in design.

f. Sweden

A single-envelope spectrum is used.

g. Federal Republic of Germany

In theory, a different spectrum is used for each support point. In practice, however, in the case of horizontal spectra, a difference is made only for the vertical height, i.e., the same spectrum applies to different points on the vertical height of a building. In case a pipe runs through several floors or several buildings, the individual floor response spectra of an excitation response spectrum can be comprised into an enveloping spectrum.

In instances where a single-envelope spectrum used seismic anchor motions, SAMs are not considered. When several differential support motion spectra are used, the resultant combination of support motions is on an SRSS basis.

6. Basis and Values of Damping Used in Piping Design

a. Belgium

USNRC Regulatory Guide 1.61 values are used.

b. Canada

The only kind of damping considered, in the general practice of piping analysis, is a function of pipe size. For values of percent critical damping used in design, refer to Canadian Standards Association Standard CAN3-N289.3-M81. The designers may opt for computation of composite modal damping (see CAN3-N289.3-M81). Generally, specific damping for pipe supports has been ignored, but this conservatism will be removed in the near future.

c. France

For all French plants, a value of 2% of critical damping is used for SNA and SMS for all auxiliary and secondary piping of all diameters. Damping is thus considered independent of frequency, of mode, and of support type.

d. Italy

USNRC Regulatory Guide 1.61 values are used.

e. Japan

Although the damping factor of a piping system has not been specified as official design criteria in Japan, 0.5% has been used as design practice. However, the damping factor has been recently reviewed resulting in an increase in the range from 0.5 to 2.5% as a function of support type and numbers, thermal insulation, deflection, and amplitude of motion.

f. Sweden

USNRC Regulatory Guide 1.61 damping values are used.

g. Federal Republic of Germany

The following values of damping are used for piping:

Components	Values of Damping	
	Design Earthquake	Safe Shutdown Earthquake
Piping with diameters greater than or equal to 300 mm	2%	3%
Piping with diameters smaller than 300 mm	1%	2%
Welded steel structures	2%	4%
Screwed-on steel structures	4%	7%
Screwed-on steel structures with GV connections	2%	4%
Cable bearer constructions	-	10%

7. Spacial and Modal Combination of Earthquake Motions

a. Belgium

USNRC Regulatory Guide 1.92 methods are used. Modes are combined before directions.

b. Canada

Modal combinations are as per CAN3-N289.3-M81 (Sections 5.11 and 5.17). After modes are combined, directions are combined as per CAN3-N289.3-M81 (Section 5.7).

c. France

The combination is performed first on mode and then on direction by SRSS method. For the mode combination of closely spaced modes, the absolute sum is used.

d. Italy

USNRC Regulatory Guide 1.92 methods are used. Modes are combined before directions.

e. Japan

Modal components are combined by SRSS, including closely spaced modes. Spatial components when developed from dynamic analysis are combined by SRSS, but conservatively by absolute sum at stress level when the vertical component is defined as static coefficient. For the sequence of load combination, mode is considered first and then direction. This combination was made on the acceleration level for most old plants but in more recent designs the combination is performed on internal force, moment, or stress levels.

f. Federal Republic of Germany

In the combination of the individual mode shapes, the maximum values (e.g., sectional magnitudes, accelerations, stresses) are used for an excitation direction. The combination is performed according to the equation

$$S = \left[\sum_{i=1}^m S_i^2 \right]^{1/2}$$

where

S = the resulting maximum magnitude for an excitation direction

S_i = the maximum magnitude of the i th inherent shape for the considered excitation direction

m = number of the frequencies to be considered up to the upper limiting frequency.

All mode shapes up to the upper limiting frequency have to be determined. The combination from the three orthogonal directions is effected by the SRSS value. In the cases in which significant frequencies lie in the rigid-body range of the response spectrum, the rigid-body fraction is determined according to the procedure

$$S = \left[\sum_{i=1}^m S_i^2 + \left(\sum_{i=m+1}^n S_i \right)^2 \right]^{1/2}$$
$$S = \left[\left(\sum_{i=1}^m S_i^2 \right) + S_{st}^2 \right]^{1/2}$$

where

S_{st} = rigid-body fraction

n = total number of frequencies

The residual load of each of the three main directions can also be substituted with a static load condition with the acceleration value $b(f_{gr})$. The resulting sectional magnitudes are superimposed for each excitation direction with those resulting from the dynamic responses by the SRSS value.

In the response spectrum method, it is examined if there are present frequencies in close proximity to each other. In case they should have a considerable influence, this influence has to be determined as follows:

(1) Procedure for the group formation

$$S = \left[\sum_{i=1}^n S_i^2 + \sum_{q=\ell}^p \sum_{m=n}^v S_{\ell q} S_{mq} \right]^{1/2}$$

In using the group formation procedure, the inherent shapes in close proximity to each other have to be divided into groups, which combine all inherent shapes whose frequency lies between the lowest frequency in the group and a 10% higher frequency.

(2) Procedure of the 10%

$$S = \left[\sum_{i=\ell}^n S_i^2 + 2 \sum \left| S_{\ell} S_m \right| \right]^{1/2} \quad \ell \neq m$$

In order to determine which mode shapes are in close proximity to each other in the application of this procedure, the following equation was used:

$$\frac{w_m - w_{\ell}}{w_{\ell}} \leq 0.1$$

Seismic Loading and Acceptance Criteria

1. Definition of Load Combinations That Include Seismic and Associated Acceptance Criteria

a. Belgium

The ASME Section III Code behavior limits are used for piping and supports. For guidance on load combinations, Section 3.9.3 of the USNRC standard review plan is used. This criterion is supplemented by a 4g-acceleration design load on active values and a maximum permitted deformation on pipe support of 0.8mm (OBE) and 1.6mm (SSE).

b. Canada

As a function of safety, pipes are classified as ASME Classes 1, 2, 3 or B31.1. General deformation limits are not specified, except under deadweight where up to 0.01" of sag is permitted. The designers do, however, watch for limits due to interferences and proximity to structures or equipments.

Tables G-1 and G-2 provide some of the load group summary and the applicable behavior criteria limits for nuclear piping systems in Canadian-designed nuclear power plants.

Except for different treatment of earthquake loads, i.e., (1) primary stresses including earthquake (either DBE or SDE) limited to ASME Service Level C, (2) seismic fatigue effects added to normal and upset fatigue effects, and (3) seismic event not considered coincident with pipe break in seismically qualified piping, all other load combinations and behavior criteria limits are identical to those used in the United States, i.e., as per ASME Code.

c. France

Load combinations for piping are achieved per the principles given in the RCC-M [Ref. G-4] code, as well as the acceptance criteria.

For supports, each component of the piping load is maximized, and component effects are maximized when combined.

For piping, temperature transients are analyzed for the fatigue evaluation and subcycles taken into account (see RCC-M for the algorithm used).

Pipe rupture and SSE loads on supports and containment penetrations are combined using the SRSS method.

d. Italy

The load combinations and acceptance criteria for ASME equivalent Class 1 are contained in Table G-3.

e. Japan

S_1 and S_2 earthquake loads are evaluated as follows:

- (1) Primary stress limits for S_1 and S_2 are Level C and D limits respectively in ASME Code Section III for Class 1 piping, and S_y (yield stress) and $0.9 S_u$ (S_u : ultimate tensile stress) for Classes 2 and 3 pipings.
- (2) Secondary stress by only earthquake, S_1 and S_2 , shall be evaluated and stress limits are $3S_m$ for Class 1 piping and $2S_y$ for Classes 2 and 3 piping. If the stress is exceeded, elastic-plastic analysis per ASME Section III may be performed.

A current draft of the detailed stress limits permitted in the various safety classes of piping in Japan can be found in Reference G-1.

f. Sweden

For the Class 1 pipe and load combination:

- (1) Dead + Line + Pressure (Primary Stress)

ASME III NB-3652 limits are used.

- (2) Dead + Line + Pressure + SSE (Primary Stress)

ASME III NB-3656 Level D limits are used supplemented in the ASEA-ATOM design by functional capability criteria. It should be noted that OBE seismic loads are so low in Sweden that they do not affect design.

- (3) Dead + Live + Pressure + Thermal + Support Settlement
(Primary + Secondary)

ASME III NB-3653 Level A is used.

- (4) Dead + Live + Pressure + SSE + Thermal + Support Motion
(Primary + Secondary)

This condition is not considered in Swedish applications.

g. Federal Republic of Germany

The limits of the reference stresses and the reference ranges of stress for the components of the primary loop are defined in the safety regulations KTA 3201.2 in Section 7.7.3.

2. Fatigue Analysis Considerations

a. Belgium

ASME III fatigue analysis requirements are followed.

b. Canada

The fatigue analysis required in the ASME Code is performed. In addition, for Service Level C conditions involving design earthquake, fatigue evaluation as per CAN3-N289.3-M81, Section 6.3, is performed.

c. France

The requirements of RCC-M [Ref. G-4] are followed with respect to fatigue analysis.

d. Italy

ASME-III fatigue analysis requirements are followed.

e. Japan

Fatigue usage factor only by earthquake is added to others, and cumulative usage factor shall be less than 1.0.

f. Sweden

ASME-III fatigue analysis requirements are followed. However, the cumulative usage factor is limited to 0.5.

g. Federal Republic of Germany

For the prevention of failures due to fatigue under changing stresses, a fatigue analysis is conducted for the components of the primary loop and for those of the external systems. For piping of the primary loop, a difference is made between

- simplified proof of safety against fatigue,
- elastic-fatigue analysis, and
- simplified elastic-plastic fatigue analysis.

Details of the procedure are specified in the safety regulations KTA 3201.2, Section 7.8.

The criteria for the performing of fatigue tests and the applicable calculation procedures for the external systems are represented in the General Specification "Basic Safety" (Attachment 2 to the RSK directives for pressurized water reactors, Section 4.2). The criteria for the conducting of fatigue tests and the permissible calculation procedures can be gathered from the ASME Code, Section III, Subsections NB and NC.

3. Nozzle Load Limits on Equipment

a. Belgium

The nozzle load limits for all load conditions are defined in standard interface documents plus equipment supplier data. Actual nozzle loads are determined from analytical models that include both piping and equipment.

b. Canada

The nozzle load limits on equipment are primarily set by the requirements of the ASME Code for design and the various service conditions. The pipe supports are modified so that the nozzle loads on equipment are within the requirements of the Code and/or manufacturer. Table G-4 shows the stress levels that are guidelines currently followed at Ontario Hydro in the initial design stage.

c. France

The nozzle load limits for all load conditions are defined in standard interface documents plus equipment supplier data. Actual loads are determined from analytical models that include both piping and equipment.

d. Italy

Nozzle load limits are based on previous experience data, API standards data, and flange allowable limits.

e. Japan

Piping design follows equipment design; therefore, equipment designers evaluate umbrella loads at the nozzle based on the best-estimated values by past experience and considering plant design conditions.

f. Sweden

For pumps--according to suppliers specifications. For pressure vessels and similar nozzle loads--based on pipe dimensions used.

g. Federal Republic of Germany

In general, limiting loads on nozzles are determined by design formulas that are based on previous piping calculations and equipment vendor warranties.

As proof of the permissible loads of connecting pieces, the stresses in the penetration area of the nozzle into the vessel, the piping at the nozzle, and the vessel at the nozzle have to be evaluated. The stresses due to inside pressure are determined with the aid of the design calculation. The resulting stress intensities are deducted from the permissible stresses of the individual degrees of stress so that a "residual stress matrix" results.

If the values of this matrix are not exceeded by the stresses resulting from the loads of the connecting pieces, the admissibility of the loads of the connecting pieces is proven. Container connecting pieces with DN 50 and smaller are tested only then, if this is expressly warranted because of their safety-technical significance.

The stresses caused in the connecting-piece penetration area by external forces and momentums are generally calculated with the Bijlaard method. With this method are determined both the primary local diaphragm stresses (P_L) and the secondary bending stresses.

4. Pipe Support and Anchorage Criteria

a. Belgium

The ASME III-NF Code is applied. No fatigue analysis is performed on supports. Toughness requirements (KCV) are specified in order to avoid brittle fracture of supports.

Anchor bolts are designed in accordance with ACI-349, Appendix B. For the expansion bolts, an anchor depth sufficient to avoid concrete rupture is generally required. An overlength of 20% is specified on top of the length determined by B.4.2 of ACI-349 in order to keep a tolerance margin for erection problems.

Allowable loads are 50% of ACI limits, which are considered too high, especially when slipping of the bolt is considered.

For small loads, standard anchor bolts are allowed with limits equal to the limits of ACI-349 - nonductile option (i.e., allowable loads are $\frac{x - 2\sigma}{\sigma}$ where x is the mean pull-out force in static tests and σ the standard deviation).

b. Canada

The stress limits for supports and anchor bolts are as per ASME Section NF and Appendix XVII. The poured-in-place and expansion-type anchor bolts are load rated in accordance with the Canadian Standard CAN3-N287.3-M82.

The guidelines used for supports are as follows:

- Maximum 4° to the vertical for hangers.
- Up to 2" for variable spring supports. Under seismic loads, these supports are not permitted to bottom out.
- Greater than 2" for constant spring supports.

Vertical rods are used in seismically designed lines. The designers have to ensure from analysis that the vertical acceleration at these locations is less than unity. Thus, liftoff or net compression in these rods is avoided.

Consistent with Canadian seismic design philosophy, under seismic loading conditions, the pipe and the support loads are limited to ASME Service Level C allowables.

c. France

The requirements of RCC-M [Ref. G-4] are followed with respect to support and anchorage criteria.

d. Italy

Allowable stresses and other behavior criteria are defined by ASME III-NF or support manufacturer data. Expansion anchor bolt criteria are defined by experience and results of testing of supports for the CAORSO nuclear power plant [Ref. G-5].

e. Japan

Stress limits of supports are based on the concept considering stress classifications of both ASME Code and AIJ (Architect Institute of Japan) design guideline, "Design Standard for Steel Structures." A draft of detailed design requirements can be found in Reference G-1.

Basic concept of stress limit is specified as follows:

- (1) Stress is evaluated for loads as tensile, shear, compression, bending, bearing, and buckling using specified formula. Stress for bolts, tensile, and shear are specified.

- (2) Primary stress limits for S_1 and S_2 are condition III_{AS} and IV_{AS}, respectively (roughly the same concept as Levels C and D in ASME Code), which are 1.5 times Condition I and II limits. For materials of which allowable stresses are based on yield stress, not ultimate tensile stress, 1.2 to 1.35 times the III_{AS} limit is allowed for IV_{AS}.
- (3) Primary stress plus secondary stress amplitude except bolt under only earthquake loads of S_1 and S_2 shall be evaluated. Stress limit is two times the primary stress limits for III_{AS}, except bearing and buckling of which limits are the same as primary stress limit.
- (4) Verification by test is also allowed instead of stress analysis.

f. Sweden

Support design is in accordance with ASME III Section NF. Special requirements have been developed for dynamically loaded anchor bolts.

g. Federal Republic of Germany

The permissible stresses for component support structures are prescribed in the safety-technical directive KTA 3205.1 in Chapter 8. The permissible stresses for the stress analysis are determined according to design classes (H, HZ, HS) and are given as a multiple of the stress standard value S_m . The classification of the load cases and of the stresses are given in Tables G-5 and G-6.

For the determination of the stress standard value S_m , the following characteristic strength values are used:

R_{eT} = minimum value of the yield point at a temperature T

R_{mT} = minimum value of the tensile strength at ambient temperature

$R_{e0.2T}$ = minimum value of the 0.2% yield strength at temperature T

The S_m values are determined as follows:

- (1) for ferritic steels

$$S_m = \text{Min} \left\{ \frac{R_{eT}}{1.5}, \frac{R_{mT}}{2.4} \right\}$$

- (2) for structural steels St 37 and St 52 according to DIN 17100

$$S_m = \frac{R_{eT}}{1.5}$$

- (3) for austenitic steels

$$S_m = \text{Min} \left\{ \frac{R_{e0.2T}}{1.1}, \frac{R_{mT}}{2.4} \right\}$$

(4) for bolts

$$S_m = \text{Min} \left\{ \frac{R_{eT}}{K_1}, \frac{R_{mT}}{K_2} \right\}$$

Expansion anchor allowables are limited by a safety factor of three against pullout.

5. Application of Snubbers as Pipe Supports

a. Belgium

In recent Belgian nuclear plants, the total number of seismic support snubbers has ranged from 500 to 850 per plant. There are no limitations as to the use of either hydraulic or mechanical snubbers. However, visco-elastic snubbers (Pipework Dampers) with no moving parts, which have been developed in West Germany, are being evaluated for possible use in the future.

b. Canada

Use of snubbers is kept to a minimum in pipe design. However, when it cannot be avoided, designers have a tendency to choose mechanical over hydraulic snubbers. Mechanical snubbers have less inspection requirements. To minimize known problems with snubbers in Ontario Hydro, a program is being considered where all snubbers will be tested on site before and after their installation.

c. France

As a result of standard design, snubber installations in nuclear plants in France have been kept to a minimum. In the 900 MWe standard plant, the total number of snubbers (hydraulic) is approximately 300. In the newest 1400-MWe N-4 plant design, the total number of snubbers has been reduced to less than 100. The French standard plant seismic design is roughly equivalent to a U.S. 0.2g zero period ground acceleration in the amplified response frequency range.

d. Italy

In general, hydraulic snubbers are used for large-bore pipes. Small-bore pipes typically use mechanical snubbers. The total number of seismic snubbers being installed typically exceeds 1,000 per plant.

e. Japan

Plant engineering tries to avoid snubber-type supports if possible because of high cost considerations. Snubber-type supports are used when enough thermal flexibility cannot be provided by piping arrangement, and the piping system is required to be supported as rigid in the seismic design condition.

Recently, the application of mechanical snubbers has increased compared with oil snubbers, at least in the areas of high radiation exposure and maintenance difficulty.

f. Sweden

Snubbers have seen limited use in Sweden since only two plants have been designed for earthquakes. At this time there are no preferences or limitations applicable to snubber use. ASEA-ATOM avoids hydraulic snubbers because of maintenance problems.

g. Federal Republic of Germany

Snubbers are used for the protection of piping and components. Both hydraulically and mechanically operated snubbers are permitted. They are to be of the double-action type. They have to be of equal loading capacity for the cases of stress and pressure. The piping movements due to thermal expansion may not be hindered by the snubbers and their attachments.

Special requirements as to which types of snubbers to use for piping systems are contained neither in the control procedures nor in guidelines nor in specifications. Generally, mechanically operated snubbers are used for low-rated loads (up to about 10 kN) and hydraulically operated snubbers for higher loads.

Snubbers are generally subjected to structural or type tests in accordance with special specifications. If such structural or type test does not exist, for each snubber size an endurance test, including an operational test, has to be conducted. The operational test of the snubbers includes a stroke measurement, the repeated measurement of the idling speed and of the frictional resistance, and loads of 10 seconds each for oscillations at various frequencies (1 to 20 Hz).

The number of snubbers used in nuclear power plants in the Federal Republic of Germany has experienced the same escalation as in other countries. Current stations typically have more than 1,000 snubbers. However, the new Konvoy plant's design goal is to eliminate all snubbers on piping.

While this goal may not be completely realized, it is assumed that fewer than 100 seismic snubbers will be required per plant on the Konvoy series. Consideration is also being given to the use of "pipework dampers" being manufactured in the Federal Republic of Germany, which are considerably less complex and less expensive than the other snubber designs used to date.

Modeling and Layout Assumptions Used in Design of Piping

1. Assumptions Used in Modeling Piping and Supports for Deadweight and Thermal Loads

a. Belgium

Computer analyses for thermal loads of all ASME Classes 1, 2, and 3 piping larger than 1-1/2 inches, including supports, are required. ASME Classes 1, 2, and 3 piping systems between 1-1/2 and 3/4-inch-diameter for temperature greater than or equal to 50°C are also computer analyzed.

In thermal analysis, all supports other than variable and constant spring supports are usually considered rigid. Variable spring support constants are defined by the manufacturer or as a result of tests performed on the spring or

snubber support. Constant spring supports are considered as an external load in deadweight analysis and are not considered as acting in the thermal analysis.

b. Canada

The application of simplified or noncomputer analysis procedures to piping is not addressed.

In thermal analysis, all pipe supports except snubbers are considered in the computer model. Supports are modeled considering their relative support stiffness based on manufacturer or supplier recommendations or are computed on the basis of simple beam-bending calculations. Table G-7 shows the relationships assumed for various types of supports as a function of the type of loadings--gravity, thermal, and dynamic.

c. France

All elevated-temperature piping 1" and larger is thermally evaluated. In deadweight and thermal analysis, all pipe supports are considered rigid except for constant and variable spring hangers and snubbers. For thermal analysis, anchor points, guides, and sway struts are considered in the model. Differential support displacements are considered explicitly in the design. These displacements include concrete shrinkage, creep and thermal expansion, building differential settlements, building seismic differential displacements, relative displacements of double wall containment under aircraft crash, containment pressure test, and LOCA pressurization.

d. Italy

Computerized thermal analysis in general is required. Spring constants for variable spring hangers are considered in the deadweight analysis but are ignored in the thermal analysis. Constant spring hangers are considered as external forces in deadweight analysis but are ignored in the thermal analysis. Fixed supports (hangers, U bolts, etc.) are generally considered rigid in deadweight and thermal analyses.

e. Japan

Spring hangers and snubbers are not considered in thermal flexibility analyses. Supports, except spring hangers and snubbers, are conservatively assumed to be rigid for thermal analysis. Generally, spring constants for spring hangers are not considered in the deadweight and thermal analyses, and spring constants for snubbers are not considered in thermal analysis. Generally, constant spring hangers are not used for nuclear safety-related piping in PWRs. In BWRs, constant spring hangers are considered the same as spring hangers in the analysis.

f. Sweden

Computer analysis is generally required for thermal loads on piping. Finite stiffnesses are considered for supports in deadweight and thermal analyses. For spring hanger stiffness, supplier information is used. Constant spring hangers are modeled as constant force elements in deadweight and thermal analyses.

g. Federal Republic of Germany

For the analysis of a piping system against thermal loading cases, all supports except snubbers and fixed suspension mountings (constant spring hangers) are considered in the calculation. It is generally assumed that the fixed supports are rigid. However, the flexibility can be allowed for a support rigidity matrix, e.g., a support in the model.

Spring hangers are considered as restraining thermal movement and are modeled as linear springs. In the deadweight loading case, a stop is assumed in a vertical direction, or the vertical forces to be absorbed by the hangers are inserted in the calculations.

Fixed suspension mountings (constant spring hangers) exert an almost constant bearing pressure (supporting force) on the piping over the entire travel range. They are used at the support points at which are expected greater vertical movements. In the deadweight analysis, a stop is assumed in vertical direction for the fixed suspension mountings, or the vertical forces to be absorbed by the fixed suspension mountings are inserted in the calculation.

2. Assumptions Used in Modeling Piping and Supports for Seismic Loads

a. Belgium

In seismic analyses, all support stiffnesses are considered explicitly. Stiffness data on all supports are determined from manufacturers' catalogs and test results. Variable spring hangers are included in seismic modeling. Constant spring hangers are not considered in seismic analysis models.

b. Canada

Modeling assumptions applicable to seismic analysis of piping are shown in Table G-7. All supports are modeled with their respective stiffness values unless the support meets the following stiffness or frequency requirements.

Most seismic supports are required to have their fundamental frequency greater than 33 Hz. The following stiffness criteria are also used as guidelines:

$$\text{Rotational stiffness} \geq \frac{35 EI}{L}$$

$$\text{Direct stiffness} \geq 10 \text{ times the stiffness of the pipe}$$

where

E = Young's Modulus

I = Movement of inertia

L = Deadweight hanger spacing of the pipe

For stiffnesses greater than those indicated, the supports are considered rigid.

c. France

In seismic modeling of piping systems, fixed supports are considered rigid. Variable spring and constant spring hangers are not considered in seismic piping models. Snubbers are assumed to have a displacement of $\pm 2\text{mm}$ under normal load (4mm peak to peak). The use of snubber-type support is not encouraged. "Put as much as necessary and as few as possible" is the rule. In order to meet this objective, guides and sway struts are put in locations where thermal piping displacements are small and up to the point where thermal expansion stresses are close to the allowable. Checks for piping sliding in the guides are made by comparing reactions on guide to standard predetermined values. If further restraint is needed, snubbers are used.

d. Italy

In seismic modeling of piping systems, supports are considered generally rigid. Variable and constant spring hangers are not included in the seismic piping models.

e. Japan

In seismic modeling of piping systems, supports are generally not considered rigid. Constant and variable spring hangers are not considered in the seismic piping system models.

f. Sweden

In seismic piping system models, the spring constants for all supports are determined on a case-by-case basis. In complicated cases, this may require special analysis or testing. For spring hanger characteristics, supplier's information is used. Variable springs are included in the seismic model. Constant spring hangers are included in the seismic model as constant force elements.

g. Federal Republic of Germany

In the earthquake analyses of piping, it was assumed that all fixed supports are rigid. Based on present experiences, nowadays the flexibility of support structures is taken into account in the design of piping systems. Especially for the loading case of "aircraft impact," the deformation properties of a support are considered in the model when using the static substitute load method.

3. Application of Nonlinear Piping Analysis

a. Belgium

Nonlinear analyses of piping systems are limited to LOCA loading conditions.

b. Canada

Nonlinear analyses are limited to pipe-break conditions.

c. France

Nonlinear analyses are authorized, not recommended. They may be necessary to evaluate special effects such as the effect of piping shakedown on loads applied to equipment nozzles or the stresses generated in an unbroken pipe by a broken pipe.

d. Italy

Nonlinear piping analyses are generally limited to Faulted (ASME-III Service Level D) loading analyses.

e. Japan

Piping systems are usually modeled and analyzed linearly, although nonlinear structural analysis is not prohibited. System analysis of the reactor coolant system piping has considered nonlinear analysis for pipe break.

f. Sweden

Nonlinear analyses are permitted in connection with the evaluation of postulated pipe failures. In actual cases of degraded pipes, nonlinear analysis may be permitted on a case-by-case basis.

g. Federal Republic of Germany

No nonlinear analyses are conducted for piping systems. In cases where a support has a nonlinear characteristic curve, this approximation method can be taken into consideration through an adequate linearizing action, i.e., through a linear substitute spring.

No special indications are contained in the control procedures in this respect.

4. Gap Consideration in Piping Supports

a. Belgium

Support gaps in piping systems are limited to $2\text{mm} \pm 1\text{mm}$ in the hot condition. Gaps are not explicitly considered in the analysis.

b. Canada

Maximum gap specified on the supports designed so far is limited to $\pm 0.125"$. Modeling of large gaps in computer models is not well understood when only linear methods are being used. Gaps are always kept to the minimum possible and are not substituted for snubbers. In fact, for this reason, thermal stops are not considered as pipe supports.

c. France

Gaps specified are 2 to 3mm in hot condition. However, field erection tolerances permit larger gaps in the field. It is recognized that larger gaps would be beneficial to the piping but larger-impact loads would have to be considered and very likely the support design modified.

d. Italy

Support gaps in piping systems are limited to $\pm 0.75\text{mm}$. Gaps are not explicitly considered in analysis.

e. Japan

No support gap limit is specified, but a value of $\pm 2\text{mm}$ is typical. Gaps are not explicitly considered in analysis.

f. Sweden

Support gaps are typically $\pm 1\text{-}2\text{mm}$. No limit has been specified. Gaps are not explicitly considered in analysis.

g. Federal Republic of Germany

Gaps for supports are not specified in the German control procedures. Such gaps are determined, e.g., for friction bearings, in the design documents. This can amount up to 3mm , taking into consideration the actual thermal elongation of the piping. Reference is made to the results of the HDR studies.

The thermal loads are reduced because of the gaps at the supports. The installation of snubbers is optimized, taking into consideration the supports and their gaps, by means of design calculations.

Piping System Design Responsibilities and Organization

1. Belgium

For the four nuclear plants recently commissioned (1983) or being erected (planned to be commissioned in 1985), the following organization has been used for piping design:

- a. The piping layout is performed by the plant layout group of the architect-engineer (AE) using the plastic model as a working tool;
- b. Piping isometrics are drawn by the piping contractor using piping composite drawings (orthographics) from the AE layout group;
- c. Layout validation and support specification are performed by the piping stress analysis group;
- d. Support design, fabrication and erection, and piping fabrication and erection are subcontracted to the piping contractor;
- e. Final piping analyses are performed using data (stiffnesses, local stresses at integral attachments) from the stress reports of the supports;
- f. As-built verification and piping stress report reconciliation are performed using as-built drawing (support drawings and isometrics) drawn by the piping contractor.

2. Canada

The Ontario Hydro piping organization and design process is summarized in Figures G-1, G-2, and G-3.

3. France

General layout drawings are prepared by FRAMATOME, taking into account the general building drawings prepared by its client or associate. Main equipment, primary loop, and main steam lines inside containment and outside containment down to the main steam isolation valve have an impact on the reactor containment building architecture and are thus studied together with the building in an early phase. A few other lines are studied in the preliminary phase (e.g., RHR).

In the design phase, FRAMATOME prepares detailed piping layout drawings, isometric drawings, and analysis for piping inside containment. Piping for the main steamline and feedwater line penetrations and outside containment to the containment isolation valves is included.

FRAMATOME determines the location and function of each support and then transfers the detailed design of the supports and the fabrication drawings for piping and support to a subcontractor, which installs them under FRAMATOME supervision.

For other piping outside containment but still in the NSSS, FRAMATOME subcontracts it with design specifications. Supports are treated as previously.

Balance of nuclear island piping is in EDF's scope or other companies (export projects).

In the NSSS organization, FRAMATOME provides a significant part of the design effort and design methods. Research and development is performed in accordance with agreements with EDF and CEA.

The RCC-M [Ref. G-4] design and construction code reflects largely the practice of FRAMATOME and EDF on the subject.

4. Italy

Piping system design responsibilities used by Ansaldo Impianti are summarized in Figure G-4.

5. Japan

Piping system design responsibilities and organization are developed by individual plant designers and utilities. The information is provided to MITI as part of the construction permit request information.

6. Sweden

Piping design organization and responsibilities are developed by the plant designer on a case-by-case basis.

7. Federal Republic of Germany

The design of the piping systems for the turnkey nuclear power plants customarily built in the Federal Republic of Germany is carried out by the general contractor together with piping manufacturers. The design process is schematically represented in Figure G-5.

After (1) the determination of the design, based on consideration of the pressure, temperature, other loads, material, etc., and (2) the performing of a static structural analysis wherein the sufficient stability is ascertained under consideration of the static loads, e.g., through thermal expansion or deadweight of the system, (3) the dynamic behavior of the system is studied. The dynamic stress of the components can be determined, e.g., with the aid of floor response spectra.

After (4) the superpositioning of the loads resulting from the static and the dynamic analyses, there is performed the final analysis of the components that leads to (5) the confirmation of the design requirements. The design is fully examined by an independent supervisory organization (Technischer Ueberwachungs-Verein, TUV (Technical Supervisory Association, TUV)). It is examined, to determine if the piping system in question meets the requirements established in the licensing decision. This means that the design is subjected to a design review. The design review comprises the evaluation of:

- The structural design
- The dimensioning and the materials used
- The manufacturing and production processes
- The capability of being tested and the accessibility for maintenance and repairs, based on calculations and specifications.

Static and dynamic structural analyses are verified by the Technical Supervisory Association with its own computer programs.

TABLES AND FIGURES FOR APPENDIX G

Tables

G-1	Canadian Load Group Formation Summary
G-2	Canadian Class 2 Stress Equations
G-3	Italian Class 1 Piping Other Than Main Steam and Connected Piping: Load Combinations and Acceptance Criteria
G-4	Canadian Nozzle Load Structure Level Used by Container Criteria
G-5	German Classification of Loading Cases
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G-1	Nuclear Piping Design Process, Ontario Hydro Determination of Static Loads
G-2	Nuclear Piping Design Process, Ontario Hydro Determination of Dynamic Loads
G-3	Nuclear Piping Design Process, Ontario Hydro Final Stress Analysis and Reports
G-4	Schematic Representation of Ansaldo Impianti Design Process for Reports
G-5	Typical German Schematic Representation of Design Process for Components

Table G-1

CANADIAN LOAD GROUP FORMATION SUMMARY

Load Group ¹ Number	Applicable ² Operating Conditions	ASME Load Classification	Stress Produced P - Primary S - Secondary	Load Source
LG1	N, U, E, F	Sustained	P	Pressure Deadweight Preload forces Cold springing ³
LG2 _±	U, E, F	Expansion	S	Thermal expansion Pressure expansion Thermal anchor point movements
LG3	U, E, F	Occasional	P or S	Dynamic anchor point movements
LG4 _±	U	Occasional	P	Water hammer Valve thrust
LG5 _±	E	Occasional	P	BDE inertial loads DBE rigid response inertial loads Water hammer Valve thrust
LG6 _±	F	Occasional	P	DBE inertial loads DBE rigid response inertial loads Water hammer Valve thrust Jet impingement

¹Load group files contain moment, reaction, and deflection data with proper sign or maximum and minimum values as required to satisfy code evaluation relationships.

²N - Normal Operation Conditions (Level A) U - Upset Operating Conditions (Level B)
E - Emergency Operating Conditions (Level C) F - Faulted Operating Conditions (Level D)

³Only the reactions on equipment and anchors are retained from a cold spring analysis. Therefore, the load case does not affect stress in the pipe. It is included in load group LG1 for support-load evaluation only.

Table G-2

CANADIAN CLASS 2 STRESS EQUATIONS

Equation Symbol	Operating Condition	Equation ¹	Associated Load Groups	Stress Limit
8	Normal (Level A)	$\frac{P_r d^2}{D_o^2 - d^2} + \frac{0.75i}{Z} MA$	MA = LG1	SH
10	Upset (Level B)	$\frac{i}{Z} MC$	MC = LG2 + LG3	SA
11	Upset	$\frac{P_r d^2}{D_o^2 - d^2} + \frac{0.75i}{Z} MA + \frac{i}{Z} MC$	MA = LG1 MC = LG2 + LG3	SH + SA
9U	Upset	$\frac{Pd^2}{D_o^2 - d^2} + \frac{0.75i}{Z} (MA + MBU)$	MA = LG1 MBU = LG4 + (LG3) (SC4)	2 SH
9E	Emergency (Level C)	$\frac{Pd^2}{D_o^2 - d^2} + \frac{0.75i}{Z} (MA + MBE)$	MA = LG1 MBE = LG5 + (LG3)(SC5)	1.8 SH
9F	Faulted (Level D)	$\frac{Pd^2}{D_o^2 - d^2} + \frac{0.75i}{Z} (MA + MBF)$	MA = LG1 MBF = LG6 + (LG3)(SCG)	2.4 SH
PR	Pipe Rupture	$\frac{Pd^2}{D_o^2 - d^2} + \frac{0.75i}{Z} (MA + MBU) + \frac{i}{Z} MC$	EQ. 9U + EQ. 10	.8 (1.2 SH + SA)
AV	Active Valve	$\frac{Pd^2}{D_o^2 - d^2} + \frac{1}{Z} (MA + MB) + \frac{i}{Z} MC$	EQ. 9 + EQ. 10 MB MAX (MBU, MBE, MBF)	(AVC)(SY)

¹a. The constant 0.75i is never less than 1.0. The stress intensification factor is never less than 1.0. P_r is the design pressure and P is the peak pressure.

b. All moment terms are evaluated as three components M_x , M_y , M_z . The terms MA, MD, MC actually represent the square root of the sum of the squares.

$$MA, MD, MC = \sqrt{M_x^2 + M_y^2 + M_z^2}$$

c. For the normal and upset conditions, Equations 8 and 9U plus 10 or 11 must be satisfied.

d. Dynamic anchor movements (LG3) may be included in Equation 9 or 10 but not in both.

e. S_y is the yield stress of pipe at design temperature.

Table G-3

ITALIAN CLASS 1 PIPING OTHER THAN MAIN STEAM AND CONNECTED PIPING:
LOAD COMBINATIONS AND ACCEPTANCE CRITERIA

Condition	Load Combination	Acceptance Criteria
Design	$P_D + W + OBE_1$	Eq. 9 $\leq 1.5 S_s$
Service Level A	$P_0 + T_1$	Eq. 10 $\leq 3.0 S_s$ or Eq. 12 $\leq 3.0 S_s$ and Eq. 13 $\leq 3.0 S_s$. $U \leq 1.0$
Service Level B	$P_0, T_1, OBE_1, OBE_D, RV_{2AI}$ and RV_{2BI} Dynamic loading combinations consist of the following: $(OBE_1^2 + OBE_D^2 + RV_{2AI}^2)^{1/2}$.(1) (2)	To be analyzed in conjunction with Normal Conditions.
Service Level C	$P_D + W + (OBE_1^2 + RV_{2AI}^2)^{1/2}$ (3) $P_0 + W + (OBE_1^2 + PS^2)^{1/2}$ $P_{PATNS} + W + RV_{2AI}$	Eq. 9 $\leq 2.25 S_s$
Service Level D	$P_0 + W + AI$ $P_0 + W + (SSE_1^2 + PS^2)^{1/2}$ $P_0 + W + (SSE_1^2 + AP_1^2 + J^2)^{1/2}$ $P_0 + W + (SSE_1^2 + VCL_1^2 + J^2 + RV_{2AI}^2)^{1/2}$ $P_0 + W + (SSE_1^2 + WP_1^2 + CO_1^2 + J^2 + RV_{2AI}^2)^{1/2}$ $P_0 + W + (SSE_1^2 + CHUG_1^2 + RV_{2AI}^2 + J^2)^{1/2}$	Eq. 9 $\leq 3.0 S_s$
Test	$P_1 + W$	NB - 3226

Table G-3 (Continued)

Notation for Class I piping other than main steam and connected piping: Load combinations and acceptance criteria.

Subscript I:	Inertial forces effects
Subscript D:	relative anchor movements effects
P _D :	design pressure effects
W:	weight and sustained loads effects
OBE:	operating basis earthquake
RV _{2A} :	structural induced vibrations by S/R Valves operation (first actuation, see note 4)
RV _{2B} :	structural induced vibrations by S/R Valves operation (subsequent actuation, see note 4)
PS:	recirculation pump seizure effects
AI:	structural induced vibrations by Aircraft Impact
SSE:	safe shutdown earthquake
AP:	structural induced vibrations by Annulus Pressurization loads
VCL:	structural induced vibrations by Vents Clearing loads
WP:	structural induced vibrations by Wetwell Pressurization
CO:	structural induced vibrations by Vents Condensation Oscillations
CHUG:	structural induced vibrations by Chugging loads
P ₀ :	operating pressure effects. TO be selected according to system condition associated to specific loading combination
PPATWS:	peak pressure associated to ATWS event effects
P _T :	test pressure effects
T _E :	temperature distribution and thermal anchor movements effect jet impingement load

-
- Notes: (1) This loading combination is in the probability range classified as Emergency. For design however it is considered an Upset Condition. No fatigue analysis is required.
- (2) Single Safety or Relief Valve Blowdown
- (3) Multiple S/R Valves Blowdown
- (4) - 1 to 16 S/R Valves will lift in first actuation condition. It will be assumed simultaneous discharge of 16 Valves: the effect of S/R Valves discharging from the same M.S. header will be combined by SRSS method
 - low-low set Valve will cycle during subsequent actuation

Table G-4

CANADIAN NOZZLE LOAD STRUCTURE LEVEL USED BY CONTAINER CRITERIA

Level of Stress at nozzle-pipe suction	Magnitude of stress, psi, for calculation of					
	Deadweight Loads		Thermal Loads		Seismic Loads	
	Moment	Force	Moment	Force	Moment	Force
High	1500	Based on Deadweight-	10153	3000	15230	870
Medium	1500	Hanger- Spacing.	7615	2000	10153	580
Average	1500		5076	1500	5076	290
Low	1500		2538	1000	-	145

Note: Pipe material is SA106 Gr. B

Table G-5
GERMAN CLASSIFICATION OF LOADING CASES

Line		
1	Authorized operation	Normal operating cases (NB)
2		Abnormal operating cases (AB)
3		Test cases (PF)
4	Accidents	Emergency cases (NF)
5		Accidents (SF)

Table G-6
GERMAN CLASSIFICATION OF STRESSES

Line	Stresses from	Stress Class.
1	Authorized operation: Normal operating cases	H
2		Z
3		Z
4	Pipe break	S
5	Other internal accidents of the plant	Z, S
6	Design [basic] earthquake	Z
7	Safe shutdown [maximum potential] earthquake	S
8	Aircraft impact	S
9	Pressure wave, caused by external explosion	S

Table G-7

CANADIAN RELATIONSHIP BETWEEN SUPPORT-TYPE AND RESTRAINT ASSUMPTIONS

Support Type	Support Description	Support Configuration Requirements					
		Gravity		Thermal		Dynamic	
		Deflect	Rotate	Deflect	Rotate	Deflect	Rotate
AN	Anchor - No free rotation or deflection in any direction.	Yes	Yes	Yes	Yes	Yes	Yes
RR (X,Y,Z)	Rigid Restraint - No movement in the restrained direction.	Yes		Yes		Yes	
US (Y)	Unidirectional Restraint - A vertical (y) support. An RR which supports a negative design load reverts to a US.	Yes		Yes		Yes	
VS (X,Y,Z)	Variable Spring - Supports deadweight and may be used to provide a preload.	Yes		Yes			
CS (Y)	Constant Force Support - If the design travel exceeds a specified value, a VS converts to a CS.	Yes		Yes			
DS (X,Y,Z)	Dynamic Snubber - Resists a suddenly applied load in the positive or negative direction.					Yes	
VS or CS & DS		Yes				Yes	
TS and DS				Yes		Yes

NUCLEAR PIPING DESIGN PROCESS
Figure G-1. Ontario Hydro Determination of Static Loads

NUCLEAR PIPING DESIGN PROCESS
Figure G-2. Ontario Hydro Determination of Dynamic Loads

NUCLEAR PIPING DESIGN PROCESS
Figure G-3. Ontario Hydro Final Stress Analysis and Reports

Figure G-4.

Schematic Representation of
Ansaldo Impianti Design
Process for Reports

Figure G-5. Typical German Schematic Representation of Design Process for Components

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NRC FORM 335 16 E31 2 BIBLIOGRAPHIC DATA SHEET		U.S. NUCLEAR REGULATORY COMMISSION		1 REPORT NUMBER (Assigned by TIDC, add Vol. No., if any) NUREG-1061 Volume 2	
3 TITLE AND SUBTITLE Report of the U.S. Nuclear Regulatory Commission Piping Review Committee Volume 2: Evaluation of Seismic Designs - A Review of Seismic Design Requirements for Nuclear Power Plant Piping				2 Leave blank	
6 AUTHOR(S) The Seismic Design Task Group of the NRC Piping Review Committee (S. Hou, Chairman)				4 RECIPIENT'S ACCESSION NUMBER 5 DATE REPORT COMPLETED MONTH YEAR February 1985	
8 PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) U.S. Nuclear Regulatory Commission Washington, DC 20555				7 DATE REPORT ISSUED MONTH YEAR April 1985	
11 SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) U.S. Nuclear Regulatory Commission Washington, DC 20555				9 PROJECT/TASK/WORK UNIT NUMBER 10 FIN NUMBER	
13 SUPPLEMENTARY NOTES				12a TYPE OF REPORT Regulatory Report	
14 ABSTRACT (200 words or less) This document reports the position and recommendations of the NRC Piping Review Committee, Task Group on Seismic Design. The Task Group considered overlapping conservatism in the various steps of seismic design, the effects of using two levels of earthquake as a design criterion, and current industry practices. Issues such as damping values, spectra modification, multiple response spectra methods, nozzle and support design, design margins, inelastic piping response, and the use of snubbers are addressed. Effects of current regulatory requirements for piping design are evaluated, and recommendations for immediate licensing action, changes in existing requirements, and research programs are presented. Additional background information and suggestions given by consultants are also presented.				12b PERIOD COVERED (Inclusive dates)	
15a KEY WORDS AND DOCUMENT ANALYSIS Piping, seismic design criteria, snubbers					
15b DESCRIPTORS					
16 AVAILABILITY STATEMENT Unlimited			17 SECURITY CLASSIFICATION (This report) Unclassified		18 NUMBER OF PAGES
19 SECURITY CLASSIFICATION (This page) Unclassified			20 PRICE \$		